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Petrophysical Analysis and Reservoirs Characterization of the Late Miocene Strata in Wb-Field, Niger Delta Basin, Nigeria

Ikechukwu O. Azudi[1], Okechukwu N. Ikegwuonu[1], Osita I. Chiaghanam[1], and Chibuike H. Uwajingba[2]

[1] *Department of Geology, Chukwuemeka Odumegwu Ojukwu University, Uli, Anambra State, Nigeria*

[2] *Department of Land Survey and Geoinformatics, Federal Polytechnic Ugep, Cross River State, Nigeria*

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Abstract

Petrophysical analysis of Upper Miocene reservoir interval of producing WB-field in the Niger Delta Basin was carried out to establish the relationship between core plug permeability and porosity and the log measurements using Regression analysis, and to generate Cross-plots of different log measurements (neutron porosity (NPHI), gamma-ray (GR), bulk density (RHOB) and effective porosity (PHIE)) vs. core-plug porosity and permeability measurements, using Prism to assess which log measurements best predicted core observations R-square (R2) as defined by correlation coefficients of regression equation fit to each cross plot, and also to determine which of the log properties relate best to the actual core measurements using cross-plotting of Log-derived effective porosity (PHIE), gamma-ray and bulk density logs against the core data. The materials utilized in this study involve, Core data, (including core descriptions, core photographs and core-plug porosity and permeability measurements), well log suites (including gamma-ray, resistivity, effective porosity, neutron porosity and bulk density) from 30 wells and core data from two wells (WB-37 and WB-49). Results from the Regression analysis show that the cross-plot of core porosity and core permeability for the D-07 interval reveals an excellent correlation between these two parameters with a goodness of fit, R2 value of 0.91. Result from bulk density measurements were found to correlate best with the core measurements, with a R2 value of over 0.86. The derived porosity and permeability values correlate well with the actual core data. Core-to-log shift applied in the WB-37 well and WB-49 well reveals that the thickness of fit (R2) between the core-derived porosity and permeability, and core measurements was greater than 0.8 in both cases. The integration of core and log data enables the development of an algorithm to relate core porosity and permeability to log measurements. Various logs were investigated, but the bulk density log demonstrated the best predictor of porosity and permeability.

Keywords: *Porosity; Permeability; Core data; Petrophysical; Niger Delta Basin.*

1. Introduction

Petroleum accumulation in the Niger Delta Basin is found within the argillaceous sandstones predominantly in the Agbada Formation. It is necessary to delineate the hydrocarbon reservoirs and evaluate them because they represent zones of interest for hydrocarbon exploitation. Based on reservoir geometry and quality, the lateral variation in reservoir thickness is strongly controlled by growth faults; with the reservoirs thickening towards the fault within the down-thrown block [1]. Understanding of reservoir characteristics most importantly porosity, permeability, water saturation, thickness and area extent of the reservoir are crucial factors in quantifying producible hydrocarbon. These parameters are important because they serve as veritable inputs for reservoir volumetric analysis i.e. the volume of hydrocarbon in place. Although there is petroleum accumulation throughout the Agbada Formation, there are several directional trends that form an "oil-rich belt" where the largest oil accumulations are found [2-4]. This belt extends offshore from northwest to southeast and roughly corresponds to the transition between continental and oceanic crust. The oil- rich Agbada belt is also located within the axis of maximum sedimentary thickness. This hydrocarbon distribution was originally attributed to timing of trap Formation relative to petroleum accumulation. The source rock for the petroleum accumulations in the Niger Delta Basin has been a controversial subject. Extensive studies of the Niger Delta Basin have been carried out in association with petroleum exploration and exploitation, but most remain proprietary. Previous studies focused largely on local stratigraphic and structural relationships within individual oilfields and concessions. Some workers have taken their time to describe the petroleum geology and recent depositional environments of the Niger Delta [1,3-7].

However, in terms of petrophysical characterization of reservoirs in the Niger Delta Basin, considerable number of works has been carried out in the WB-Field. Some notable works including [8] who noted evidence for syn-depositional displacement on growth faults across the field. They combined well-log interpretations and laboratory analyses of sidewall cores to aid in the determination of the spatial variation of porosity and permeability within reservoir intervals. Ebuka *et al.* [9] estimated the reservoir potentials of two Wells in Niger Delta Basin using Interactive Petrophysics software. Their results revealed the presence of different sand and shale units, and remarked that the bulk of the hydrocarbon encountered in the Niger Delta Basin was found to be within a depth range of 5,473 – 13,381 ft (1,668.17 – 4,078.53 m), within the Agbada Formation. Anyiam *et al*. [10] assessed the heterogeneity and petrophysical evaluation of reservoirs in the "Akbar Field", Niger Delta Basin, Nigeria. They noted that reservoir qualities of the reservoirs are rarely affected negatively despite the occurrence of the three clay types. They remarked that "inasmuch as the horizontal fluid flow may not have been affected due to good porosity, the vertical flow could be impaired as a result of the presence of numerous laminated clay/shale baffles compartmentalizing the reservoirs''. In addition, they concluded that well logs could be used as an alternative to core data in determining the clay distribution trend sands and the degree of their negative effects of their reservoir qualities. Eje and Ideozu [11] studied the effects of shale volume distribution on elastic properties of reservoirs in Nan tin Field Offshore Niger Delta. Fozao [12] evaluated the hydrocarbon reservoirs rocks containing shale streaks in the eastern Niger Delta Basin using geophysical well logs. Ugbor *et al.* [13] studies the evaluation of the influence of shale on the petrophysical properties of hydrocarbon-bearing reservoir sand in "CAC" Field in the Niger Delta Basin, Nigeria. The results from the petrophysical evaluation show V clay ranges of 13% - 21% and good to very good porosity values that vary from 15% - 25%, while the permeability range from 240.49 - 2406.49 mD except for the sands in RES 7, CAC-3 well where the permeability was low (91 mD). They concluded that the existence of these 3 clay types did not significantly influence the quality of the sands containing the hydrocarbon in the area, except in RES 7, CAC-3. Amupitan, *et al.* [14] carried out petrophysical evaluation of Gabo Field, in the Niger Delta Basin, using gamma-ray, resistivity, neutron, and density logs. They noted that the petrophysical analysis based on available well logs indicates that the hydrocarbon-bearing sands have good petrophysical properties, and that the sands have relatively fair to good reservoir quality and are continuous across most wells in the "Gabo" field. They further remarked that the average shale volume is 0.09 – 0.18, and some of these reservoir sands are very clean with clay content as low as 0.08.

This work aims at presenting a detailed petrophysical analysis and characterization of Late Miocene reservoir interval of producing WB-field of the Niger Delta Basin, using well log suites (including gamma-ray, resistivity, effective porosity, neutron porosity and bulk density) and core data from two wells, to establish the relationship between core plug permeability and porosity and the log measurements. The WB-field is located within Latitudes 5° 43′ 40″ N – 5° 46′ 30″ N and Longitudes 4° 54′ 30″ E – 4° 56′ 30″ E (Fig. 1).

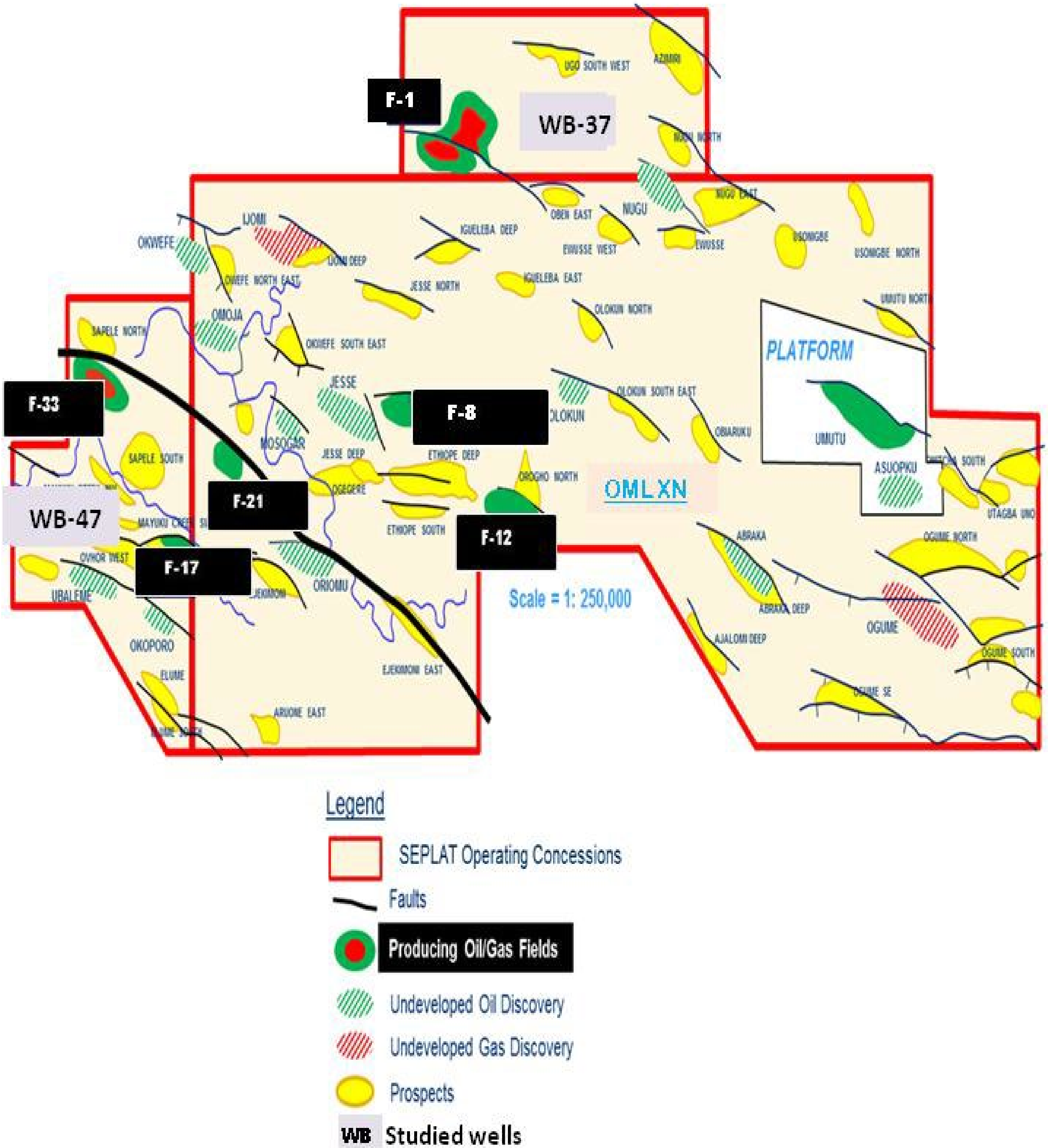

Fig. 1. Field location map of the study area showing locations of the wells.

2. Geologic setting and stratigraphy

The Niger Delta sedimentary basin is located in southern Nigeria, with an area coverage of 300,000 km2, including the geological extent of the Neogene Niger Delta (Akata-Agbada) Petroleum System [15]. The basin is bounded by the Benin Flank in the northwest, and in the northeast by the Anambra Basin and the Abakaliki fold belt, in the east-south-east by the Calabar Flank, while the Cameroon volcanic line lies in the east. The Dahomeyan embayment which is the eastern- most West African transform-fault passive boundary forms the western axis of the basin (Fig. 2).

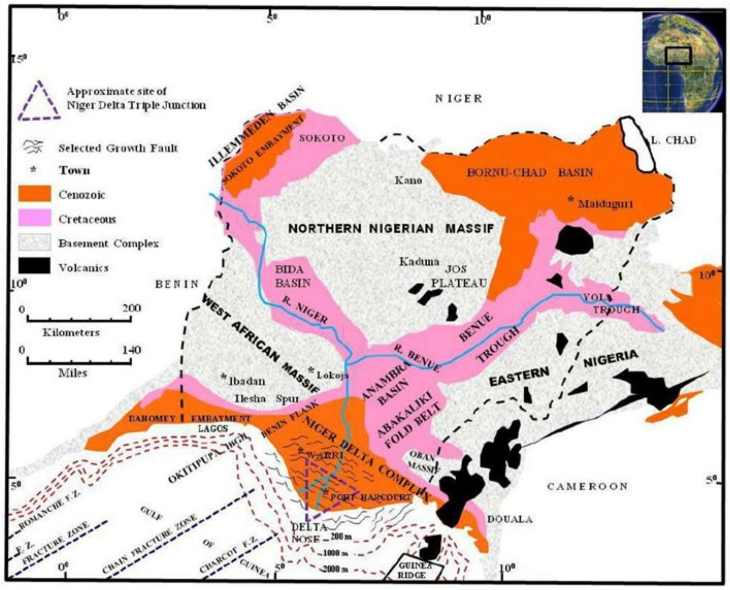

Fig. 2. Map of Niger Delta showing province outline and key structural features (modified after [16, 5]).

The Niger Delta complex is cut by numerous approximately East-West trending syn-sedimentary faults and folds (Fig. 2). These structures are related to growth faults and were initiated by differential loading of the underlying under compacted Akata Shale. The growth faults flatten with depth into a master detachment plane near the top of the over pressured Akata Shale sequence. Most of the faults are listric normal faults, although other types include; crestal faults, flank faults, counter-regional faults and antitheti faults [5].

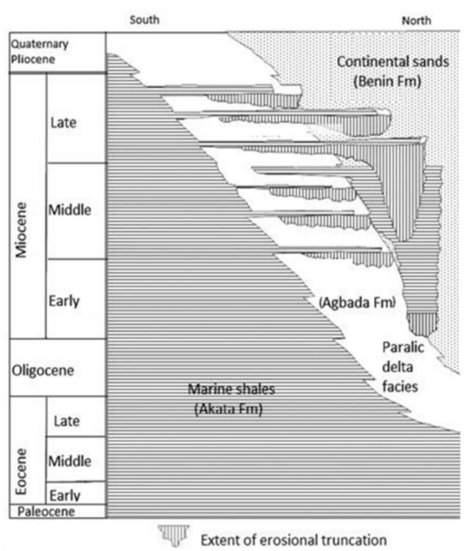

Fig. 3. Stratigraphic column showing the three formations of the subsurface Niger Delta Basin (after [4]).

The stratigraphic sequence of the Niger Delta Basin is divided into three formations namely: Akata, Agbada and Benin from base to the top [4,6] (Fig. 3). The Akata Formation is a holomarine sequence characterized by uniform shale deposit, which forms the basal unit in the basin. The shales are largely under-compacted despite its stratigraphic position which results in the over-pressure of the formation [17-18]. Overlying the Akata Formation is the paralic Agbada Formation, which consists of fine to medium-grained sand/sandstones and mudstones. The lithologic units are locally calcareous, shaly, and contain pyrite [19]. On top of the sequence is the continental Benin Formation, which consists of medium to coarse grained sands/sandstones [20]. The sands are generally fairly to moderately clean, with evidence of organic wood fragments have been found in the formation [4].

3. Materials and methods

3.1. Core analysis

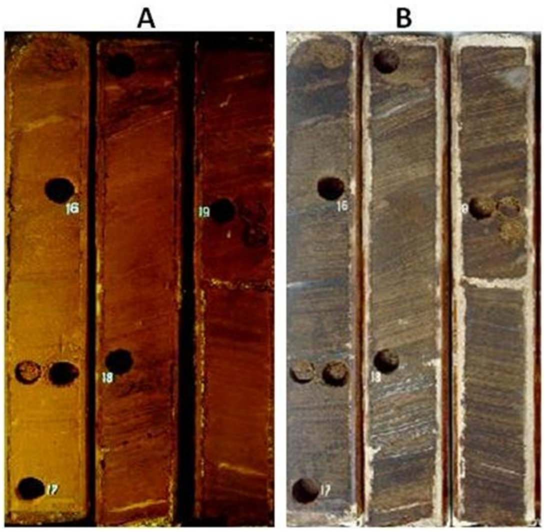

Fig. 4. Core photos of cross–bedded sandstone (upper shoreface facies).

Core data from two wells were used in this study (Fig. 4). These data include core descriptions, core photographs and core-plug porosity and permeability measurements. Core photographs were taken under both white light and ultraviolet light, with the ultraviolet images providing indications of oil staining.

3.2. Petrophysical analysis

Regression analysis was performed to establish the relationship between core plug permeability and porosity and the log measurements. Cross-plots of different log measurements (neutron porosity (NPHI), gamma-ray (GR), bulk density (RHOB) and effective porosity (PHIE)) vs. core-plug porosity and permeability measurements were generated using Prism to assess which log measurements best predicted core observations R-square (R^2) as defined by correlation coefficients of regression equation fit to each cross plot. The regression equation might then be used to predict permeability and porosity for uncored wells.

4. Results and interpretations

The core and log data were matched with published data and log signatures [21-22] to interpret the depositional environments for the study intervals. The core data for wells WB-37 and WB-49 were used as the basis for lithofacies characterization. In some cases, sandy lithofacies with low gamma-ray value were not the best reservoirs because of extensive calcite cementation, which is not reflected in the gamma-ray logs.

The measured porosity ranges between 28 and 35% and the permeability between 305 and 5,041 md. The porosity and permeability values reflect better grain sorting, limited amounts of clay within pore throats and spaces, fewer mudstone layers and other permeability barriers, and absence of calcite cementation in this facies. Many of the sandy lithofacies within the E-01 to D-07 intervals are flow units. Porosity vs. permeability cross-plots (Fig. 5) for various lithofacies at WB-Field shows the considerable range of petrophysical values for the E-01 to D-07 intervals. Porosity and permeability measurement for the D-07 interval was taken at every foot while there are selective measurements in the E-01 interval which may have cause an increase in the average porosity and permeability values in E-01 interval.

A cross-plot of core porosity and core permeability for the D-07 interval reveals an excellent correlation between these two parameters (Fig. 6) with a thickness of feet, R^2 value of 0.91. Log-derived effective porosity (PHIE), gamma-ray and bulk density logs were cross-plotted against the core data to determine which of the log properties relate best to the actual core measurements. The bulk density measurements were found to correlate best with the core measurements, with a R^2 value of over 0.86. The regression line equation was used to derive porosity and permeability from bulk density measurements. The derived porosity and permeability values correlate well with the actual core data. The same procedure was carried out on the E-01 interval. Again the bulk density log correlated best with the core measurements. The thickness of fit (R^2) between the core-derived porosity and permeability and core measurements were greater than 0.8 in both cases.

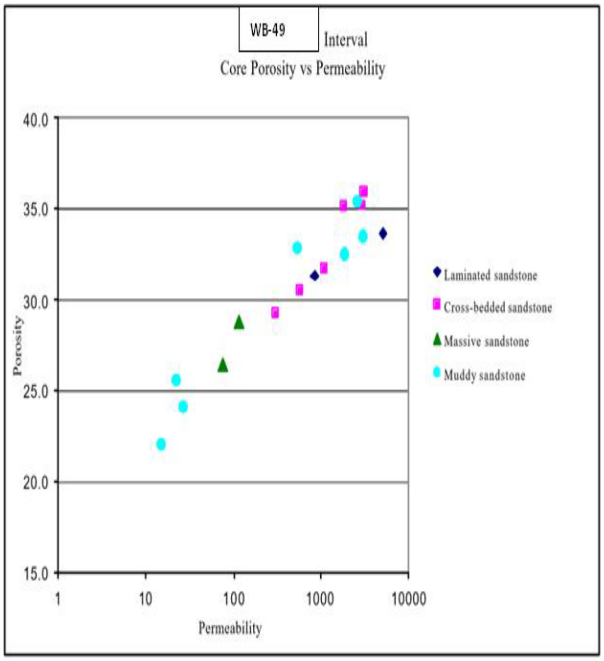

Fig. 5. (A). Core porosity vs. permeability plot as a function of lithofacies in the E-01 interval.

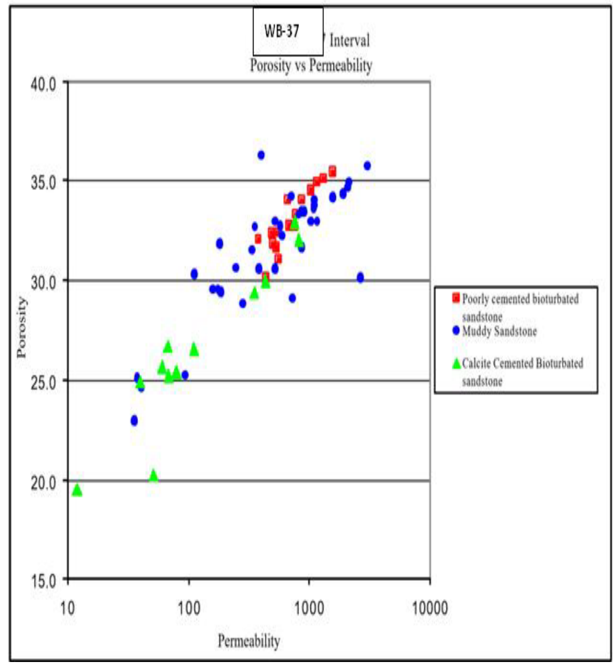

Fig. 5. (B) Core porosity vs. permeability plot in the D-07 interval.

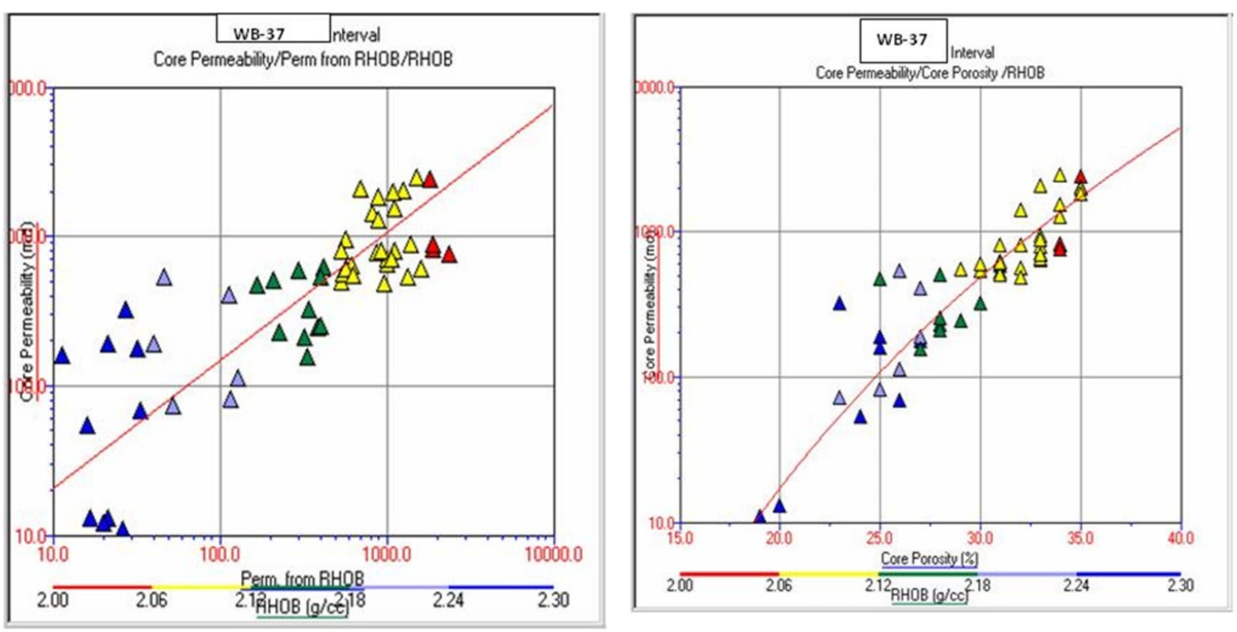

Fig. 6. (A) Cross plot of core porosity and permeability from the D-07 interval in WB-37 well.

The gamma-ray is not a reliable indicator of porosity and permeability. This is mainly because the gamma-ray log is unable to detect calcite cementation in the sands, which have significant effects on porosity and permeability. Gamma-ray logs are also poor indicators of porosity and permeability in shaly sands, especially in the bioturbated sandstone lithofacies, where extensive bioturbation has destroyed all primary sedimentary structures and completely mixed the clay with the sands. The neutron porosity log also is an unreliable indicator of porosity and permeability. The PHIE log also gave pessimistic porosity estimates especially in the E-01 and D-07 intervals probably because the Shale effect was not properly corrected for in the intervals. An algorithm was developed to obtain porosity and permeability from bulk density readings, and comparison of the different log measurements, core and log porosity, and the bulk-density derived porosity and permeability for the WB-49 and WB -37 wells (Fig. 7).

The equation for the derivation of porosity from RHOB log measurements is of the form $y = 135 + 50rhob$.

A plot of the measured porosity vs predicted porosity gave a R^2 value of 0.84 in WB-37 (D-07 interval) and 0.87 in the WB-49 (E-01 interval).

The equation for deriving permeability using RHOB is $y = 6.10^{15}.10^{-6.2.rhob}$

The bulk density values were used directly in the derivation of porosity. The more traditional method of first calculating density porosity from bulk density using the equation, $\varphi_{density} = (\rho_{ma} - \rho_b)/(\rho_{ma} - \rho_f)$ where φ density is density porosity (decimal percent), ρ_{ma} is matrix density (grams per cubic centimeter; g/cc), ρ_b is bulk density (g/cc), and ρ_f is fluid density (g/cc) was not used so that a single equation can be used irrespective of the matrix and fluid densities. Porosity derived from bulk density correlates better with core porosity than the effective porosity, especially in the E-01 and D-07 intervals as effective porosity is derived using a combination of neutron and density readings. It is also especially useful in intervals with calcite cementation, as the density tool is to detect the presence of calcite cement that significantly reduces porosity and permeability. The excellent correlation between core porosity and permeability allows the derivation of permeability also form bulk density. The same equation works well for both the E-01 and the D-07 intervals. R^2 from plots of core measurements vs. derived measurements is over 0.84. The limitations to the application of the porosity and permeability predictor includes: (1) drastic change in fluid density and (2) non-linear relationship between porosity and permeability.

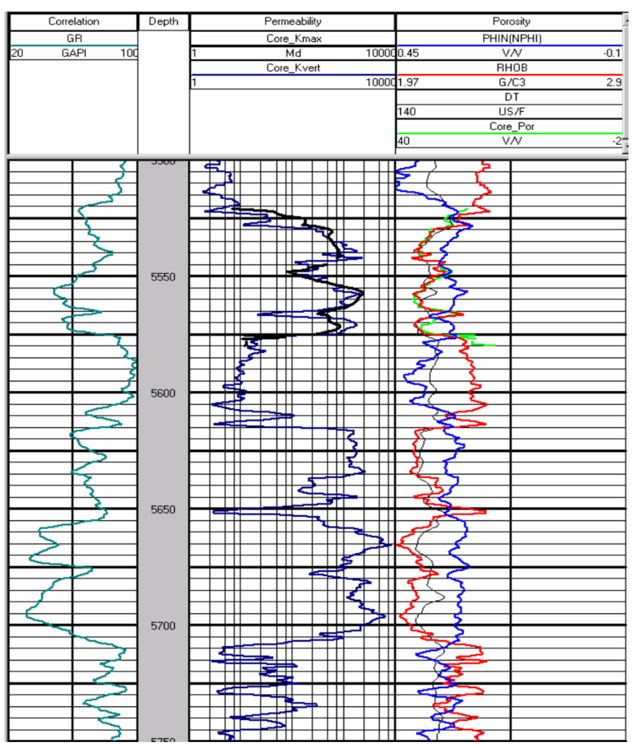

Fig. 7. Log of WB-37 well showing the different petrophysical properties of the intervals.

5. Conclusions

There is a relationship between lithofacies, depositional environment, and petrophysical properties. The lithofacies with the highest measured core porosity and permeability values is the cross-bedded, well-sorted, upper-shoreface sands with average porosity and permeability of 32% and >1,500 md, respectively. The poorest quality reservoir sands are those of the calcite-cemented lower shoreface facies with average porosity and permeability of 25 and 100md. Comparison of core porosity and effective porosity (PHIE) log values for the D-07 and E-01 intervals shows that the PHIE log grossly underestimates the actual porosity values by as much as nine porosity units. Bulk density logs are the best predictor of petrophysical property with R^2 values greater than of 0.8. The gamma-ray log, while indicative of the amount of shaliness and depositional energy, is unable to capture the post-depositional processes that affect reservoir quality.

The relatively low resistivity readings in the D-07 and the E-01 intervals are due to a combination of clay content and the presence of conductive siderite nodules. Though the gamma-ray log suggests high Shale/clay content, extensive bioturbation in these lower shoreface reservoirs have actually created an increase in the porosity and permeability through the homogenization of the clay and sand laminations.

An algorithm was developed to estimate porosity and permeability from log measurements. Various logs were investigated, but the bulk density log was shown to be the best predictor of porosity and permeability. This has particular application in non-core wells and provides an alternative to gamma-ray logs for estimating reservoir potential. Shaly reservoirs such as the D-08 and E-01 intervals could be more accurately evaluated at WB-field and possibly elsewhere in the Niger Delta Basin using this bulk density/ porosity-permeability relationship to determine the productivity of these reservoirs.

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To whom correspondence should be addressed: Ikechukwu O. Azudi, Department of Geology, Chukwuemeka Odumegwu Ojukwu University, Uli, Anambra State, Nigeria, E-mail: on.ikegwuonu@coou.edu.ng