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Research Article

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Petrophysical and Reservoir Summation for the Miocene Niger Delta Region, Nigeria

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Abstract The petrophysical characteristics using interactive Petrophysics (IP) software of two wells within the Niger Delta field has been studied to evaluate their hydrocarbon potential. For each well, the following logs were collected; resistivity log, sonic log, density log, neutron log, photo electric log, self potential and gamma-ray log. These in situ well logs were subjected to well log analysis and interpretation methods. The following Petrophysical parameters: porosity, water saturation, reservoir thickness and volume of shale were estimated for each hydrocarbon-bearing zone delineated for each well. A total of four reservoirs were identified in the well (two each), the findings after the petrophysical evaluation indicate that the wells entered formations with good reservoir quality in terms of porosity, which ranges from (25.2 – 29.7 %), shale volume (8.7% - 23.6 %), bulk volume of water (4.6 % - 8.7%), water saturation (17.1% - 33.9%) hydrocarbon saturation (66.1% - 82.9%) and net pay zone (7.468 – 31.852 m). The hydrocarbon reservoirs in this study were found to be in the Agbada formation, which is in conformity with the geology of the Niger Delta of Nigeria.

Keywords Volume of Shale, Porosity, Water Saturation, Net Pay, Reservoir

1. Introduction

The porosity of a sedimentary layer is an important consideration when attempting to evaluate the potential volume of hydrocarbons, water and gas it may contain. Almost all reservoirs have porosity in a range of 5 to 45 % with the majority falling between 10 to 20% [1-2]. Applied porosity analysis in the geodynamic processes influences the evolution of sedimentary basins including the Niger Delta basin and continental margin of Nigeria and hydrocarbon potentials of the basins.

Porosity can be determined by using different logging devices. If a density logging tool is to be used, the rock matrix density must be known in order to determine the porosity. Likewise, using sonic log for porosity determination, the known parameter must be the matrix travel time and for neutron log, the parameter that must correspond to the rock type is the matrix setting for the neutron logging tool. If the encountered lithologies are simple or if the detailed information about the geology of the formation is shown, many problems should not arise in the determination of these parameters [3]. Reservoir characterization is a process of describing various reservoir properties using all the available data to provide reliable reservoir models for accurate reservoir performance prediction [4]. In order to calculate the hydrocarbon reserve in a formation, the water saturation amount must be known [5].

According to Islam, *et al.*, [6] petrophysical parameter studies are very important for the development and production of the well and estimation of the hydrocarbon reserves in any gas field. The geological model of gas reservoir is based on the estimates of reservoir properties such as lithology, porosity, permeability and fluid type [7]. Petrophysical evaluation has a unique opportunity to observe the relationship between porosity and saturation [8]. According to Islam *et al.*, [9] well log data are used to give erroneous values for water saturation and porosity in the presence of shale effect. The determinations of reservoir quality and formation evaluation processes are largely depending on quantitative evaluation of petrophysical analysis. Islam [10] describes Reservoir characterization as the process of mapping a reservoir's thickness, net to gross ratio, pore fluid, porosity, permeability and water saturation.

The formations in the Niger Delta, Nigeria consist of sands and shales with the former ranging from fluvial (channel) to fluvial-marine (barrier bar), while the later are generally fluvial-marine or lagoon. These Formations are mostly unconsolidated and it is often not feasible to take core samples or make drill stem tests [11]. Formation evaluation is consequently based mostly on logs, with the help of mud logger and geological information as in this study. Petrophysical parameters like the lithology, fluid content, porosity, water saturation, hydrocarbon saturation and permeability were derived from the well log data [12]. The main petrophysical parameters needed to evaluate a reservoir are its porosity, hydrocarbon saturation, thickness, area, and permeability [13-14].

In the evaluation of a clastic reservoir, the presence of clay particles or shale within the sand is a parameter which must be considered. Shaliness is known to affect both formation characteristic and logging tool response.

Carbonates, non-clastic reservoirs, are characteristically limestone and dolomite. Their importance as reservoir rocks should not be underestimated. Approximately, 50% of hydrocarbon reservoirs are carbonate rocks [15-16]. Well-logging tools respond primarily to the chemical nature of matrix and pore fluids. The lithology of a reservoir impacts the petrophysical calculations in numerous ways.

The depositional environment and sediments being deposited will define the grain size, its sorting and distribution within the reservoir interval. In most sandstone reservoirs, the depositional environment controls the porosity/permeability relationship [17-18].

2. Geologic setting of study area

The Niger Delta Basin, is an extensive rift basin situated on the reactive continental margin near the west coast of Nigeria in the Niger Delta and the Gulf of Guinea, with suspected or confirmed access to Cameroon, Equatorial Guinea, and São Tomé and Príncipe [19]. The Niger Delta Basin lies within a wider tectonic structure in the south-westernmost part. It covers an area within longitude 4^0E - 9^0E and latitudes 4^0N - 9^0N. This basin is very intricate and has a high economic value since it contains a prosperous petroleum system. The filling of sediments has a depth between 9-12 km. It is consisting of several different geological formations indicating how this basin might have developed, as well as the area's regional and large-scale tectonics [20]. The Niger Delta Basin is an extensive basin flanked by several other basins in the area all of which were formed by similar structures.

The sedimentary fill of the Niger Delta basin has been subdivided into three (3) broad lithofacies units, which include the marine shales (Akata Formation); marginal marine sandstones, shales and clays (Agbada Formation); and massive continental sandstones (Benin Formation). The Akata Formation is the oldest units and forms the base of the sequence in each depobelt and has stratigraphic thickness which may reach 7000 m in the central part of the delta. Overlying the Akata Formation is the paralic Agbada Formation represented by sands, shales and clays alternations in various proportion and thickness deposited in a number of delta-front, delta-topset and fluvio-deltaic environments. It has a maximum thickness of about 3000m. The Benin Formation is the youngest unit with variable thickness which becomes thinner offshore [21]. This generally regressive clastic sequence of the delta reaches a maximum thickness of about 9-12 km [22].

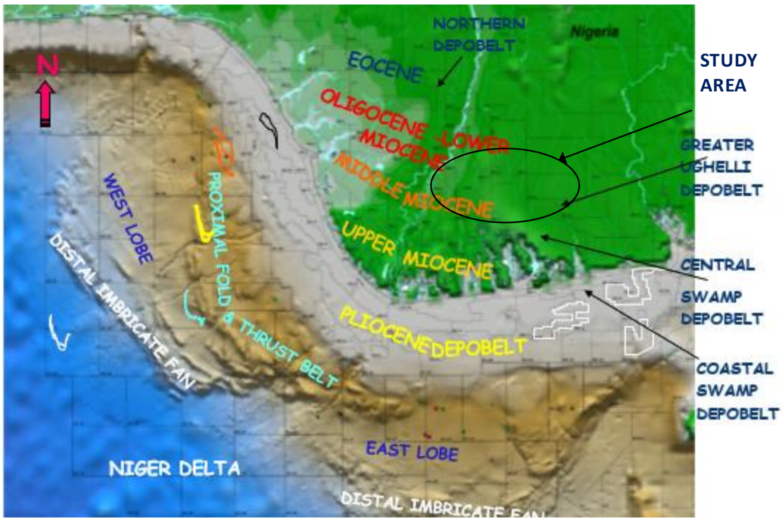

Figure 1: Geology of the Niger Delta Region

3. Methodology

Well logs data were used for this research. These well logs specifically sonic, resistivity, neutron, density and gamma ray log were used to compute porosity, lithology, and volume of shale. Determination of porosity values was achieved by digitizing the sonic logs. The well analysis from Interactive Petrophysics (IP) and data were used for well logging interpretation directly. Accurate estimates of porosity values in certain stratigraphic intervals can be derived from several well log types, i.e. the sonic, neutron or bulk density log. The sonic tool measures the time it takes sound pulses to travel through the formation (Δt_{log}). This time is referred to as the interval transit time, or slowness and it is the reciprocal of velocity of the sound wave. The interval transit time of a given formation is dependent on the lithology elastic properties of the rock matrix, the property of the fluid in the rock and porosity.

The sonic tool is selected to calculate the porosity (ϕ), y in a good borehole condition. The Sonic log is used as porosity method;

$$\phi = \frac{\Delta t_{log} - \Delta t_{max}}{\Delta t_{ft} - \Delta t_{max}} \quad \ldots \quad 1$$

Equation (1) is known as Wyllie Time Average Porosity equation [23].

Δt_{log} is the reading on the sonic log in µs/ft.

Δt_{max} is the transit time of the matrix material (about 55.5 µs/ft.)

Δt_{ft} is the transit time of the saturating fluid (about 189 µs/ft. for fresh water)

Theoretically, the volume fraction of shale can be derived from the gamma ray log as the shale volume is linearly proportional to the gamma ray (GR) log value.

Note that this is valid only under the assumption that radioactive potassium elements of the shale minerals are the sole contributors to the gamma ray log signal:

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad 2$$

GR_{log} is the gamma reading from the log,

GR_{max} maximum gamma reading of the well

GR_{min} minimum gamma reading of the well

The volume of shale can be calculated from the equation below:

$$V_{sh} = 0.08(2^{3.71 I_{GR}} - 1) \quad 3$$

Equation three is Larinor equation for calculating volume of shale [24-25]. When a given zone is water bearing that R_t reverts to the water bearing resistivity (R_o). Therefore, a number of water zones can be plotted as depth versus Rw from calculation [26].

$$F = \frac{R_o}{R_w} \quad 4$$

F = formation resistivity factor or simply formation factor
R_o = resistivity of rock when water saturation is 1 (100% saturated)
R_w = resistivity of saturating water

$$F = \frac{a}{\phi^m} \quad 5$$

Φ = porosity
a = empirical constant (default = 1)
m = cementation exponent (default = 2).
For determination of water saturation of a clean sand formation we use the following equations [27].

$$S_w^n = \frac{R_o}{R_t} \quad 6$$

S_w = water saturation
R_t = resistivity of rock when $S_w < 1$
R_o = resistivity of rock when water saturation is 1 (100% saturated).
Combining the above equations gives Archie's equation, the most fundamental equation in well logging.

$$S_w^n = \frac{aR_w}{R_t\phi^m} = \frac{FR_w}{R_t} \quad 7$$

Practical average Archie's Equation which is the general equation for finding water saturation is

$$S_w = \left[\frac{0.62 \times R_w}{\phi^{2.15} \times R_t}\right]^{\frac{1}{2}} \quad 8$$

4. Results and Discussion

Petrophysical parameters of two wells in the study area were analyzed, two major reservoirs were identified in the two wells. High gamma reading indicates shale formation while low gamma reading indicates sand formations. Also, self potential and photo electric logs were used to infer lithology, where high self potential and photo electric logs indicates sand units, while low values of self potential and photo electric logs are shale units. The wells are comprised of sand-shale units, with sand (sandstone) been the dominant lithology in the study area. Density and Neutron logs were used to discriminate fluid (Gas, Oil and Hydrocarbon) with resistivity log been the main log for fluid discrimination. The sonic log was used to calculate the porosities of the wells, porosities within the field were observed generally to decrease with depth.

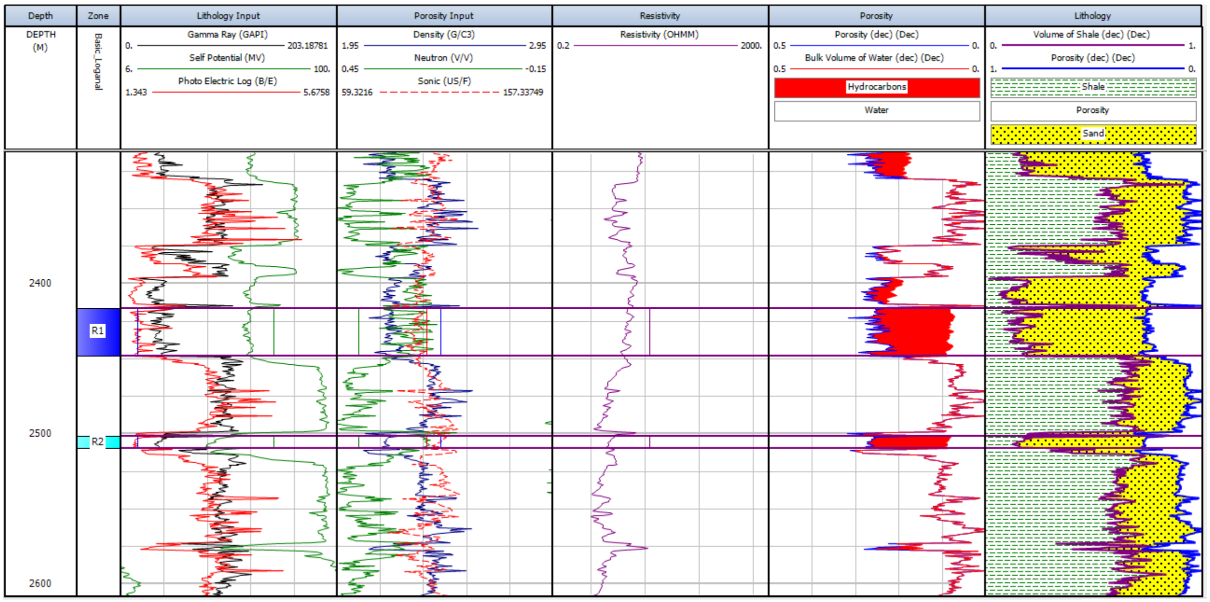

Figure 2: Input and Petrophysical plot of well G14

Figure 2, shows the composite log panel for well G14 with, with depth, zone (reservoirs zones R1 and R2), lithology input (gamma ray, self potential and photo electric log), porosity input (density, sonic and neutron), resistivity input (deep resistivity), saturation (porosity, BVW (bulk volume of water) and molded hydrocarbon and water saturation) and finally lithology pane (Vsh (volume of shale), porosity, molded sand, shale and porosity)

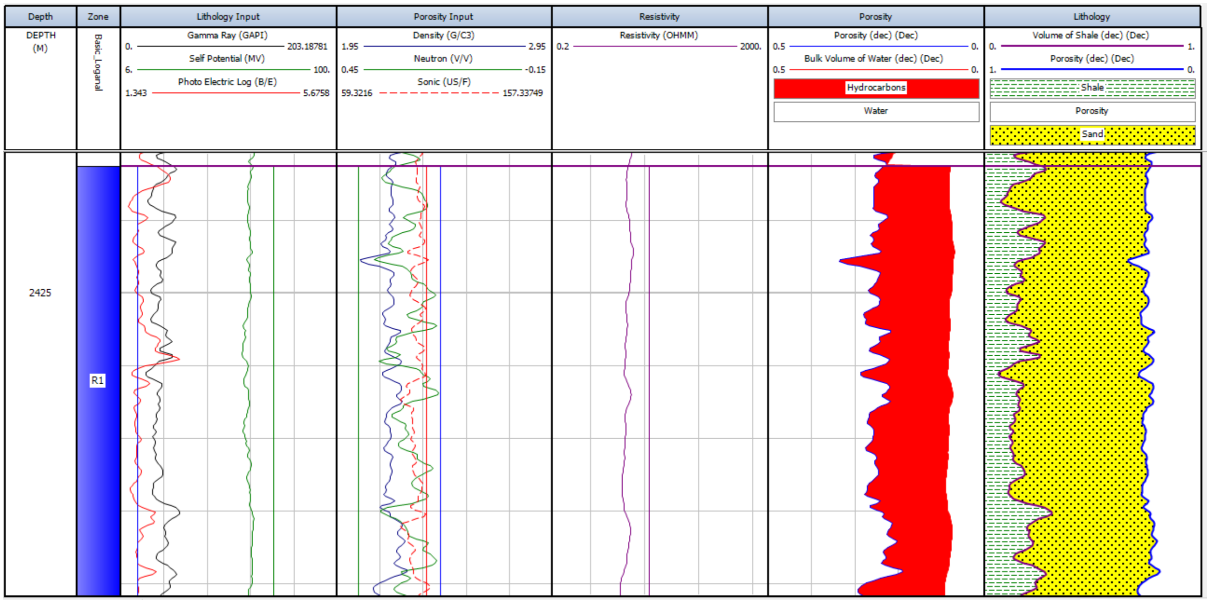

Figure 3: Input and Petrophysical plot of well G14 R1

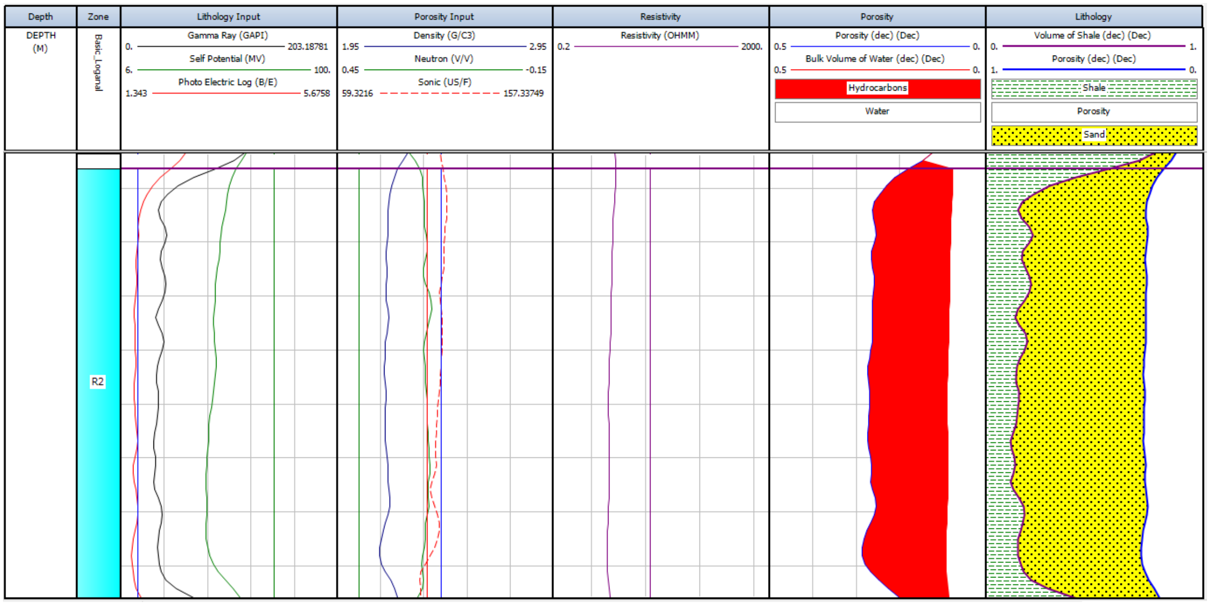

Figure 4: Input and Petrophysical plot of well G14 R2

Figures 3 and 4 are log panels for reservoirs R1 and R2 in well G14, Table 1, shows the minimum, maximum and mean values of the input logs and the estimated petrophysical parameters of the reservoirs.

G14 R1, is between 2416.302 – 2448.001 m, with a net pay of 31.852 m, the mean volume of shale is 0.174 with a gamma ray value of 38.062 gAPI which corresponds to a porosity value of 0.252. The reservoir shows a viable economical reservoir having 67.3 % accumulation of hydrocarbon with a bulk volume of water of 0.082.

G14 R2, is between 2501.646 – 2509.876 m, with a net pay of 8.382 m, the mean volume of shale is 0.195 with a gamma ray value of 40.756 gAPI which corresponds to a porosity value of 0.258 The reservoir show a viable economical reservoir having 66.1 % accumulation of hydrocarbon with a bulk volume of water of 0.087.

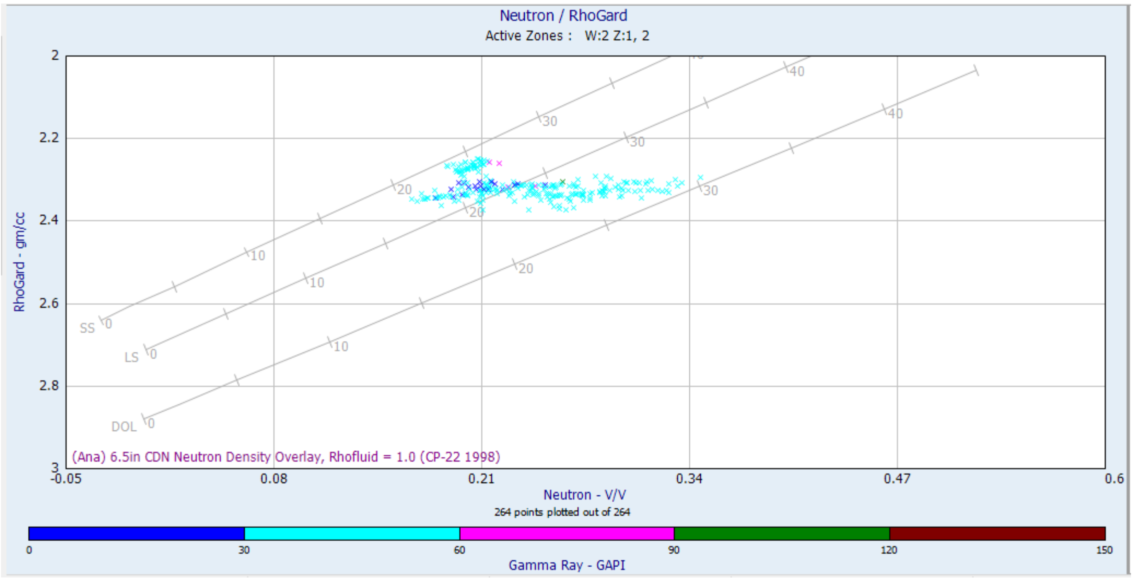

Figure 5: Neutron-Density crossplot with Gamma ray for the reservoirs in well G14

Figure 5 shows the fluid discrimination in the reservoirs in well G14, having low neutron values with high density. The gamma ray values indicate the sand are mostly clean sand.

Table 1: Petrophysical parameters of reservoirs in well G14

Curve	Units	Top: 2416.302m, Bottom: 2448.001m, Net: 31.852m			Top: 2501.646m, Bottom: 2509.876m, Net: 8.382m		
		Min	**Max**	**Mean**	**Min**	**Max**	**Mean**
Gamma Ray	gAPI	23.875	55.547	38.062	30.225	92.404	40.756
Self Potential	mV	58.566	63.750	61.577	42.829	58.039	47.440
Photo Electric Log	B/E	1.500	2.522	1.756	1.557	2.324	1.683
Density	G/C3	2.058	2.276	2.197	2.146	2.239	2.182
Neutron	V/V	0.166	0.347	0.245	0.188	0.260	0.206
Sonic	US/F	88.252	101.699	95.394	96.751	109.172	104.765
Resistivity	OHMM	3.638	6.396	4.741	1.962	2.900	2.296
Porosity	dec	0.190	0.336	0.252	0.169	0.286	0.258
Bulk Volume of Water	dec	0.070	0.093	0.082	0.077	0.093	0.087
Volume of Shale	dec	0.063	0.311	0.174	0.113	0.599	0.195
Water Saturation	Dec	0.218	0.457	0.327	0.306	0.484	0.339

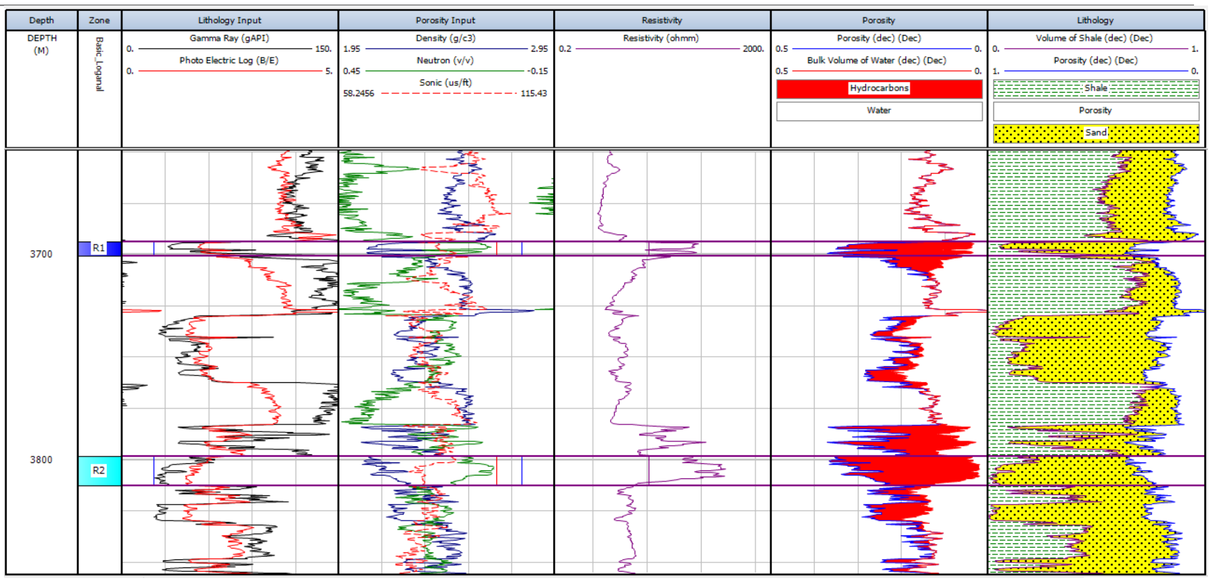

Figure 6: Input and Petrophysical plot of well G52

Figure 6, shows the composite log panel for well G52 with, with depth, zone (reservoirs zones R1 and R2), lithology input (gamma ray, self potential and photo electric log), porosity input (density, sonic and neutron), resistivity input (deep resistivity), saturation (porosity, BVW (bulk volume of water) and molded hydrocarbon and water saturation) and finally lithology pane (Vsh (volume of shale), porosity, molded sand, shale and porosity)

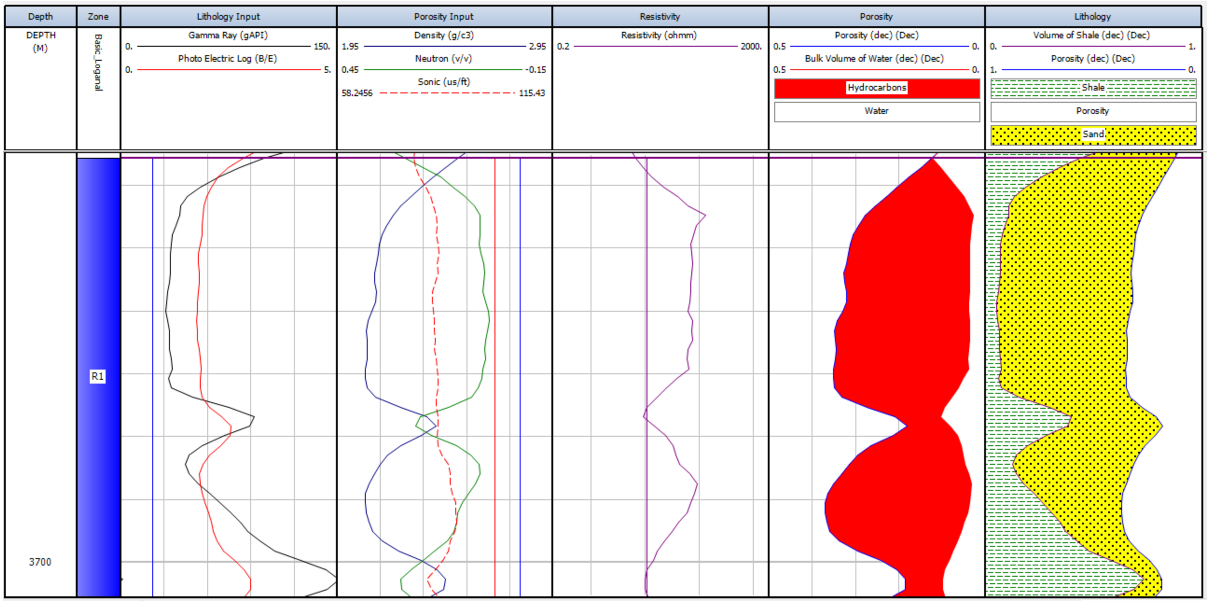

Figure 7: Input and Petrophysical plot of well G52 R1

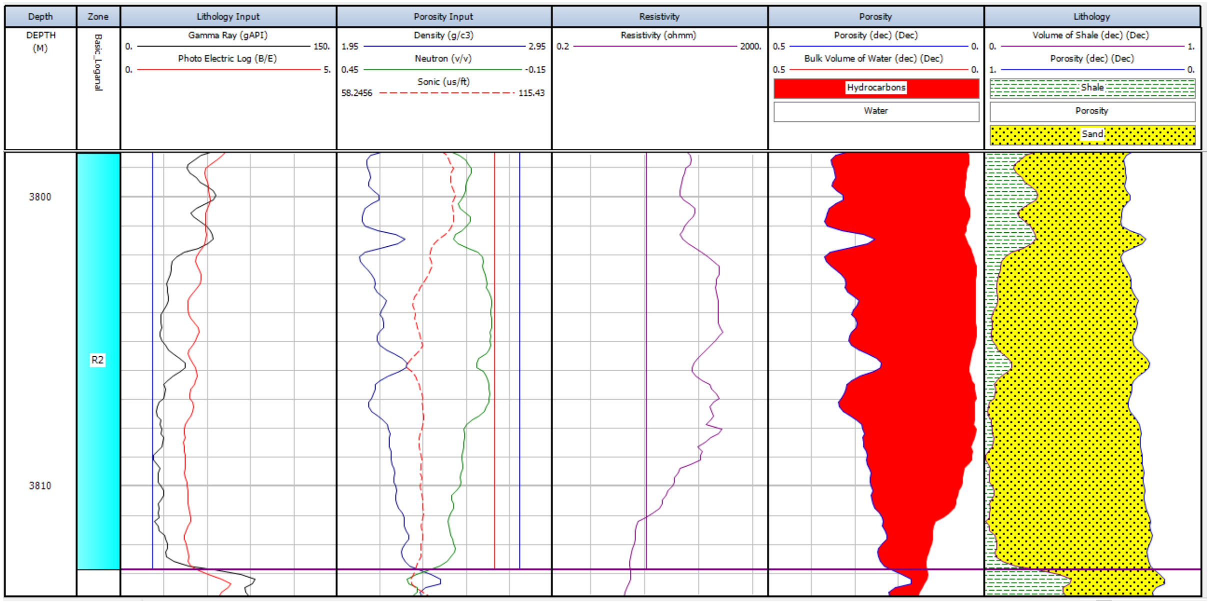

Figure 8: Input and Petrophysical plot of well G52 R2

Figure 7 and 8 are log panels for reservoirs R1 and R2 in well G52, Table 2, shows the minimum, maximum and mean values of the input logs and the estimated petrophysical parameters of the reservoirs.

G52 R1, is between 3693.566 – 3700.882 m, with a net pay of 7.468 m, the mean volume of shale is 0.236 with a gamma ray value of 63.805 gAPI which corresponds to a porosity value of 0.291. The reservoir shows a viable economical reservoir having 76.5 % accumulation of hydrocarbon with a bulk volume of water of 0.058.

G52 R2, is between 3798.265 – 3812.896 m, with a net pay of 14.783 m, the mean volume of shale is 0.087 with a gamma ray value of 37.638 gAPI which corresponds to a porosity value of 0.297 The reservoir shows a viable economical reservoir having 82.9 % accumulation of hydrocarbon with a bulk volume of water of 0.046.

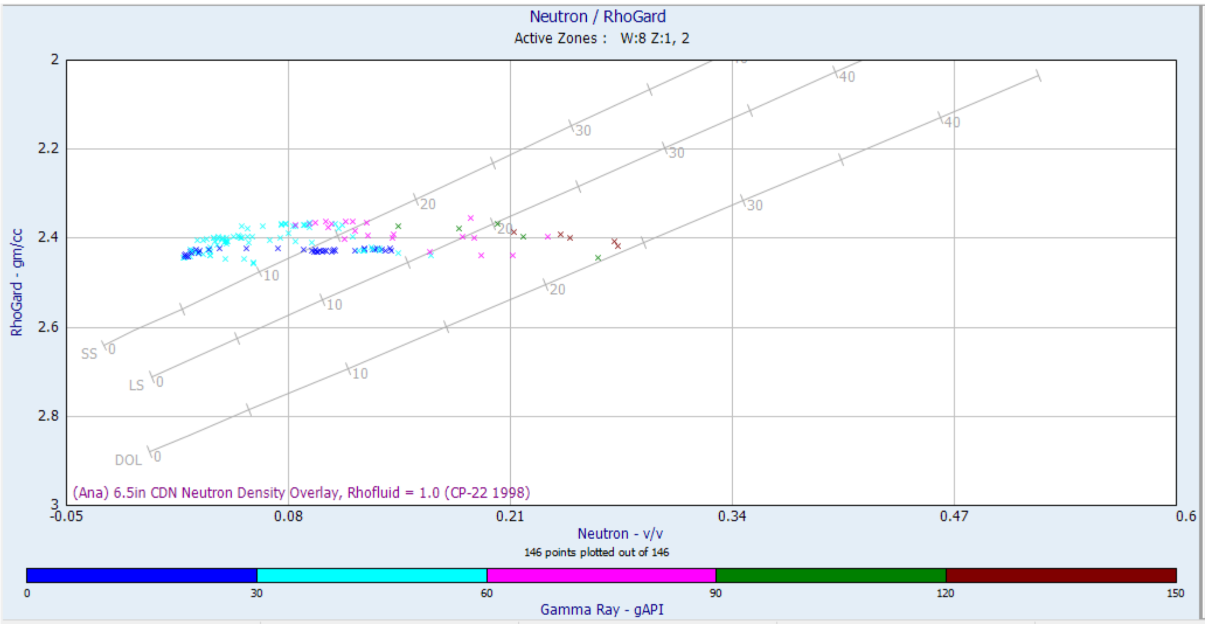

Figure 9: Neutron-Density crossplot with Gamma ray for the reservoirs in well G 52

Figure 9 show the fluid discrimination in the reservoirs in well G52, having low neutron values with high density. The gamma ray values in well G52 R2, indicate the sand are mostly dirty sand due to high radioactive elements in the reservoir, while G52 R2 is mostly clean sand.

Table 2: Petrophysical parameters of reservoirs in well G52

Curve	**Units**	**Top: 3693.566m, Bottom: 3700.882m, Net: 7.468m**			**Top: 3798.265m, Bottom: 3812.896m, Net: 14.783**		
		Min	**Max**	**Mean**	**Min**	**Max**	**Mean**
Gamma Ray	gAPI	31.176	151.276	63.805	22.736	82.187	37.638
Photo Electric log	B/E	1.751	3	2.1	1.452	2.631	1.722
Density	g/c3	2.079	2.51	2.205	2.054	2.331	2.174
Neutron	v/v	0.027	0.273	0.112	0.019	0.193	0.081
Sonic	us/ft	78.646	91.118	85.178	76.746	89.622	82.209
Resistivity	ohmm	6.714	136.091	46.909	5.433	288.332	110.181
Porosity	dec	0.125	0.371	0.291	0.216	0.371	0.297
Bulk Volume of Water	dec	0.027	0.122	0.058	0.019	0.136	0.046
Volume of Shale	dec	0.051	0.731	0.236	0.003	0.34	0.087
Water Saturation	dec	0.093	0.98	0.235	0.056	0.62	0.171

5. Conclusion

Petrophysical analysis was carried out for all the identified hydrocarbon intervals, from two wells studied in the Niger Delta Fields using suites of geophysical well logs. One of the most important tasks in reservoir engineering is characterizing different parameters of the reservoir, which have been done in this work. Water saturation is a parameter which helps evaluating the volume of hydrocarbon in reservoirs.

Our analysis reveals that the lithology of the region is mostly sand with inter bedding of shaly, the shale volume ranges from 8.7 % to 23.6 %. The porosity of the region is highly favorable of a potential hydrocarbon reservoir and it was ranged from 25.2 % to 29.7 %. In all the interpreted well, there are high level of accumulation of reservoirs seen from the net pay zones, all the hydrocarbon reservoirs that were observed are located in Agbada formation, which is a Reservoir rock, the source rocks are mostly Shale and have a cap rock which comprises of sand interbedded shale and could be said to be sand shaly rocks.

Reservoir rocks must be porous and permeable, i.e. there must be space between the fragments or grains of the rock and these pores must be interconnected to provide a continuous path for fluid movement, this was observed in most of the reservoir identified in the study area. Also, porosity in the reservoirs follow a downward trend i.e. they decrease with increasing depth

A rock that contains oil and/or gas will have higher resistivity than the same rock completely saturated with formation water and the greater the connate water saturation, the lower the formation resistivity. The electrical properties of the rock are therefore strongly influenced by the water it contains. The quantity of water in the rock is a function of the porosity, and the extent to which that porosity is filled with water (as opposed to hydrocarbons). This explains why the resistivity of a formation is such an important log measurement. From the resistivity, we can determine the percentage of water in the rock.

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