

Shale Volume Effect on Hydrocarbon Prospectivity of Green Field, Niger Delta, Nigeria

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Abstract

This research presents an investigation on the shale volume effect on hydrocarbon prospectivity of Green Field within Niger Delta, Nigeria. Delineation of potential reservoirs was done with Petrel Version 2010® and OpendTect 4. 6.0® exploration and production softwares, and data obtained were quality checked to eliminate null values. Three different empirical models were used to estimate the shale volume for fifteen delineated reservoirs from the three identified “Green” wells. The shale volume ranges from 0.111 to 0.162 for Green 1, 0.056 to 0.092 for Green 2 and 0.007 to 0.140 for Green 3 reservoirs. An average shale volume obtained from a merger of the three models was compared to the permeability in each of the fifteen reservoirs to determine the hydrocarbon prospectivity of the wells. It was noticed that shale volume increases with a decrease in the permeability. The ratio of shale to sand ranges from 0.125 to 0.192 for Green 1, 0.059 to 0.101 for Green 2 and 0.007 to 0.111 for Green 3 reservoirs. The presence of sand in higher volume which ranges from 0.838 to 0.889 for Green 1, 0.908 to 0.944 for Green 2 and 0.900 to 0.993 for Green 3 reservoirs than shale which ranges from 0.111 to 0.162 for Green 1, 0.056 to 0.092 for Green 2 and 0.007 to 0.140 for Green 3 reservoirs and higher resistivity which ranges from 5.61 to 96.93 for Green 1, 16.01 to 103.42 for Green 2 and 14.75 to 22.17 for Green 3 reservoirs than the conductivity which ranges from 0.0100 to 0.1800 for Green 1, 0.0096 to 0.0625 for Green 2 and 0.0450 to 0.0680 for Green 3 reservoirs are some major signals confirming a substantial hydrocarbon in the reservoirs. Results from this study indicates prospective presence of fractured shale deposits in the study area. Petrophysically, subsurface reservoirs in the “Green” field have reasonable hydrocarbons in their pore-spaces and estimated producibility indicators are good enough to support secondary migration of the oil into the borehole, if developed.

Keywords: Prospectivity; Delineation; Shale volume; Permeability; Hydrocarbon; Quality Checked.

I. INTRODUCTION

The sale of crude oil is known to have driven the economy of a number of crude producers [1]. The Nigeria economy

has been dependent on proceeds from hydrocarbon since 1959, when the first oil well was struck in Oloibiri, in the present day Bayelsa state [1]. Production of petroleum from subsurface strata is based on the understanding of subsurface

geologic and geophysical models; which are built from realistic petrophysical parameters. Petrophysics as derived from two Greek words(*petra* which means “rock” and *physis*, which means “nature”) is centered on the study of rocks properties (both physical and chemical) and their interaction with fluids using parameters such as lithology, porosity (ϕ), permeability (K), water saturation (S_w), hydrocarbon saturation (h_s) and true resistivity (R_t) among others [2]. Through Petrophysics, reservoir engineers and geoscientists get better understanding of reservoir rock properties in the subsurface, particularly the interconnectivities of pores giving rise to the collection and movement of hydrocarbons in the reservoirs [2]. Reservoirs are unit of rocks that are capable of housing hydrocarbon generated by mature source rocks. They are usually characterized by large area extent and good fluid holding/storage capacity. Reservoir rocks are the porous and permeable subsurface rocks that contain commercial deposits of hydrocarbons. Common examples of reservoir rocks are Sandstones, Chalk, Limestone, and Dolomites among others. Measurement and evaluation of these rock properties is done using well logs assessment. A string type of measurement materials also referred to as *Sonde* are dipped into the borehole after which core measurements can be carried out. This will assist the reservoir engineers to detect the rock samples in the bore holes and also make seismic analysis of reservoirs easier. These pieces of information from geological and geophysical investigations are now combined with reservoir engineering to come up with a complete evaluation of the reservoir [3]. The reliability of subsurface reservoir models is dependent on the genuineness of the inputted petrophysical data. It is thus very imperative to ensure valid petrophysical parameters are computed for drilled wells to avoid erroneous executive decisions on wells development and production [4]. Parameters such as porosity (ϕ), permeability (K), water saturation (S_w), shale volume (V_{sh}), HC saturation (h_s), formation resistivity (R_f) and bulk volume water (BVW) are important in assessing an exploration well petrophysically [5]. Among these parameters, the shale volume, porosity and permeability of a reservoir are some of the most important factors to be taken into consideration for effective reservoir characterization and management. This is because other parameters are either dependent directly on them or at least one. Therefore, accurate estimation of these parameters in an identified reservoir is undoubtedly important to enhance validity of other dependent variables. Shale is a grainy, fine, broken pieces of sediment showing high tendency of fissility and made up of very soft, sticky, flat, thin pieces of matters characterized by the presence of hydrous aluminum phyllosilicates and tiny fragmented silt-sized particles of other inherent minerals; majorly calcite and quartz which are formed in the presence of liquids, especially water [6]. Records from geology described shale as a finely stratified and clastic structure formed as a result of overburden and unchanged mineral constituents which were in existence since deposition [6]. Shale is made up of about 2% iron oxides, 6%

feldspar, 58% clay minerals, 5% carbonate minerals and 28% quartz. The highest percentage of the quartz is inherent in the initial sediments from which the shale was formed and not post depositional shale crystals [7]. Sand on the other hand is composed of unconsolidated, fine and coarse material majorly rich in silicate, micas and amphiboles. While shale is sticky when wet and has a high fluids holding capacity, the sand is gritty and sharp but and not sticky when wet [7]. Sand particles have diameters which range from 0.0625mm to 2 mm while that of shale particles range from 0.00391mm to 0,0625mm. It is crystal clear that, the space within a sand particle is larger than that of shale. This is why sand particles have the ability to house hydrocarbon better than shale [8]. Reservoirs sand that contained water has high conductivity and low resistivity but when it houses hydrocarbon, the resistivity increases while conductivity decreases [9]. Determining the presence of shale within the sand body is very essential in evaluating the hydrocarbon prospectivity in any clastic reservoir as a wrongly estimated shale volume will eventually affect the estimation of the water saturation [10]. Shale depositional form and volume determine the porosity and the permeability of reservoirs [10]. Most often than not, attentions have only been on the volume but not on the depositional forms. This has misled reservoir Engineers in taking decisions about the expected volume of hydrocarbon from the reservoir. As it is an established fact that a high shale volume is an indication of low porosity and permeability, depositional forms (such as fractured, dispersed, structural and laminated nature) give a clearer picture of the reservoirs shale as to why the same volume of shale from two different reservoirs gives different porosity and permeability. Based on the aforementioned, this research work is focused on ascertaining the percentage of sand to shale content, comparing the conductivity and resistivity of fluids from the reservoirs in each of the wells, determining the shale volume from a merger of three empirical models established from literatures and comparing the results in all the reservoirs. This will further compare the shale volume with the permeability and predict the predominant shale deposits in the study area so as to determine the hydrocarbon prospectivity of the field. The outcome of the research is expected to help in evaluating correctly the quality of reservoirs by determining accurately, the hydrocarbons potential. This will reduce economic risks associated with hydrocarbon exploration.

II. STUDY AREA

A. *Geology of the study area*

The study area is located in the Niger Delta in the South-eastern region of the country. It is situated between Longitudes 30 – 90° E, and latitudes 40 – 60° N and bounded in the east and west by the Calabar flank and the Benin flank respectively. The Gulf of Guinea formed the southern boundary and the northern boundary is extended to the Anambra Basin, Abakaliki uplift and Afikpo syncline [12]. According to [13], the Niger Delta spreads over an area in

excess of $105,000 \text{ km}^2$. The extension of the study area in the Niger Delta originated from the southwest Cameroon in the east-western direction and terminated at the Okitipupa ridge. The study area is a highly economical basin rich in only one ascertained petroleum system [14]. It is a very prolific hydrocarbon (HC) basin and is no doubt, one of the world largest Tertiary Delta systems. This identified petroleum system is known as the Tertiary Niger Delta and this starts from the Akata to the Agbada Petroleum System and it has shown undoubted reformable reserves of 35 billion bbl of oil and a mixture of light liquid HC and 184 Trillion Cubic Feet (Tcf) of gas [15]. Fig. 1 below is a map showing the geology of the study area.

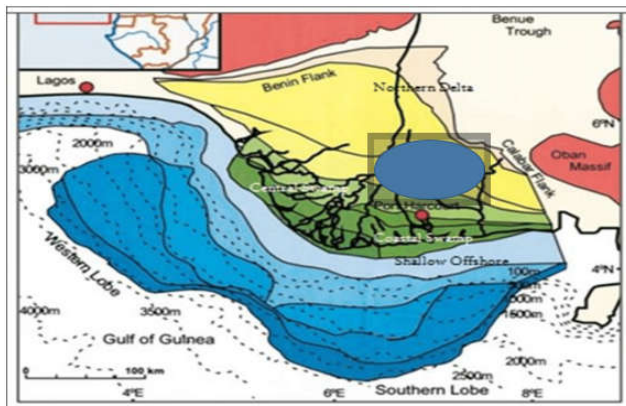


Fig. 1 Map showing the geology of the study area [11].

B. Location of the study area

The study location is situated at the Green field, onshore Niger Delta. It is located within the Shell Petroleum Development acreage. The field is bounded by latitudes 4°N and 6°N and longitudes 6°E and 8°E . Figure 2 below is a map showing the well location points of the study area. Wireline logs utilized for this research were obtained from the well drilled in the area studied.

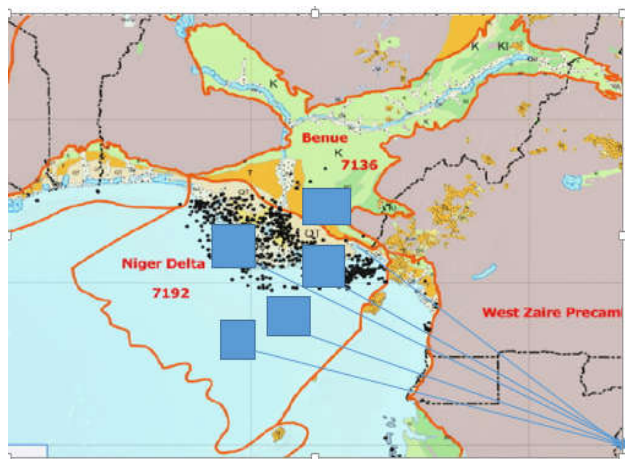


Fig. 2 Map showing the well location points of the study area [11].

III. MATERIALS AND METHODS

Geophysical well log data were obtained from the data bank of the Department of Geology of the Obafemi Awolowo University, Ile-Ife. Due to proprietary reason, the field from which the research is being carried out is hypothetically referred to as “Green” as the real name of the field was not disclosed. The composite well log data used for this research comprised of gamma ray, deep induction, spontaneous potential, resistivity and porosity logs. Qualitative interpretation of data such as identification of lithology, delineation of potential reservoirs and fluids’ contacts determination were done with PETREL version 2010® and OpendTect 4.6.0®. Quantitative estimation of petrophysical parameters such as the shale volume, permeability, porosity, water resistivity, water saturation and irreducible water saturation was also determined by loading the data into Microsoft excel, 2015. Three empirical models demonstrated by [16], [17] and [18] were employed to determine the shale volume. The value of the shale volume used for this research was obtained from a merger of the three aforementioned models. The porosity and the irreducible water saturation were estimated as their values will be needed to determine the permeability of the reservoirs. The sand to shale ratio, resistivity and conductivity of fluids for each of the fifteen delineated reservoirs were also determined in order to arrive at a reasonable conclusion. The shale volume was compared with the permeability in order to have an idea of the hydrocarbon prospectivity of the reservoirs.

IV. ESTIMATION OF SHALE VOLUME

Although hydrocarbon reservoirs in the Niger Delta are generally believed to be Agbada sand, there exists some finer shale/clay materials deposited along the sandstone. These clay materials have the potential to impart hydrocarbon producibility significantly. [19], has reported that shaliness has an unusual effect on formation characteristics and log response, as well. It is therefore imperative to ensure possible accuracy in estimating this parameter. Three different shale volume relations proposed by different authors were utilized. The Microsoft excel spreadsheet was used to estimate the shale volume from different equations across the subsurface. This platform gives an unusual opportunity to compare and contrast the results across each 0.5 feet.

A. Shale Volume Computation from the Gamma Ray Log.

Determining the linear shale volume from the Gamma Ray (GR) log is one of the best approaches for estimating the shale volume. This is because the procedure involved in the estimation is without any ambiguity and this can produce results for deep reservoirs. Equation (1) projects the definition of an IGR index of shale in terms of the GR log signal. This will only obtain the GR log’s reaction for known neighbouring shale body and clean rocks. It is worthy to say that the linear indicator of shale can overrate the reservoir shale content,

especially young reservoirs of few kilometres which can be termed as shallow. This is because, a careful analysis of such reservoirs will show pessimistic results when compared to other deep producible reservoirs. To solve this problem, many empirical models have been designed to correct and possibly bring down the reservoirs rock's shale contents as direct relation of the IGR. The relation $V_{sh} = f(I_{GR})$ is aimed at making deliberate efforts to minimize the clay constituents and the responses that should have been noticed. This is organized from the pessimistic shallow reservoirs indicators IGR [more volume] to the optimistic deep producible reservoirs. The Larionov shale volume for immature, tertiary rocks [less volume]. Equations (2), (3), (4) and (5) show the linear shale volumes providing the IGR indicator for the [16], equation for ancient/older rocks, the [17], equation for tertiary rocks, the [18], equation for tertiary rocks and the [16], equation meant for tertiary reservoir rocks;

$$GR_{index} = \frac{GR_{log_{signal}} - GR_{clean\ rocks}}{GR_{shale} - GR_{clean\ rocks}} \quad (1)$$

Where GR_{index} = Gamma ray index, $GR_{log_{signal}}$ = Gamma ray reading of the formation, $GR_{clean\ rocks}$ = Minimum gamma ray (clean rock) and GR_{shale} = Maximum gamma ray (shale) reservoirs.

$$V_{shLarionov\ old\ rocks} = 0.33[2^{2.0} - 1.0] \quad (2)$$

$$V_{shClavier\ tertiary\ rocks} = [1.7(3.38 - (I_{GR} - 0.7)^2)]^{1/2} \quad (3)$$

$$V_{shSteiber\ tertiary\ rocks} = \frac{I_{GR}}{3 - (2 \times I_{GR})} \quad (4)$$

$$V_{shLarionov\ tertiary\ rocks} = 0.083[2^{3.7 \times I_{GR}} - 1.0] \quad (5)$$

From (2), (3), (4) and (5), it is imperative that the [16], [17] and [18] models can be employed to determine the shale volume for unconsolidated tertiary deposits and therefore, a merger of the three models is suitable for the shale volume on the same field. A major drawback however will be reservoir intervals that have been relatively consolidated, owing to the huge overburden on it.

B. Determination of Porosity

Porosity is the volume of pore space within reservoir rocks, expressed in percentage. It is the space within reservoir rocks that can harbour liquids (fluids). Porosity can be as a result of earlier existed accumulation of sediments by wind, water or ice. For instance, allowance between rocks that were not completely compacted. This is known as primary porosity. Reservoir rocks can also be porous due to alteration, such as when fossils or feldspar grains underwent preferential dissolution from parent sandstones. Fractures developed on rocks can also cause them to be porous. Effective porosity refers to the linked voids in rocks that give rise to fluid flow

in the reservoir with the exclusion of isolated pores [20]. Total porosity can be said to be the total free space in rocks regardless of its contribution to fluid flow. Thus total porosity is typically greater than the effective porosity. Shale gas reservoirs are usually characterized by high porosity values, but alignment of elongated mineral grains such as clays, contributes to its very low permeability [20]. The reservoir quality is defined by its hydrocarbon storage capacity and deliverability. The effective porosity determines the hydrocarbon storage capacity of the reservoir while the deliverability can be assessed by the permeability. Porosity is a fraction of volume of free space divided by the entire volume. It can either be between 0 and 1, or can be expressed in percentage which ranges from 0 to 100%.

$$\varphi = \frac{V_V}{V_T} \quad (6)$$

Where φ is the porosity, V_V is the void volume and V_T is the total volume.

C. Density Log Derived Porosity

Density log is a type of porosity log that estimates electron density of a distinctive formation. It aids the explorationist to detect zones that are gas-bearing, determine hydrocarbon density, assess shaly sand reservoirs and determine the presence of minerals.

$$\varphi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \quad (7)$$

Where ρ_{ma} = matrix density (ρ_b, ρ_f), (ρ_b = formation's bulk density and ρ_f = formation's fluid density.

Effective porosity was calculated for the evaluating interval using (8).

$$\varphi_e = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} - V_{sh} \left(\frac{\rho_{ma} - \rho_{sh}}{\rho_{ma} - \rho_f} \right) \quad (8)$$

Where ρ_{ma} = matrix density (usually 2.65 g/cc sandstone), ρ_f = formation fluid's density (1.0 gm/cc for water and 0.8 g/cc for hydrocarbon), ρ_b = formation bulk density (obtained from density log at 0.5ft. interval) and ρ_{sh} = density of adjacent shale body.

D. Determination of Permeability

Permeability is the rock's property to transmit fluids. The permeability of a reservoir is a function of its connecting capillaries. It is measured in Darcies or millidarcies. The permeability was estimated using the model proposed by [21]. This model is a function of the porosity and the irreducible water saturation.

$$K_{CD} = 100 \frac{\varphi^2 (1 - S_{wirr})}{S_{wirr}} \quad (9)$$

Where K_{CD} = Coates and Dumanoir Permeability, ϕ = Porosity and S_{wirr} = Irreducible water saturation.

E. Determination of Irreducible Water Saturation

The irreducible water saturation (S_{wirr}) is the fraction of volume of free space occupied by water at highest possible hydrocarbon saturation. The S_{wirr} refers to water that is yet to be dislodged by hydrocarbons because it is housed by clinging to rocks open surfaces, harboured by small cavities, narrow crevices and interstices, etc. [19]. This established a state of balance in the reservoirs. It is different from the residual water saturation which value is obtained by the analysis of core due to filtrate accumulation and expansion of gas that takes place at the time a core is withdrawn from the bottom of the drilled hole to the open surface [19]. The Irreducible water saturation can be estimated using (10):

$$S_{wirr} = \sqrt{\frac{F}{2000}} \tag{10}$$

Where F = Formation factor and S_{wirr} = Irreducible water saturation

The formation factor was determined from the Achie equation below

$$F = \frac{a}{\phi^m} \tag{11}$$

Where ϕ = porosity, a = lithologic constant and m = cementation exponent.

F. Estimation of Shale – Sand Ratio

The shale – sand ratio in hydrocarbon reservoirs is the ratio of the volume of shale to the volume of sand in the reservoir. The percentage of shale is subtracted from 100 to obtain the sand volume. The shale–sand ratio can thereafter be calculated.

$$\%S_v = 100 - \%V_{sh} \tag{12}$$

$$Actual S_v = 1 - V_{sh} \tag{13}$$

$$shale\text{-}sand\ ratio = \frac{V_{sh}}{S_v} \tag{14}$$

G. Estimation of Formation Water Resistivity (R_w)

[22] Established the relationship between the formation factor (F) and the resistivity of rocks when completely filled with water (R_o) using the resistivity of water (R_w). The resistivity of water (R_w) is therefore, the ratio of the resistivity of rocks filled with water (R_o) to the formation factor (F).

$$R_w = \frac{R_o}{F} \tag{15}$$

H. Estimation of Water saturation (S_w)

Water saturation can be estimated from the invaded zone and the flushed zone [23]. The water saturation can be estimated

from the invaded zone (zone invaded by the drilling muds) using (16).

$$S_w = \frac{aR_w}{\phi^m R_t} \tag{16}$$

Where, a and m = saturation exponents ϕ = porosity, R_w = resistivity of water in Ωm and R_t = True resistivity in Ωm .

Water saturation can be estimated from the flushed zone (zone where the formation fluid has been replaced by mud filtrate) as follows;

$$S_{x0} = \left(\frac{FR_{mf}}{R_{x0}}\right)^{0.5} \tag{17}$$

$$S_w = \sqrt[5]{S_{x0}} \tag{18}$$

Where S_{x0} = saturation of invaded zone, F = formation factor, R_{mf} = mud filtrate resistivity in Ωm , R_{x0} = invaded zone resistivity in Ωm and S_w = water saturation.

The water saturation can also be estimated using the relationship between the resistivity of rocks filled with water and the true resistivity [23]. The true resistivity is the resistivity of rocks filled with water and oil.

$$S_w = \left(\frac{R_o}{R_t}\right)^{1/N} \tag{19}$$

Where S_w = water saturation, R_o = resistivity of rocks filled with water in Ωm , R_t = true resistivity in Ωm and N = saturation exponent.

I. Estimation of Hydrocarbon Saturation (S_h)

The hydrocarbon saturation can simply be estimated by subtracting the value for the water saturation from 1. Thus, the sum of the water and hydrocarbon saturation gives 1 [24].

$$S_h = 1 - S_w \tag{20}$$

Where S_h = Hydrocarbon Saturation and S_w = Water saturation.

J. Estimation of True Conductivity (C_t)

Conductivity is the reciprocal of resistivity. A very high conductivity in a formation suggests that more volume of water is dissolved in the reservoir rocks and because of the constituent mineral elements, the rocks therefore become salty. A low conductivity, indicates a high resistivity which indicates the presence of more hydrocarbon in the formation [25].

$$C_t = \frac{1}{R_t} \tag{21}$$

Where C_t = true Conductivity in Per Ohm-meter and R_t = true resistivity in Ohm-meter.

K. Estimation of the Bulk Volume Water (BVW)

The bulk volume water can be estimated by simply multiplying the water saturation and the porosity. The BVW is determined at different depths in a given formation and its values are constants or almost constants [26]. BVW is a pointer to the fact that the zone has a uniform composition at S_{wirr} .

$$BVW = S_w \varphi \quad (22)$$

Where BVW = Bulk Volume water, S_w = Water Saturation and φ = Porosity.

L. Gross thickness (GT) of reservoirs

The gross thickness of reservoirs is the interval between the tops and bottom (base) of the reservoirs. It is expressed in meters or feet.

$$GT = RSV \text{ top depth} - RSV \text{ bottom depth} \quad (23)$$

Where GT = gross thickness in m or ft , $RSV \text{ top depth}$ = depth of reservoir's top and $RSV \text{ bottom depth}$ = depth of reservoir's bottom.

M. Well Logging

The demand for an improved recovery of hydrocarbon from the subsurface has called for a tremendous advancement in technology in the industrial sectors of the world [27]. This has led several experts in the field of Physics, Chemistry, Geophysics, Geology, and Petrophysics to come together and brainstorm, in order to devise better means of exploring hydrocarbon from sedimentary strata which are capable of housing water and hydrocarbon. This was with a view to expanding the business of oil in the world [28].

Logs are bi-dimensional graphs revealing several characteristics of parameters in Petrophysics as the depth increases [29]. A very common example of well logs is the lithology logs

The lithology logs target the measurement of the types of rock present in the exploration boreholes. Some examples of lithology logs are (1) Gamma Ray log (2) Spontaneous Potential log (3) Resistivity log (4) Deep induction log and (5) Porosity Log.

1) Gamma ray (GR) log

One major petrophysical parameter is the lithology [30]. This can best be determined using radioactive rocks. Radioactive elements such as radium, radon, potassium, uranium and thorium occur naturally and contained important minerals useful for petrophysical interpretations. The relationship between different types of rocks and the intensity of gamma ray does not exist but isotope size in radioactivity

has a close relationship with minerals exploration. The lithology can be determined by detecting the gamma rays produced by the naturally occurring radioactive elements of the formation [31]. The shale volume in sedimentary strata is revealed by the GR log. This is because shale possesses very high radioactive characteristics while clean formations possess very low radioactive characteristics [32]. Naturally occurring radioactive elements are rich in calcium carbonate and silicon dioxide. Analysis of logs using the GR log can be done by first considering a simple relation for estimating the gamma ray content.

$$\gamma = \sum_i V_i \gamma_i \quad (24)$$

This can be simplified to determine the shale content of the formation

$$\gamma = V_{sh} \gamma_{sh} + V_{ma} \gamma_{ma} + V_f \gamma_f \quad (25)$$

Where γ_{sh} = Gamma ray content in shale, γ_{ma} = Gamma ray content of the rocks' minerals, γ_f = Gamma ray content of the formation, V_{sh} = Volume of shale, V_{ma} = volume of minerals and V_f = volume of formation.

A further simplification of the formula to accommodate the volume of fluid and porosity will give:

$$\gamma = V_{sh} \gamma_{sh} + V_{cn} \gamma_{cn} \quad (26)$$

Where γ_{cn} = Gamma ray content of clean rocks and V_{cn} = Volume of clean rocks.

When a closure is added to (26), it gives:

$$V_{sh} + V_{ma} = 1 \quad (27)$$

Equation (27) can be re-simplified to produce the usual relation for estimating the volume of shale.

$$V_{sh} = \frac{(\gamma_{log} - \gamma_{cn})}{(\gamma_{sh} - \gamma_{cn})} \quad (28)$$

2) Spontaneous Potential log

This log measures the naturally occurring potential difference when the filtrate from the mud of a particular salt content invades another formation housing water of unmatched salinity. This lithology log is only viable in boreholes containing water. Where the salt content of the water in the formation and that in the filtrate from the mud are almost the same, the spontaneous potential log will not be very effective as it will produce a small deflection [33].

3) Resistivity log

This measures the opposition of the formation to the flow of electric current. The rocks on their own cannot conduct electricity. Rocks ability to allow the flow of electric current is determined by the water content in the pores. Hydrocarbon does not conduct electricity. When a reservoir rock records high hydrocarbon saturation, it means that the resistivity of the reservoir is high. A high water saturation is an indication of high conductivity [34]. Fig. 3 depicts some of the important well logs utilized for adequate petrophysical evaluation in Green field.

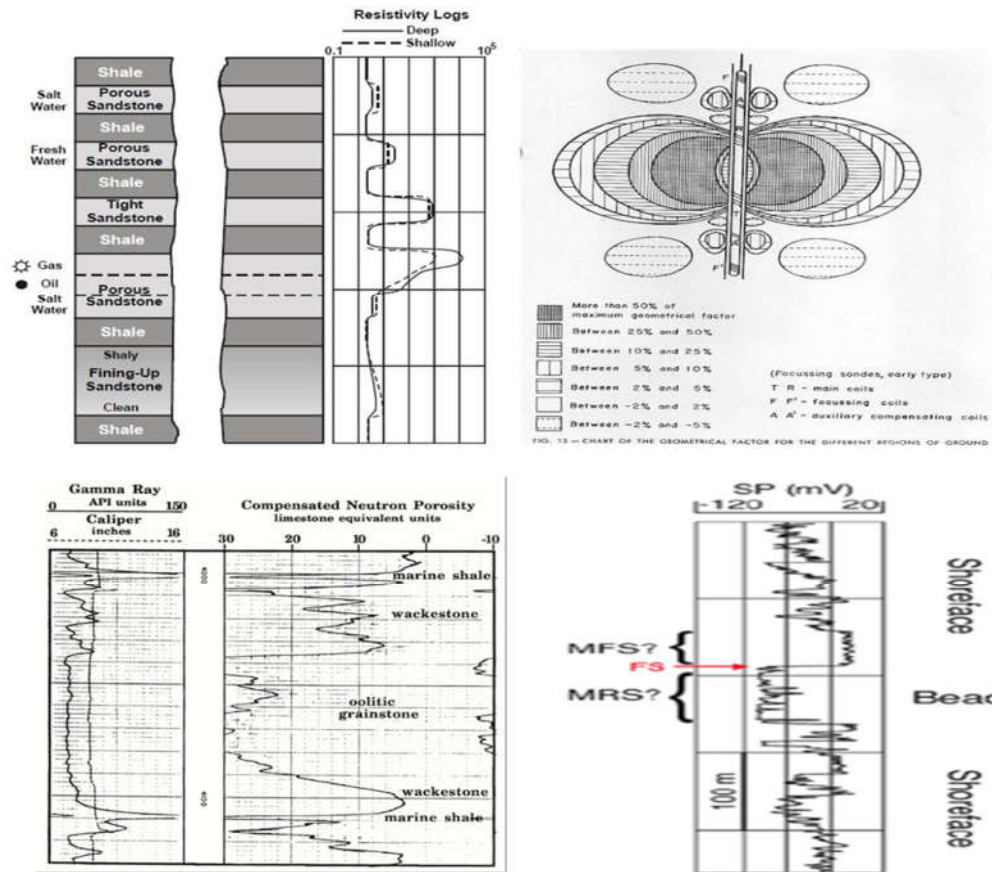


Fig. 3 Images of important well logs considered in the research work [31].

4) Deep Induction Log

This measures the resistivity of mud rich in oil in an exploration borehole. This is because the muds do not conduct and there is a need to pay attention to the current so as to reduce the impact of the exploration holes and the nearby formations. The deep interpretation and minimization of the

effects of the zones affected by the mud (invaded zones) are carried out by this log. Sonde used for deep induction logging has two main coils, the receiver and the transmitter coils. These are contained in an insulating glass and a fixed current is supplied to the transmitter by an oscillator [35]. Fig. 4 shows the physical features of the transmitter and receiver coils of the deep induction log equipment.

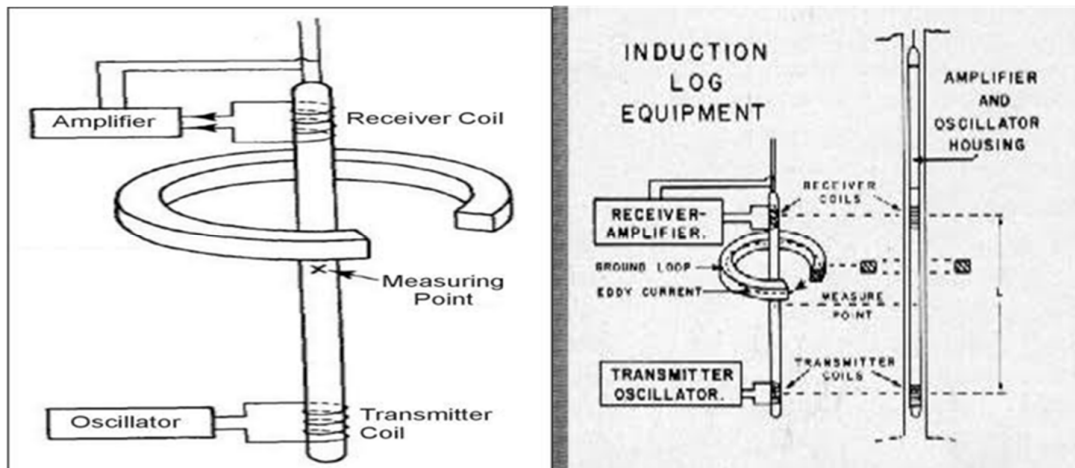


Fig. 4 Deep induction log equipment showing the transmitter and the receiver coils [31].

5) Porosity log

This type of log deals with the measurement of the ratio of the pores to the total volume of rocks. It is made up of the density, sonic and neutron logs. The porosity log seeks to compare the space (allowance) within rocks to the total volume of rocks in a formation [36].

V. RESULTS AND DISCUSSION

Five reservoir intervals, denoted as *RSV A*, *RSV B*, *RSV C*, *RSV D* and *RSV E* were identified in all the wells studied from the Green Field (Table 1) *RSV A*, mapped across the three wells penetrated gross thickness of 639.500ft (194.920 m), 508.334 ft (154.940 m) and 601.500 ft (183.337 m) for Green 1, Green 2 and Green 3 wells respectively. Similarly, the *RSV B* reservoirs (measured in feet and metres) were measured to be 390.000 (118.872), 480.167 (146.359) and 454.000 (138.379) in sequential order across the wells. *RSV C* in Green 2 was observed to be the thinnest of the fifteen (15) delineated reservoirs with gross thickness value of 281 ft. Conversely, the highest gross thickness is from *RSV A* in Green 1. Thickness of candidate reservoirs is one of the major factors for consideration in taking developmental decisions; a thorough look at the reservoirs mapped out in the Green field shows that the recorded thicknesses are reasonably sufficient for development, provided adequate hydrocarbon saturation is found within the pore spaces.

Table I: Delineated reservoirs and estimated gross thickness across the green wells

RSV A	TOP (Ft, m)	4614.000 (1406.707)	4599.500 (1402.287)	4658.000 (1420.122)
	BASE (Ft, m)	5253.500 (1601.667)	6107.834 (1862.145)	5259.500 (1603.094)
	GT (Ft, m)	0639.500 (0194.970)	0508.834 (0155.132)	0601.500 (0183.384)
RSV B	TOP (Ft, m)	5551.500 (1692.097)	5609.500 (1709.776)	5282.750 (1610.182)
	BASE (Ft, m)	5941.500 (1810.989)	6089.667 (1856.606)	5736.750 (1748.561)
	GT (Ft, m)	0390.000 (0118.872)	0480.167 (0146.389)	0454.000 (0138.379)
RSV C	TOP (Ft, m)	6386.500 (1946.605)	6389.667 (1947.571)	5776.250 (1760.601)
	BASE (Ft, m)	6854.500 (2089.252)	6670.667 (2033.219)	6256.750 (1907.057)
	GT (Ft, m)	0468.000 (0142.646)	0281.000 (0085.649)	0480.500 (0146.456)
RSV D	TOP (Ft, m)	7102.000 (2164.690)	6698.667 (2041.754)	6300.250 (1920.316)
	BASE (Ft, m)	7399.500 (2255.368)	7010.667 (2136.851)	6785.000 (2068.068)
	GT (Ft, m)	0279.500 (0090.698)	0312.000 (0095.098)	0484.750 (0147.752)
RSV E	TOP (Ft, m)	7557.000 (2303.374)	7037.334 (2144.979)	6820.250 (2078.812)
	BASE (Ft, m)	7909.000 (2410.663)	7435.834 (2266.442)	7131.500 (2173.681)
	GT (Ft, m)	0352.000 (0107.290)	0398.500 (0121.371)	0311.250 (0094.869)

A. Deductions from qualitative analyses

Results of the lithologic-based reservoir correlation carried out, as well as the fluid identification, based on the signature of resistivity logs and interaction between the neutron-density cross-plots. Fig. 5 and 6 further support the fact that the reservoirs are correlatable as well as hydrocarbon bearing. Presence of oil was observed in all the reservoirs identified, although their saturation obtained from the Archie's equation as (0.154, 0.473, 0.136, 0.213 and 0.466 *v/v* for Green 1), (0.022, 0.076, 0.064, 0.188 and 19.780 *v/v* for Green 2) and (0.583, 0.722, 0.682, 0.868 and 0.888 *v/v* for Green 3) varied apart.

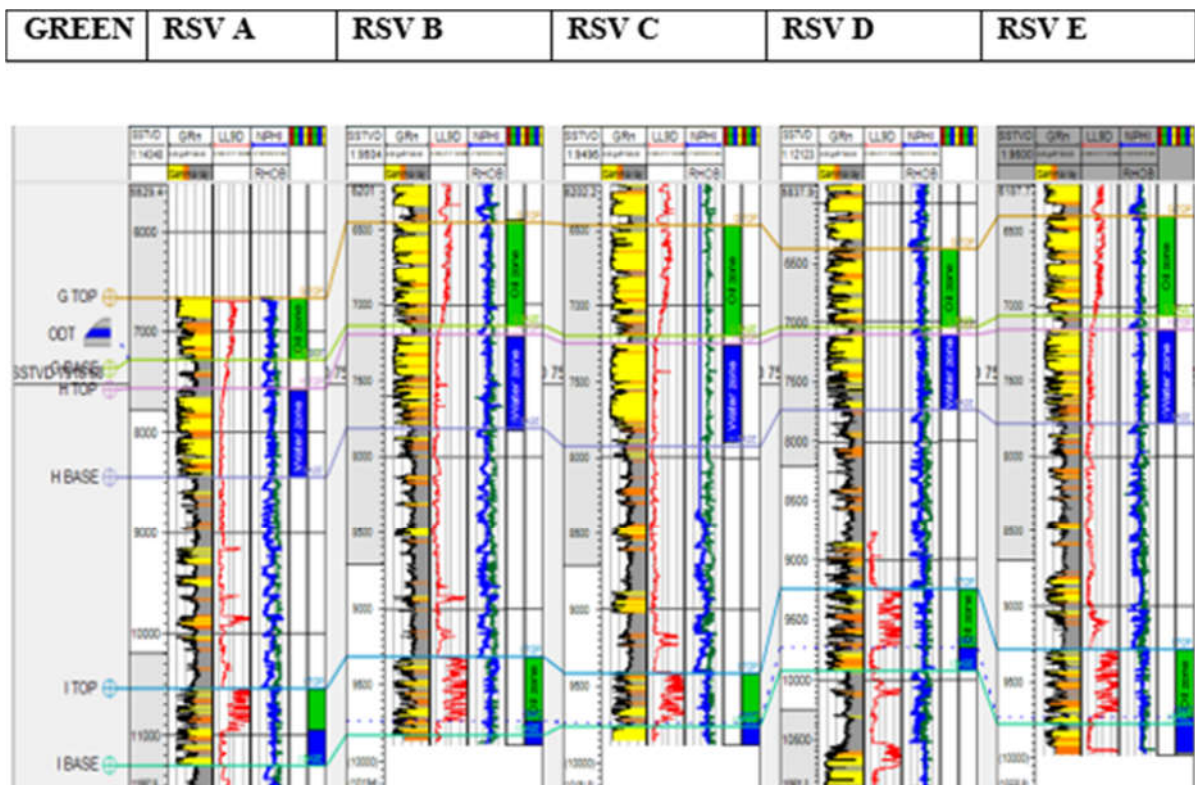


Fig. 5 Fluid identification and correlation across reservoirs (Obtained from PETREL version 2010® and OpendTect® Softwares)

Fig. 5 shows the tops, bottoms and the interval of the Green wells correlated with the PETREL version 2010 and the OpendTect® exploration softwares. The Microsoft excel 2015® was employed to estimate the gross thickness (GT) with the mathematical algorithm explained in equation (24) to obtain quantitatively analysed values on Table I for RSV A, RSV B, RSV C, RSV D and RSV E.

B. Demarcation between sandstones and shale

The first and most important stage of petrophysical evaluation is to identify lithology [5]. This is as a result of the connection between the inherent rocks and the oil, gas and water contents [22]. Lithology identification was enhanced by first converting the digital data obtained to analog form, that can easily be understood and relate with. The dataset was imported into the petrel environment. A shale base line established at 70° API, was used to demarcate between sandstone and shale in sequences penetrated by the well. The logs were thereafter reorganized to enhance their suitability in obtaining the needed geophysical parameters. From the correlated Green reservoirs (Fig. 5), intervals identified as sandstones were painted green, while their shale counterparts

were marked white. Water zones intervals were painted blue while intervals that appear red in Fig. 5 represent intervals with null values, which were removed to avoid errors.

C. Reservoir identification

The Gamma ray (GR) log was utilized in the detection of the shale/sand lithologic evaluation, the GR log measures natural radioactivity in formation. The gamma ray log is an appropriate tool used to decipher between reservoir and non-reservoir. Owing to the accumulation of radioactive constituents in shale, GR reaction increases while the absence or low concentration of radioactive constituents in sand produces a decrease in the GR response. Consequently, a complete deflection to the right-hand-side of a GR log is a sign of the existence of shale while an incomplete deflection to the left-hand-side reveals the presence of sand. The sand intervals were further screened for suitability as potential reservoirs using the signatures of the porosity logs and the resistivity logs. Sand intervals, where marked neutron-density crossover occurred alongside reasonable high resistivity values, were screened as potential reservoirs. Fig. 6 shows suite of wireline logs and generated lithologies from the study area.

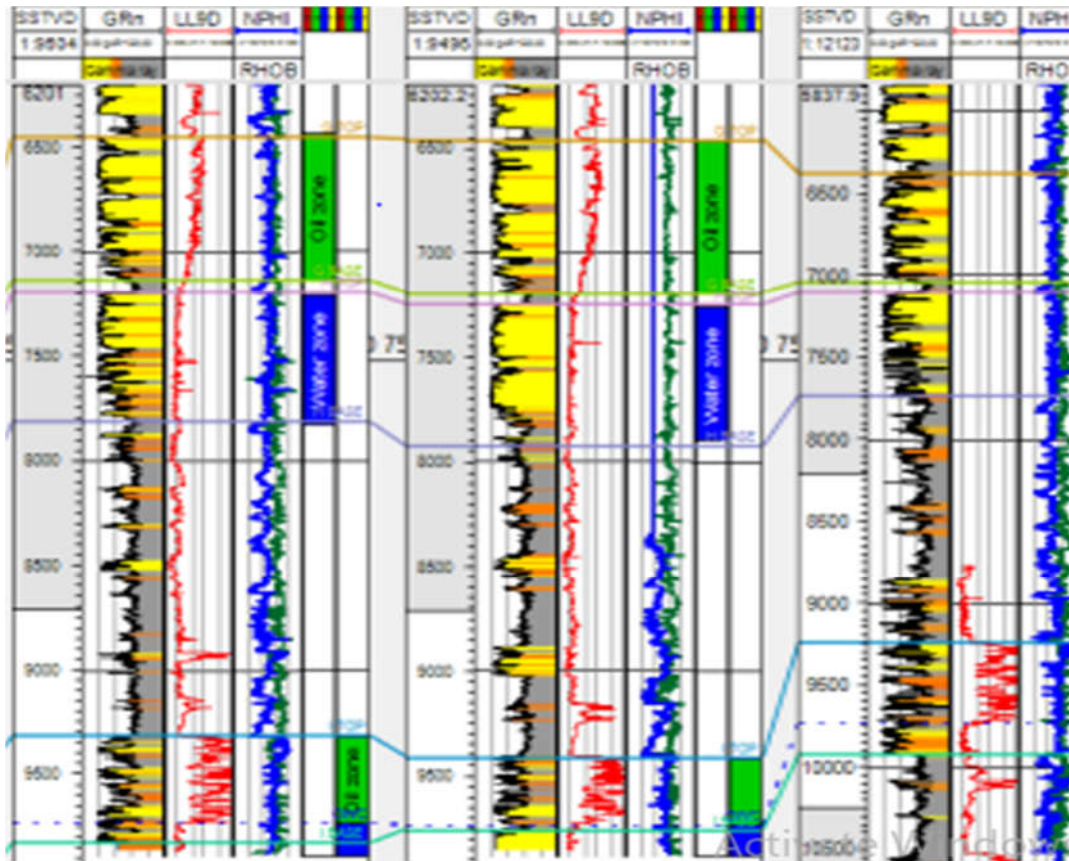


Fig. 6 Suites of wireline logs and generated lithologies from the Green Field (Obtained from PETREL version 2010 and OpendTect Softwares)

D. Reservoir Fluids Identifications

The compensated formation density and the neutron logs were utilized for distinguishing the different fluid types. A gas bearing zone may experience a boost in the density porosity alongside a fall in the neutron porosity. This, when it happens is known as gas effect. Gas effect is originated from gas in the cavities. Gas occupying the cavities gives rise to high porosity values recorded by the density log. This is because gas is less dense than water or oil. On the other hand, gas in the cavities can make the neutron log record low porosity values because of the low concentration of hydrogen atom in gas when compared to water or oil [5]. Consequently, an increased contrast between $\varphi_{density}$ and $\varphi_{neutron}$ logs is indicative of a gas-bearing zone, while a decreased contrast between $\varphi_{density}$ and $\varphi_{neutron}$ logs is a pointer to a water or oil-bearing zone. A merger of the neutron-density logs can therefore be regarded as a reliable tool that can be employed to distinguish between water, oil and gas. The reservoir identified to be hydrocarbon-bearing were further analysed petrophysically, first by estimating shale volume using diverse relations and the permeability using the Coates and Dumanoir's relation. Since the estimation of permeability depends on porosity, porosity was also estimated before the permeability.

E. Quantitative Analysis of Reservoir Shale Volumes (V_{sh})

Tables V, VI and VII present the average shale volumes obtained in the analysed reservoirs using the [16], [17] and [18] relations. Generally, shale volume is observed to increase with depth in the Green field. This agrees with the work of [23], who described the order and relative position of strata of the Niger Delta in detail. The authors described the Agbada Formation as intercalations of shale and sands; and shaliness increases downward into the Akata Formation, which is essentially shale. The large nature of data used for the study did not permit documentation of shale volume values across each evaluated intervals. As a result, the mean shale from each equation across the delineated reservoirs are documented in the tables. Taking clue from Table V, the $V_{sh\ Clavier}$ recorded the highest values when compared to the other two methods across the reservoirs in Green 1 well. Conversely, the $V_{sh\ Larionov}$ was observed to be the least in all the delineated reservoirs of well 1. Carefully comparison of results obtained from the shale volume equation shows that the Clavier relation and the Larionov relation were marked with difference as high as 6% shale volume, in favour of Clavier.

Although this range looks insignificant, since it falls below the 15% V_{sh} cut off for hydrocarbon reservoir, it is noteworthy to state that such error margin can significantly mislead the reservoir geoscientist to either overrate a reservoir or pessimistically evaluate a potential hydrocarbon sands. The Steiber equation is observed to give results that are very similar to Clavier equation, although some disagreements still exist in the shale volume obtained from them, with the latter recording higher V_{sh} than the former (Table V). Similar trend

as this was observed in the Green 2 and Green 3 wells. Details of this shale volumes obtained for this well are presented in Tables VI and VII. [24], has opined that the same petrophysical parameters obtained by several methods from the same rock unit can be treated by using the least value obtained. The challenge with this approach is the ambiguity involved in such decision; as the least value obtained can actually be the wrong one, thus confusing the log analyst to underestimate the reservoir shale. Statistically, mean is the average of a set of numbers. It is a measurement of central tendency. This implies that it provides true representation of all the samples in a particular set. The average V_{sh} in Tables V, VI and VII represents better quantity of shale in hydrocarbon reservoir, since it integrates the strengths of the three (3) methods used, and also mitigates their weaknesses.

F. Quantitative Analysis of Reservoir Permeability (K)

The Coates and Dumanoir permeability estimation model was used to estimate the reservoir permeability. It yielded values that ranged from 86717.0 to 2955.2 mD and 3529.742 to 640.5 mD respectively. Generally, permeability in the Green 1 well is observed to decrease with depth. This may not be connected with close grain packing owing to overburden load. The irregularities noticed in the value of permeability across the three wells may be due to certain reservoir heterogeneities masking through the permeability [1].

G. Discussion of Porosity (φ)

Mean density porosity obtained in the reservoirs of Green 1 well is 0.3160, 0.2770, 0.2710, 0.2610 and 0.2690 for RSV A, RSV B, RSV C, RSV D and RSV E respectively. These strongly suggest moderate porosity in the reservoir sands. The values of effective porosity however reduced with noticeable discrepancies. Reservoirs RSV A, RSV B, RSV C, RSV D and RSV recorded values (measured v/v) of 0.289, 0.252, 0.236, 0.234 and 0.237 respectively. The differences observed between the density porosity and the effective porosity is interpreted to be micro-porosity contributions from shale. Similar trend to this is also observed in the Green 2 and Green 3. Tables (VI and VII) respectively.

H. Comparison of Sand to Shale in the Reservoirs

The volume of shale in all the fifteen reservoirs were subtracted from the total volume of both sand and shale. This is to determine the volume of sand and thereafter, determine the true resistivity and conductivity in order to arrive at values for water and hydrocarbon saturation. Green 1 recorded 0.111: 0.889, 0.116: 0.884, 0.162: 0.838, 0.132: 0.868 and 0.153: 0.847 shale to sand ratios for all the five mapped out reservoirs. The Green 2 well recorded, 0.056: 0.944, 0.078: 0.922, 0.069: 0.931, 0.092: 0.908 and 0.091: 0.909 while the Green 3 reservoirs recorded shale to sand ratios of 0.007: 0.993, 0.100: 0.900, 0.120: 0.991, 0.130: 0.987 and 0.140: 0.986. Comparison of the volume of shale and

sand in each of the fifteen reservoirs showed that sands are more in volume than shale in the Green reservoirs. This may not out rightly suggest the presence of hydrocarbon because nature of fluid housed by the sand is the real indicator of the hydrocarbon prospectivity of the field [37].

I. True Resistivity and Conductivity

The true resistivity of the formation showed that almost all the fifteen reservoirs have high hydrocarbon prospectivity. A high resistivity is an indication of high potential of hydrocarbon [38]. The conductivity of the formation revealed that the reservoir rocks housed small percentage of water. This can also mean that the reservoirs are filled up with porous and permeable rocks which allowed the passage of hydrocarbons [39]. Comparison of the true resistivity and conductivity is necessary as Fig. 9 gives a clearer picture of the nature of fluids present in the reservoirs. High resistivity indicates a high percentage of HC while high conductivity indicates high water saturation. Low resistivity indicates low percentage of HC while low conductivity, this also indicates low water saturation.

J. Gross Thickness of Green Wells

The Gross thickness refers to the thickness of the intervals of well defined by the stratigraphy from which the beds of the reservoirs have occurred. This comprises the intervals that are not rich in hydrocarbon because intervals that are not productive may be situated in layers between the productive ones [40].

K. Quantitative Evaluation of Reservoir Parameters

The data analysed with the PETREL version 2010 and OpendTect exploration softwares were loaded into the Microsoft excel 2015 environment of the computer. Mathematical algorithms explained in (11), (15), (21), (22) and (24) were used to estimate the parameters ($F, R_w, R_o, S_w, S_h, R_t, C_t$ and GT) shown on Tables II, III and IV and (2), (3), (4), (5), (8), (9), (13) and (14) were used to estimate the parameters ($S_v, V_{sh}, S_v/V_{sh}$ and ϕ_T) shown on Tables V, VI and VII.

Table II: Formation factor, Water Resistivity, Saturated Rock Resistivity, Water Saturation, HC saturation, True Resistivity and Conductivity and the Gross Thickness for Green 1 Reservoirs

F	$R_w(\Omega m)$	$R_o(\Omega m)$	$S_w(v/v)$	$S_h(v/v)$	$R_t(\Omega m)$	$C_t(\Omega m)^{-1}$	GT (m)
16.593	1.490	24.72	0.505	0.495	96.93	0.01	194.970
17.412	1.567	27.28	0.795	0.205	43.16	0.02	118.872
21.269	0.191	04.06	0.461	0.539	19.10	0.05	142.646
21.946	0.197	04.32	0.564	0.436	13.58	0.07	90.678
21.081	0.189	03.98	0.842	0.158	05.61	0.18	107.290

Table III: Formation factor, Water Resistivity, Saturated Rock Resistivity, Water Saturation, HC saturation, True Resistivity and Conductivity and the Gross Thickness for Green 2 Reservoirs

F	$R_w(\Omega m)$	$R_o(\Omega m)$	$S_w(v/v)$	$S_h(v/v)$	$R_t(\Omega m)$	$C_t(\Omega m)^{-1}$	GT (m)
18.895	0.151	2.85	0.166	0.834	103.42	0.00967	155.132
20.334	0.162	3.29	0.305	0.695	35.37	0.02828	146.389
21.013	0.168	3.53	0.271	0.729	48.07	0.02080	085.649
29.138	0.233	6.79	0.532	0.468	23.99	0.04168	095.098
30.142	0.323	9.74	0.780	0.220	16.01	0.06246	121.371

Table IV: Formation factor, Water Resistivity, Saturated Rock Resistivity, Water Saturation, HC saturation, True Resistivity and Conductivity and the Gross Thickness for Green 3 Reservoirs

F	$R_w(\Omega m)$	$R_o(\Omega m)$	$S_w(v/v)$	$S_h(v/v)$	$R_t(\Omega m)$	$C_t(\Omega m)^{-1}$	GT (m)
13.439	0.941	12.64	0.781	0.219	20.72	0.048	183.384
17.453	1.221	21.31	0.980	0.020	22.19	0.045	138.379
13.946	0.976	13.61	0.848	0.152	18.93	0.053	146.456
14.941	1.311	19.59	0.987	0.013	20.11	0.050	147.752
13.955	0.976	13.62	0.961	0.039	14.75	0.068	094.869

Table V: Shale Volumes, Porosity, Shale – Sand Ratio and Permeability Values Obtained for Green 1 Reservoirs

Reservoirs	Volume of Sand (S_v)	V_{sh}	Shale – Sand Ratio	Total Porosity ϕ_T (v/v)	Coates and Dumanoir K (K_{CD})
RSV A	0.889	0.111	0.125	0.316	3529.742
RSV B	0.884	0.116	0.131	0.277	0979.819
RSV C	0.838	0.162	0.193	0.271	1183.889
RSV D	0.868	0.132	0.152	0.261	0654.461
RSV E	0.847	0.153	0.181	0.269	0640.456

The five reservoirs in Green 1 well have permeability values increasing with decrease in the shale volume except for RSV C which behaved in a different way. This can be as a result of some certain clay heterogeneities masking through the permeability. [1], opined that low permeability in reservoirs may be due to clay heterogeneities masking the permeable rocks of the reservoir. Fig. 7(a) shows a probable behavior of masked permeability. It can also be that RSV C contains some quantity of laminated shale deposits. The shale type in that reservoir also determines the permeability. However, a porous reservoir rock should have a high permeability as shown in Fig. 7 (b). RSV A and D did not follow the same trend. This as well, may be due to some certain shale type deposits in the reservoirs. Nevertheless, one can say that Green 1 well is producible.

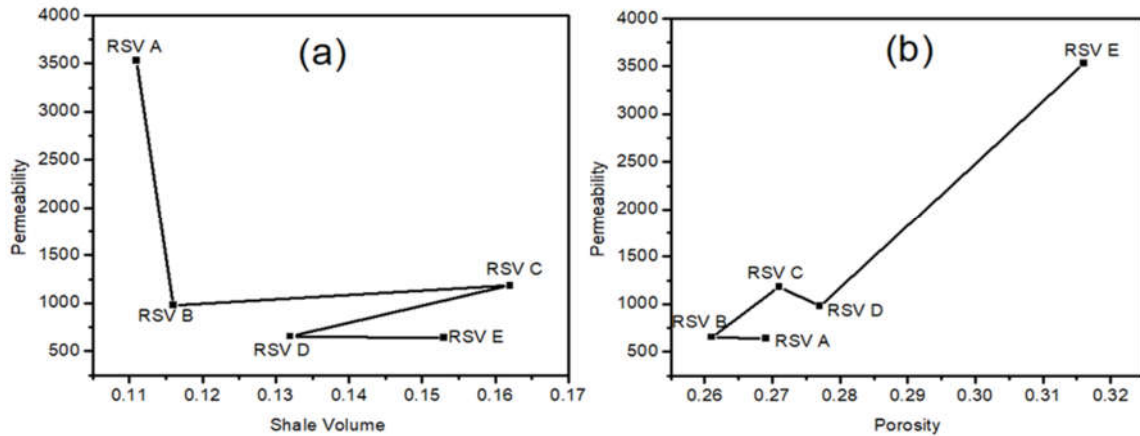


Fig. 7 (a) Relationship between Permeability and Shale Volume, and (b) Variation of Permeability with the porosity in Green 1 reservoirs (Values Obtained from Table V).

Fig. 8 shows the extent to which sand and shale are accumulated in the Green wells. All the Green reservoirs have higher volume of sand than shale. This does not suggest the presence of hydrocarbon, as the type of fluid harbored in the sand and shale determines hydrocarbon prospectivity of the field. However, low shale volume in all the fifteen reservoirs can serve as a pointer to a probable high permeability and porosity. This is because the shale in the Green reservoirs are all fractured. The space between the shale deposits of the reservoirs allows easy movability of hydrocarbon [41]. Results obtained from the work of [41], shows similar trend with the findings of this research. However, [41], focused on the gross and net thickness of the reservoirs sand, in order to determine the behavioral trend of sand in the identified wells. This however, revealed the volume of shale in each of the reservoirs. Depositional forms of the reservoir shale was discovered to have caused the differences in V_{sh} across the study area. The porosity of the area studied by [41], was discovered to be good, as there were faults creating pores for easy movability of hydrocarbon.

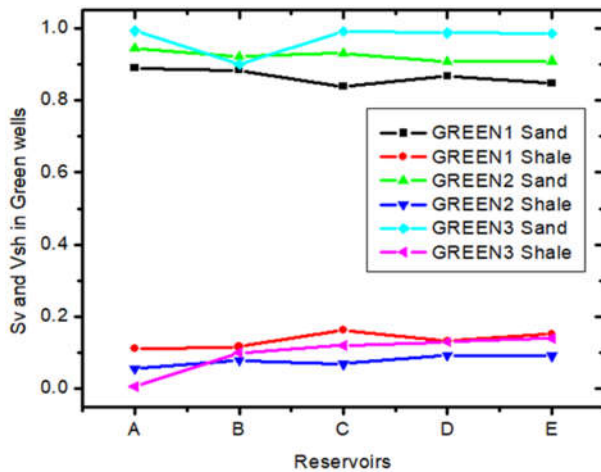


Fig. 8 Comparison of V_{sh} and S_v in the Green Wells (Values Obtained from Tables V, VI and VII)

The true resistivity (resistivity of rocks containing water and oil) for all the reservoirs is higher than the conductivity. This can only mean that the hydrocarbon potential of the Green field is high. As it is established that the Green reservoirs are high in volume of sand (Fig. 8). A higher resistivity than conductivity indicates the presence of high volume of hydrocarbon being housed by the reservoir sand [42]. Hydrocarbons are organic compound which do not dissociate to conduct electricity. This is why they are characterized by low conductivity and high resistivity. Nevertheless, water also exist in the Green reservoirs but in a very small percentage. A low conductivity for all the Green wells implies that a very small percentage of water is contained in the rocks and dissolution of the rocks constituent minerals actually led to dissociation into ions. This produces a small conducting ability as observed in Fig. 9.

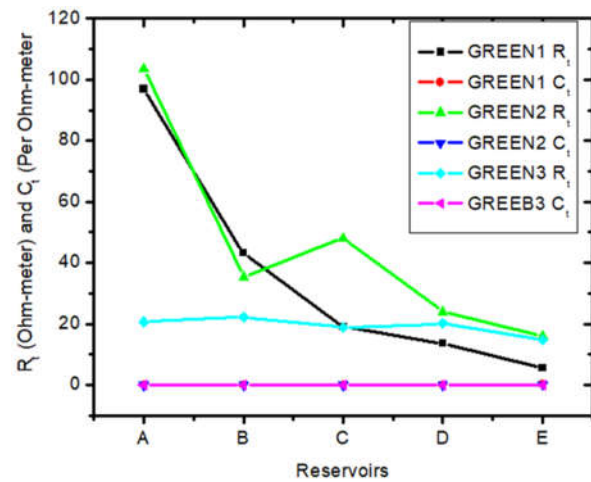


Fig. 9 Comparison of Resistivity and Conductivity in the Green Wells (Values Obtained from Tables II, III and IV)

Work done on resistivity in this research work is similar to the work of [42], where the resistivity of the formation in six

different reservoirs were determined and compared with the percentage water and hydrocarbon saturation. Reference [42], however concluded that the formation resistivity of the reservoir rocks has a direct variation with the hydrocarbon saturation.

The gross thickness of the Green wells does not determine the hydrocarbon potential. This is shown in the haphazard behavior of Green 1, 2 and 3 (see Fig. 10 (a), (b) and (c)). Petrophysically, the gross thickness encompasses both the productive and the non-productive regions in layers. The productive regions guarantee high resistivity which translates to a high hydrocarbon potential. The non-productive layers

indicate high conductivity which translates to reservoir rocks containing water which dissolved its minerals. The net thickness is achieved by removing the non-hydrocarbon producing regions. The net thickness (which is the thickness of the hydrocarbon bearing layer) can turn out to produce high hydrocarbon deposits only when the productive layers have high contents of hydrocarbon [43]. The result obtained from the gross thickness is in line with the work of [43]. Different from what was considered in this research, [43], looked at the thickness of only the hydrocarbon rich layers which is basically the net thickness of the wells, so as to determine the gas zones.

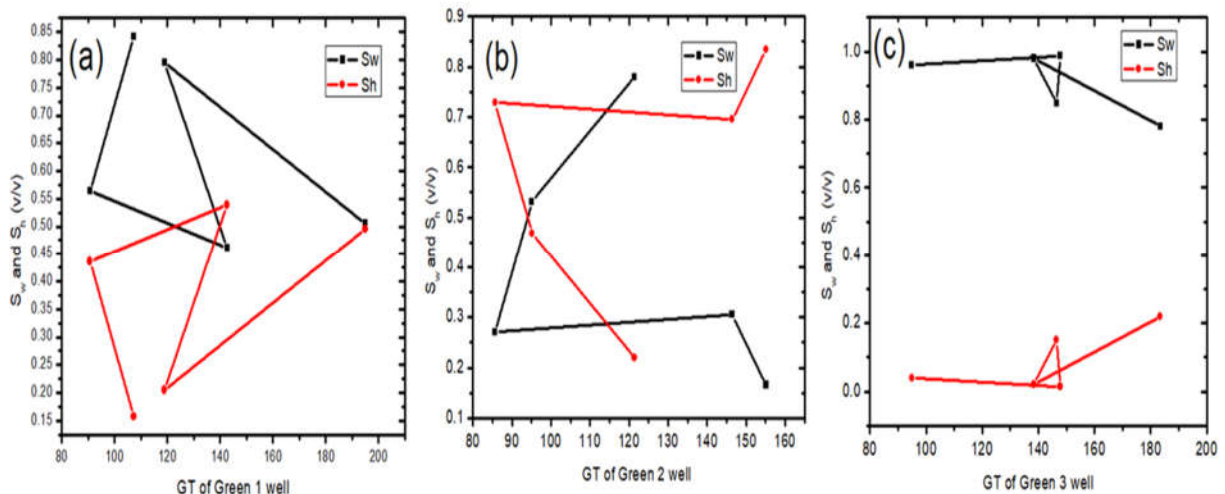


Fig. 10 (a, b and c): Comparison of the S_w and S_h with the Gross thickness (GT) in the Green Wells 1, 2 and 3 (Values Obtained from Tables II, III and IV)

In Green 2 well, two reservoirs RSV B and RSV D have permeability values slightly decreasing as against what is expected (Fig. 11(a)). These discrepancies may be due to reasons earlier stated above. The permeability in the same well however increases with increase in the porosity (Fig. 11b). One can say that, there are porous reservoir rocks in Green 2 well.

Table VI: Shale Volumes, Porosity, Shale – Sand Ratio and Permeability Values Obtained for Green 2 Reservoirs

Reservoirs	Volume of Sand (S_v)	V_{sh}	Shale-Sand Ratio	Total Porosity ϕ_T (v/v)	Coates and Dumanoir $K(K_{CD})$
RSV A	0.944	0.056	0.059	0.256	71.716
RSV B	0.922	0.078	0.085	0.246	56.940
RSV C	0.931	0.069	0.074	0.234	45.814
RSV D	0.908	0.092	0.101	0.227	42.829
RSV E	0.909	0.091	0.100	0.219	37.746

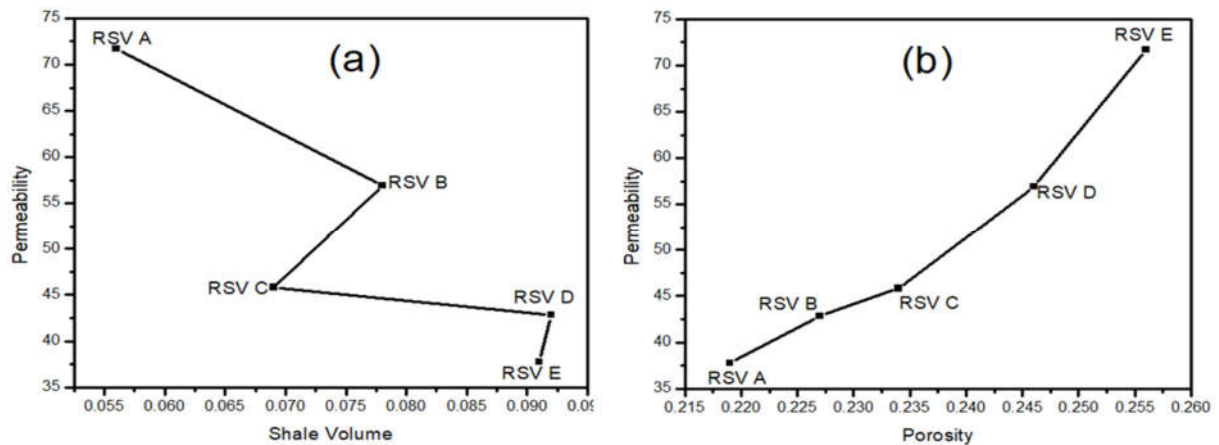


Fig. 11 (a) Relationship between Permeability and Shale Volume and, (b) Variation of Permeability with the porosity in Green 2 reservoirs (Values Obtained from Table VI)

Fig. 12 (a) and (b) show that the five reservoirs of Green 3, RSV A, RSV B, RSV C, RSV D and RSV E all experienced gradual increase in the permeability as the shale volume decreases. The permeability showed the normal trend of increase with increase in the porosity. It is worthy to say that, Green 3 well has fractured shale which gave rise to high permeability. On the average, the Green wells have shown high prospect of hydrocarbon. This is similar to the work of [44], where the ratio of the gross to the net thickness was determined across the reservoirs. The water saturation was thereafter compared with the porosity in order to determine the BVW and S_{wirr} .

Table VII: Shale Volumes, Porosity, Shale – Sand Ratio and Permeability Values Obtained for Green 3 Reservoirs

Reservoirs	Volume of Sand (S_v)	V_{sh}	Shale-Sand Ratio	Total Porosity ϕ_T (v/v)	Coates and Dumanoir $K(K_{CD})$
RSV A	0.993	0.007	0.00705	0.279	9143.295
RSV B	0.900	0.100	0.11111	0.276	8620.817
RSV C	0.991	0.120	0.00908	0.275	8575.385
RSV D	0.987	0.130	0.01317	0.274	8085.388
RSV E	0.986	0.140	0.01420	0.273	7865.795

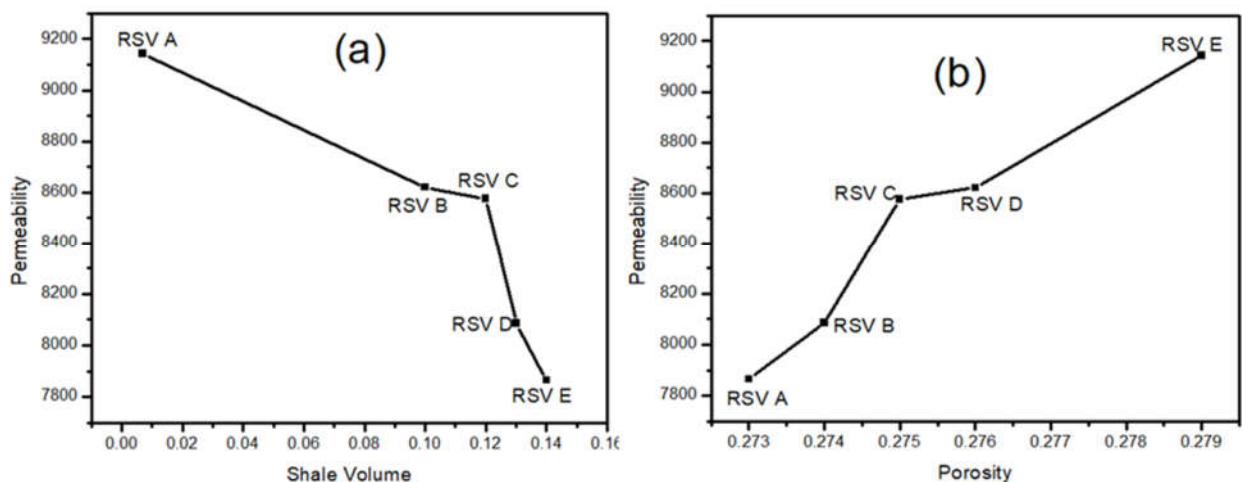


Fig. 12 (a) Relationship between Permeability and Shale Volume and, (b) Variation of Permeability with the porosity in Green 3 reservoirs (Values Obtained from Table VII)

VI. CONCLUSION

Fifteen reservoirs were mapped and correlated across the Green field. Though these reservoirs vary in thickness across field, they are thick enough to be considered for further developmental action. Minor shale intercalations which have

the potential to impede fluid flow exist in the reservoirs. All the reservoirs delineated were observed to have presence of oil, although water occurs alongside the oil. Some intervals only recorded minor shows of oil, as water saturation values increase in Green 3. Oil distribution across the Green field

decreases as one traverses from the eastern part of the field to the west. No gas was discovered in the Green field.

Careful comparison of the Larionov equation, Clavier equation, Steiber equation and the mean shale volume relation shows that the Steiber equation closely agrees with the average V_{sh} values. Based on the findings of this study, the Steiber method for estimating V_{sh} is preferred above its other two counterparts; nevertheless, the average shale volume is identified as the most reliable way to estimate dependable and trustworthy volume of shale in the Green reservoirs. The Green field has relatively low volume of shale which are likely fractured. This is evident in the high volume of sand, permeability and hydrocarbon saturation of the reservoirs as it is an established fact that high shale volume has debilitating effects on the hydrocarbon potential. From the findings of this study, we can conclude that the Green wells have high hydrocarbon prospectivity because of its low shale volume, high resistivity, porosity and permeability. It is recommended that the field is highly productive and can be explored by appropriate authorities.

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