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Research paper

Evaluation of Reservoir's Petrophysical Parameters, Niger Delta, Nigeria

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Abstract

Petrophysical analysis was performed in two wells in the Niger Delta Region, Nigeria. This study is aimed at making available petrophysical data, basically water saturation calculation using cementation values of 2.0 for the reservoir formations of two wells in the Niger delta basin. A suite of geophysical open hole logs namely Gamma ray; Resistivity, Sonic, Caliper and Density were used to determine petrophysical parameters. The parameters determined are; volume of shale, porosity, water saturation, irreducible water saturation and bulk volume of water. The thickness of the reservoir varies between 127ft and 1620ft. Average porosity values vary between 0.061 and 0.600; generally decreasing with depth. The mean average computed values for the Petrophysical parameters for the reservoirs are: Bulk Volume of Water, 0.070 to 0.175; Apparent Water Resistivity, 0.239 to 7.969; Water Saturation, 0.229 to 0.749; Irreducible Water Saturation, 0.229 to 0.882 and Volume of Shale, 0.045 to 0.355. The findings will also enhance the proper characterization of the reservoir sands.

Keywords: *Bulk Volume of Water; Lithology; Porosity; Reservoir; Volume of Shale.*

1. Introduction

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 (Adesida, A. A., et al 1997). In order to calculate the hydrocarbon reserve in a formation, one needs to know the water saturation amount (Ejedawe, J. E. 1989). Improper calculation of water saturation leads to great errors in reserve estimation. The goal of reservoir characterization is to predict the spatial distribution of such Petrophysical parameter on a field scale. Archie stated that a broad relationship exists between porosity and permeability of a formation. Petrophysics also refer to the careful and purposeful use of rock physics data and theory in the interpretation of reservoir geophysics observation (Pirson S.J., 1963).
The main Petrophysical properties are porosity, permeability, saturation and capillarity. Porosity determines the storage capacity for hydrocarbon sand permeability determines the fluid flow capacity of the rock. Saturation is the fraction of the porosity that is occupied, by hydrocarbons or by water. The most common technique to determine Petrophysical characteristics is well logging. Log-derived parameters such as porosity, permeability, water saturation and hydrocarbon saturation are the key parameters for characterizing a reservoir to estimate the hydrocarbon volume. Hydrocarbon reservoirs are the main properties of exploration and production companies.
In his pioneering work Archie sets out the fundamentals of rock-type classification. Any porous network is related to its host rock fabric; therefore Petrophysical parameter, such as porosity, permeability and saturation, for any given (type of rock) are controlled by pore sizes and their distribution and interconnection (Archie, G. E. 1942). 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. A rock that contains oil and/or gas will have a higher resistivity than the same rock completely saturated with formation water and the greater the connate water saturation, the lower the formation resistivity. This relationship to saturation makes the formation resistivity factor an excellent parameter for the detection of hydrocarbon zones.
The Niger delta forms one of the world‘s major hydrocarbon provinces and it is situated on the Gulf of Guinea on the west coast of central Africa (Southern Nigeria). It covers an area within longitudes 4º E – 9º E and latitudes 4º N - 9º N. It is composed of an overall regressive clastic sequence, which reaches a maximum thickness of about 12 km. The Niger delta consists of three broad Formations: the continental top facies (Benin Formation), the Agbada Formation and the Akata Formation. The Benin Formation is the shallowest of the sequence and consists predominantly of fresh water-bearing continental sands and gravels. The Agbada Formation underlies the Benin Formation and consists primarily of sand and shale and is of fluvial marine origin. It is the main hydrocarbon-bearing window (Adesida, A. A., et al 1997; Weber, K. J. 1972). The Akata Formation is composed of shale, clays and silts at the base of the known delta sequence. They contain a few streaks of sand, possibly of turbidity origin. The thickness of this sequence is not known for certain, but may reach 7000 m in the central part of the delta.
Petroleum in the Niger Delta is produced from sandstone and unconsolidated sands predominantly in the Agbada Formation. The characteristics of the reservoirs in the Agbada Formation are controlled by depositional environment and the depth of burial. Known reservoir rocks are Eocene to Pliocene in age and are often stacked, ranging in thickness from less than 15 meters with about 10 % having greater than 45 meters thickness (Adesida, A. A., et al 1997; Obaje, N. G. 2005). Porosity slowly decreases with depth because of the age of the sediments. Most known traps in Niger

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delta fields are structural although stratigraphic traps are not uncommon. The structural traps developed during sedimentary deformation of the Agbada paralic sequence. Structural complexity increases from the north (earlier formed depobelts) to the south in response to increasing instability of the under-compacted, overpressured shale. A variety of structural trapping elements, including those associated with simple rollover structures clay-filled channels, structures with multiple growth faults, structures with antithetic faults and collapsed crest structures (Adesida, A. A., et al 1997; Alger, R. P. 1980). On the flanks of the delta, stratigraphic traps are likely as important as structural traps. In this region, pockets of sandstone occur between diapiric structures. Towards the delta toe (base of distal slope) this alternating sandstone-shale sequence gradually grades to essentially sandstone. This is aimed at estimating petrophysical properties of the area to enhance effective characterization of the reservoir sands.

2. Methodology

Well log interpretation method was used to determine some Petrophysical parameters in the study area. The procedures performed an integrated interpretation of well log data and characterized the reservoir formation. The following Petrophysical parameters: porosity, lithology, net pay zone, hydrocarbon saturation and water saturation) were estimated for the reservoir characterization. Well logging interpretation provides the output of log analysis in term of reservoir parameter (Asquith, G. and Gibson. C. 1982; Chapman, R. E. 1983). Quick look log interpretation is generally used in formation evaluation using well logs. This interpretation method provides the information which help geologists, geophysicists, reservoir engineers and drilling engineers in short time. Basically, it relies on overlays of logs, interpretation charts, or graphic methods such as cross plots to minimize methods requiring detailed calculation (Merkel, R. H., 1979; Schlumberger 1989).

The interpretation can derive porosity, water saturation from available well logging data. The zones of reservoir can be identified by many parameters. The permeability is determined from permeability – porosity relationship from core analysis of the corresponding well (Robinson, E. S., 1988).

Zone of reservoir is determined by gamma ray and resistivity logs. Resistivity log is fundamental in formation evaluation because hydrocarbons do not conduct electricity. Therefore, the well logs are split into interval of porous and non-porous rock, permeable and non-permeable rock or shaly and clean sand rock (Welex, 1978; Whiteman, I. K. 1982). The clean sands and sandstones are determined by GR log because GR log records the abundance of the radioactive isotopes of thorium, uranium and potassium. They are usually concentrated in shale and less concentrated in sandstones, so high GR reading can be observed normally and can be used as regional marker because shale is deposited in wide area. Resistivity curve can indicate hydrocarbon in porous and permeable rock.

The sonic tool is selected to calculate the porosity in a good borehole condition. The equation to calculate the porosity based on the sonic log is as follows:

$$\varphi = \frac{\Delta t_{\log} - \Delta t_{\max}}{\Delta t_{ft} - \Delta t_{\max}} \tag{1}$$

For determination of water saturation of a clean sand formation, equation (2) is used, which is given as:

$$S_w^{\ n} = \frac{aR_w}{R_t \varphi^m} = \frac{FR_w}{R_t} \tag{2}$$

Also, the practical average Archie's general equation for finding water saturation is

$$S_w^{\ n} = \left[\frac{0.62 \times R_w}{\varphi^{2.15} \times R_t}\right]^{1/2} \tag{3}$$

The Bulk Volume of water is given by

$$BVW = \varphi \times S_w \tag{4}$$

From water saturation S_w, Hydrocarbon saturation can be estimated using

$$S_W + S_H = 1 \tag{5}$$

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 log value (GR) (Alger, R. P. 1980). 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:

$$I_{GR} = \frac{GR_{\log} - GR_{\min}}{GR_{\max} - GR_{\min}} \tag{6}$$

$$V_{sh} = 0.08\left(2^{3.7 I_{GR}} - 1\right) \tag{7}$$

Equation (7) is Larinor equation for calculating volume of shale.

3. Result and discussion

Well log data from two wells located in Niger Delta area of Nigeria was used for this study. Porosity and lithology of each zone was determined using sonic, gamma ray and resistivity log, thereby dividing the zones into sand and shale zones. The well-known Archie equation (2) was used to calculate the water saturation of the two wells. The important parameters of Archie equation are the cementation factor, m, saturation exponent, n, and tortuosity factor, a. For water saturation estimation, it is a convention to assume that both the cementation factor and saturation exponent are equal to a value of 2 and the tortuosity factor was determined due to its variation in different formations. The water saturation was calculated using the values of the calculated parameters and the well log values.

Table 1 shows the petrophysical analysis of the reservoirs in well 1, while table 2 shows the petrophysical analysis of the reservoirs in well 2. In each of the wells, the hydrocarbon bearing zones where identified based on the net pay zone, lithology and trapping system (type of formation before and after the reservoir). In well 1 two reservoirs were identified and in well 2, three reservoirs were identified. The porosity values within the wells are observed generally to decrease with depth. The estimated average porosity for the two wells ranged between 0.024 and 0.600 decreasing with depth. The low porosity values may be attributed to mainly grain size and sorting effects within the reservoir sands (Chapman, R. E. 1983). The porosity values are however considered to be fairly good for hydrocarbon accumulation. The general trend was observed in the other wells with decreasing porosity with depth.

Table 1: Petrophysical Parameters for Well 1

		Well 1 Net Pay Zone: 7527.5ft Top: 4013ft Bottom: 11540ft			Well 1, Reservoir 1 Net Pay Zone: 1620.5ft Top: 6655ft Bottom: 8275ft			Well 1, Reservoir 2 Net Pay Zone: 127.0ft Top: 8275ft Bottom: 8401.5ft		
Curve	Units	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean
BVW	Dec	0.011	0.533	0.146	0.035	0.438	0.172	0.016	0.485	0.100
CAL	inch	0.000	24.299	10.123	10.209	20.148	11.685	10.428	10.919	10.508
GR	API	0.000	134.423	61.355	27.218	126.834	62.869	31.585	98.770	55.435
LL9D	ohmm	0.000	288.403	0.000	0.982	25.823	4.514	0.964	275.423	27.849
NPHI	Dec	0.000	52.006	0.000	0.000	50.264	10.750	5.201	39.334	18.447
PHI	Dec	0.024	0.600	0.249	0.061	0.600	0.229	0.295	0.585	0.483
RHOB	gm/cc	0.000	2.589	0.900	1.594	2.495	2.217	1.969	2.368	2.132
RWapp	ohmm	0.009	87.287	1.127	0.013	3.645	0.239	0.164	87.287	7.969
SONIC	μs/ft	0.000	170.338	103.848	63.477	127.680	103.719	96.613	115.180	105.349
SW	Dec	0.027	1.000	0.559	0.094	1.000	0.749	0.029	1.000	0.229
SWu	Dec	0.027	1.300	0.650	0.094	1.300	0.871	0.029	1.011	0.229
VSH	Dec	0.051	1.000	0.339	0.074	0.823	0.355	0.082	0.604	0.268

Table 2: Petrophysical Parameters for Well 2

		Well 2 Net Pay Zone: 6647.0ft Top: 6744ft Bottom: 14921ft			Well 2, Reservoir 1 Net Pay Zone: 523.0ft Top: 6744ft Bottom: 7266.5ft			Well 2, Reservoir 2 Net Pay Zone: 1644.5ft Top: 10583.5ft Bottom: 12336.5ft			Well 2, Reservoir 3 Net Pay Zone: 199.0ft Top: 12138ft Bottom: 12336.5ft		
Curve	Units	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean
BVW	Dec	0.009	0.525	0.225	0.011	0.525	0.114	0.009	0.339	0.175	0.033	0.198	0.070
CAL	Inch	0.000	23.672	------	12.469	23.641	14.746	8.123	22.656	12.977	8.123	9.588	8.213
GR	API	0.000	174.500	57.203	28.250	97.326	48.302	24.228	111.402	70.055	24.228	91.565	49.712
LL9D	ohmm	0.000	1323.995	------	0.067	747.908	9.456	0.487	1323.995	25.426	4.474	93.106	29.717
NPHI	Dec	0.000	0.533	------	0.137	0.450	0.282	0.000	0.476	0.000	0.109	0.422	0.173
PHI	Dec	0.119	0.536	0.262	0.176	0.536	0.306	0.119	0.384	0.246	0.119	0.300	0.215
RHOB	gm/cc	0.000	2.666	------	1.727	2.398	2.165	0.000	2.588	------	2.141	2.588	2.304
RWapp	ohmm	0.008	85.276	0.705	0.008	85.276	0.936	0.051	76.097	1.995	0.112	5.630	1.497
SONIC	μs/ft	0.000	187.625	------	7.875	187.625	112.275	0.000	111.188	------	0.000	------	------
SW	Dec	0.034	1.000	0.868	0.034	1.000	0.373	0.037	1.000	0.729	0.135	0.954	0.343
SWu	Dec	0.034	1.300	1.062	0.034	1.300	0.375	0.037	1.300	0.882	0.135	0.954	0.343
VSH	Dec	0.000	1.000	0.235	0.000	0.529	0.056	0.000	0.721	0.230	0.000	0.452	0.045

3.1. Well 1

Figure 1 is the log interpretation for well 1; figure 3 is the log interpretation for well 1, reservoir 1 while figure 4 is the log interpretation for well 1, reservoir 2. Reservoir 1, the sand formation shows a higher hydrocarbon saturation compared to the shale formations. The mean estimated hydrocarbon saturation of reservoir 1 is 0.251, with a minimum value of 0.906. The mean porosity of the reservoir is 0.229 which is very good for hydrocarbon saturation. The mean computed values for Petrophysical parameters are; bulk volume of water 0.172, apparent water resistivity 0.239, water saturation 0.749, irreducible water saturation 0.871 and volume of shale 0.355. Reservoir 2 indicated a very high presence of hydrocarbon saturation, having a mean estimated hydrocarbon of 0.771 and porosity of 0.483. The mean computed values for Petrophysical parameters are; bulk volume of water 0.100, apparent water resistivity 7.969, water saturation 0.229, irreducible water saturation 0.229 and volume of shale 0.268. Both reservoirs have a good trapping system and good net pay zone.

3.2. Well 2

Figure 2 is the log interpretation for well 2; figure 5 is the log interpretation for well 2, reservoir 1; figure 6 is the log interpretation for well 2, reservoir 2, while figure 7 is the log interpretation for well 2, reservoir 3. Reservoir 1 indicated a very high presence of hydrocarbon saturation. The mean estimated hydrocarbon saturation of reservoir 1 is 0.627, while the porosity is 0.694. The mean computed values for Petrophysical parameters are; bulk volume of water 0.114, apparent water resistivity 0.936, water saturation 0.373, irreducible water saturation 0.375 and volume of shale 0.056. Reservoir 2 has a mean estimated hydrocarbon of 0.271 and porosity of 0.246. The mean computed values for Petrophysical parameters are; bulk volume of water 0.175, apparent water resistivity 1.995, water saturation 0.729, irreducible water saturation 0.882 and volume of shale 0.230. Reservoir 3 has a mean estimated hydrocarbon of 0.657 and porosity of 0.215. The mean computed values for Petrophysical parameters are; bulk volume of water 0.070, apparent water resistivity 1.497, water saturation 0.343, irreducible water saturation 0.343 and volume of shale 0.045. All reservoirs have a good trapping system and a good net pay zone.

The total porosity in the hydrocarbon bearing zone was found to range from 0.061 to 0.600. The bulk of the hydrocarbon encountered in the Niger Delta basin was found to be within a depth range of 6,655 – 12,336.5ft (2028.4 – 3760.2m) as compared to the values gotten by (Falebita, B. 2003) (about 1,200 – 3,650m), (Okechukwu, E. A, et al 2013) (about 624.8 – 3,541.8m) and (Aigbedion, I., 2007) (about 2,510 – 3,887m). The hydrocarbon reservoirs were found to be in the Agbada formation, which is in conformity with the geology of the Niger Delta, Nigeria.

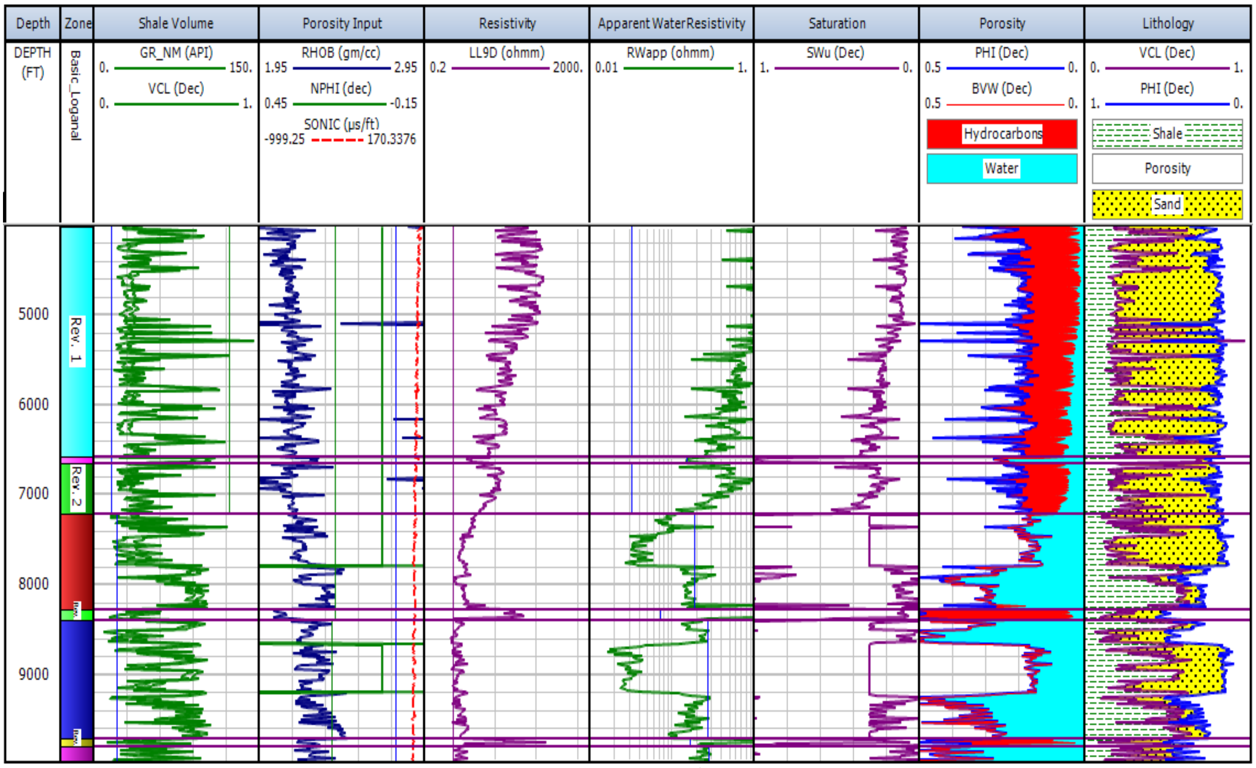

Fig. 1: Log Interpretation for Well 1.

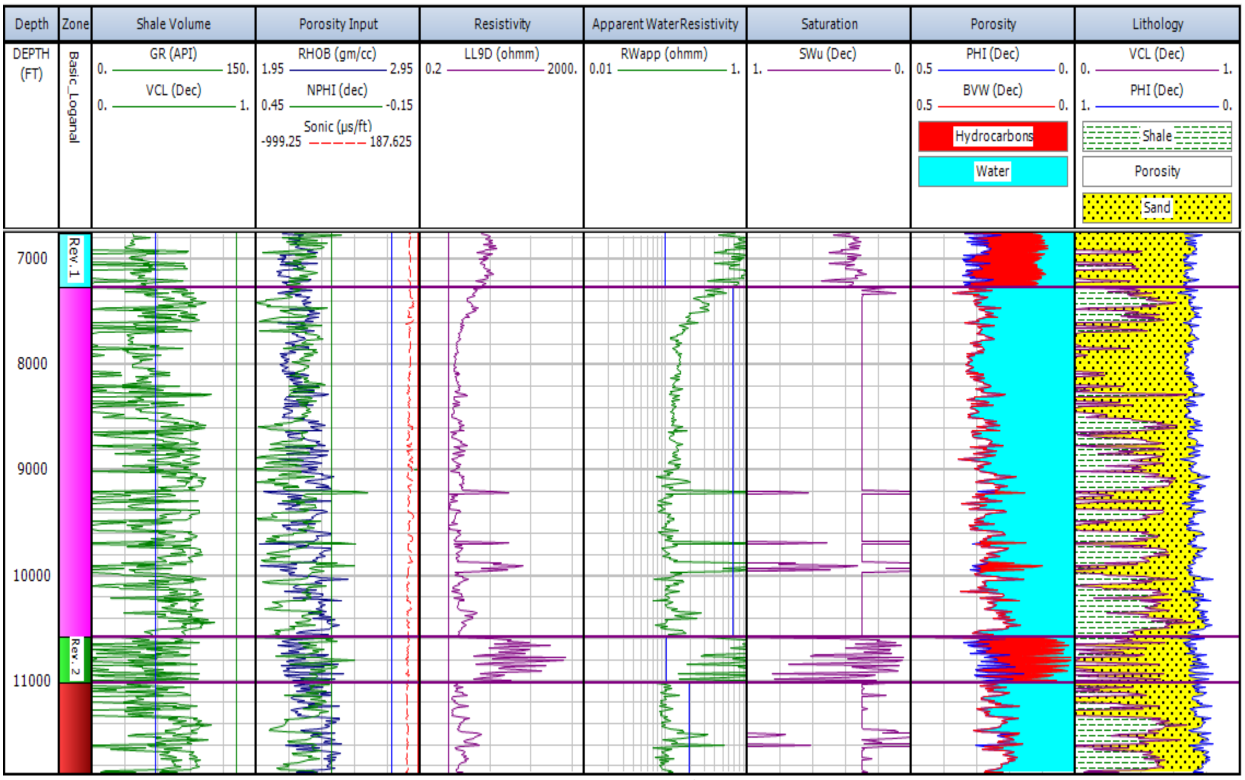

Fig. 2: Log Interpretation for Well 2.

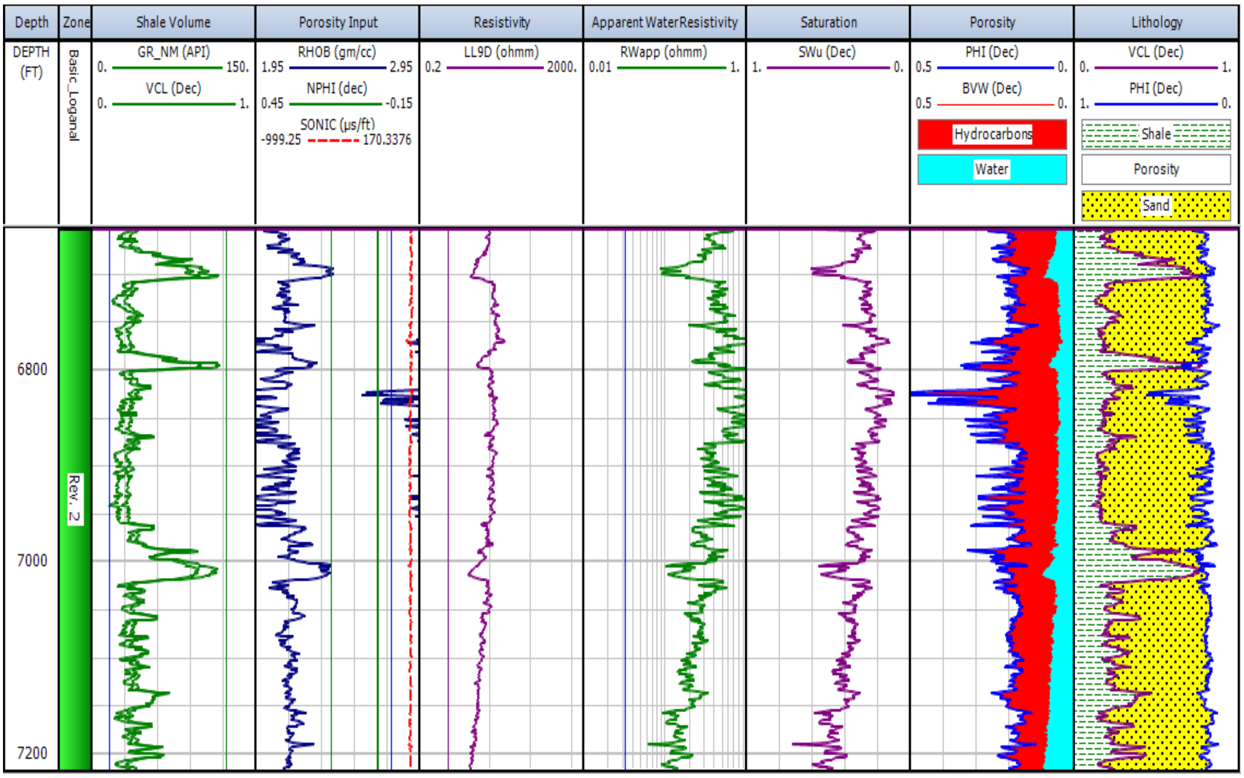

Fig. 3: Log Interpretation for Well 1, Reservoir 1.

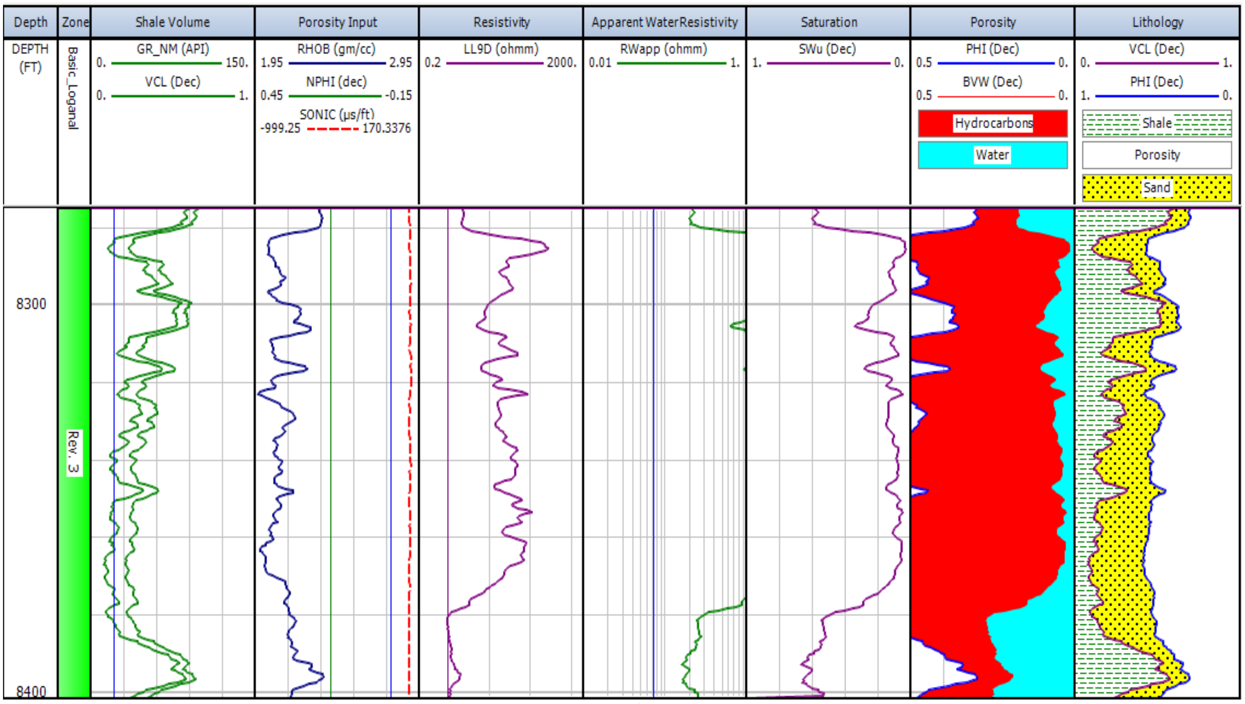

Fig. 4: Log Interpretation for Well 1, Reservoir 2.

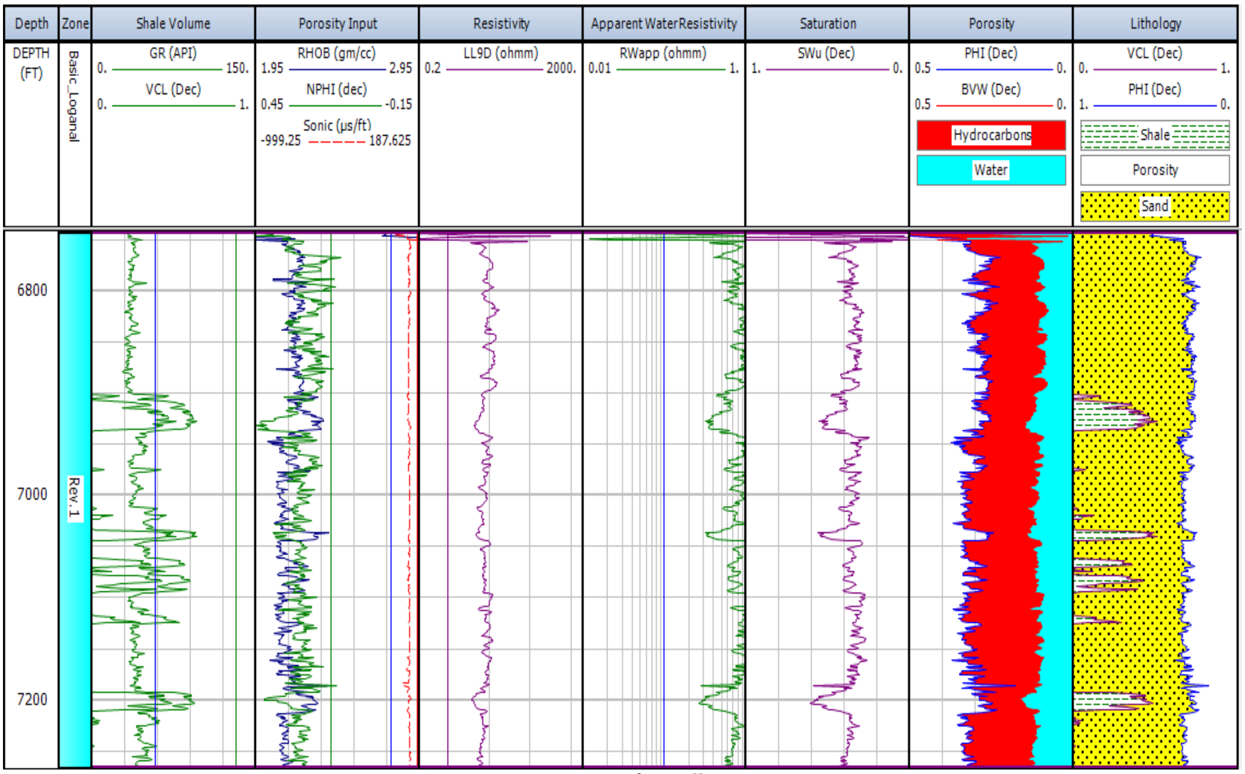

Fig. 5: Log Interpretation for Well 2, Reservoir 1.

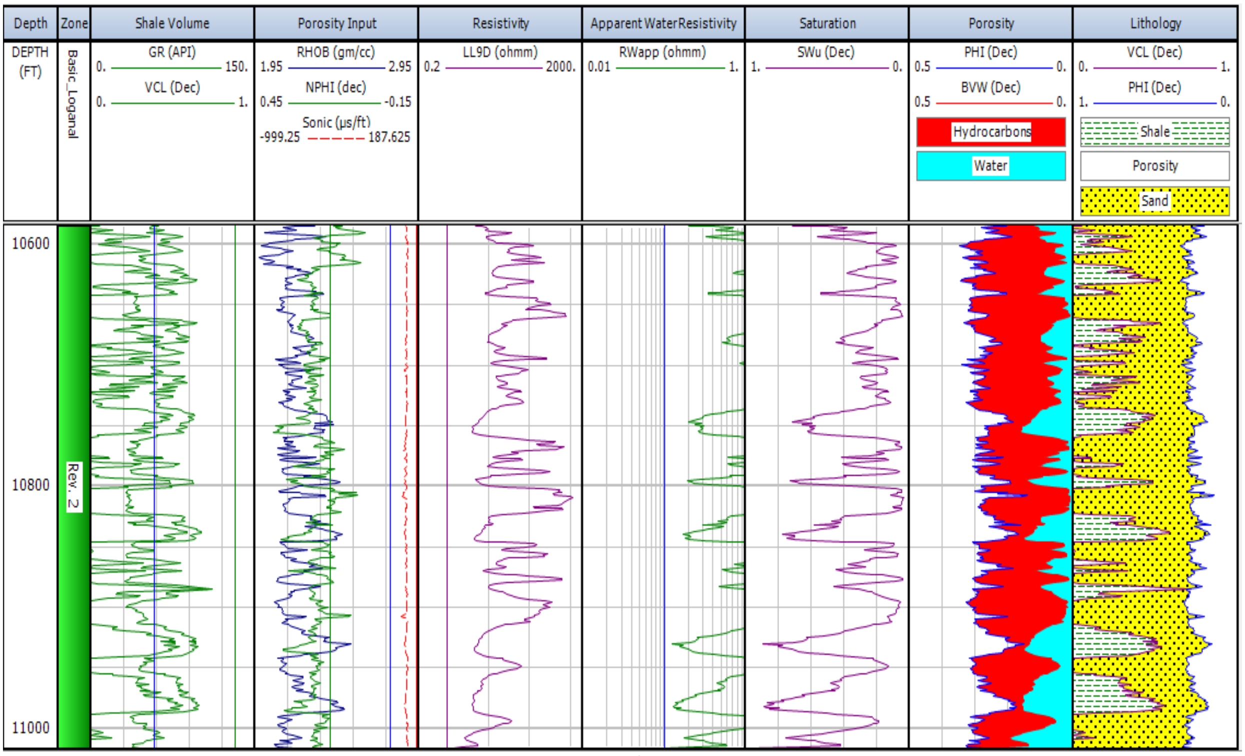

Fig. 6: Log Interpretation for Well 2, Reservoir 2.

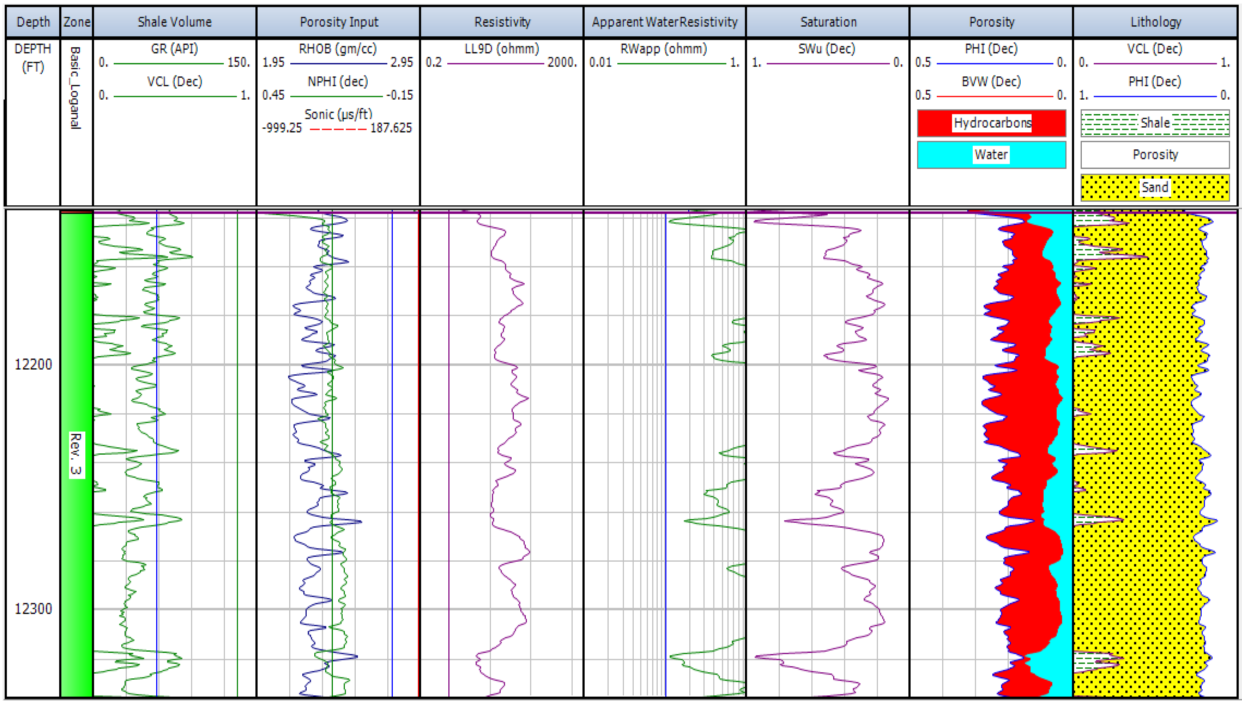

Fig. 7: Log Interpretation for Well 2, Reservoir 3.

4. Conclusion

Well log data from the deep parts of the two wells located in the Niger delta basin were used in the determination of some petrophysical characteristics of the reservoir formations. Well log data were obtained from Sonic, Calliper, Neutron, Density Gamma-ray and Resistivity logs. The petrophysical characteristics investigated were lithology, porosity, hydrocarbon saturation and water saturation. The results of the analysis revealed the presence of both sand and shale units. The results of this study will also enhance the proper characterization of the reservoir sands. The thickness of the reservoir is highly variable, ranging between 127ft and 1620ft. Average porosity values vary between 0.061 and 0.600 and generally decreasing with depth. The mean average computed values for the Petrophysical parameters for the reservoirs are; bulk volume of water 0.070 to 0.175, apparent water resistivity 0.239 to 7.969, water saturation 0.229 to 0.749, irreducible water saturation 0.229 to 0.882 and volume of shale 0.045 to 0.355.

5. Nomenclatures

Porosity (PHI).
Water Saturation Unlimited (S_{wU}).
Water Saturation (S_W).
Bulk Volume Water (BVW).
Shale Volume (VSH).
Apparent Water Resistivity (R_{wapp}).
Caliper Log (CAL).
Gamma Log (GR).
Resistivity Log (LL9D).
Neutron Log (NPHI).
Density Log (RHOB).
Sonic Log (SONIC).

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