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Petrophysical Evaluation of Reservoir Sand Units in "Hum" Field Onshore Niger Delta Basin using Well log Data

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Abstract

This study presents an integrated petrophysical evaluation of the Hum Field located in the Niger Delta Basin, with the primary objective of delineating potential hydrocarbon-bearing zones and assessing the reservoir quality of key sand units. The analysis was based on the interpretation of composite well log suites from multiple wells across the field. Three prominent reservoir intervals—designated A200, B400, and C600 sands—were identified and evaluated using a combination of qualitative and quantitative techniques. Gamma ray log motifs were employed to infer lithofacies characteristics and reconstruct the gross depositional environments of the identified sand bodies. The log patterns suggested deposition within high-energy clastic environments, specifically beach, channel, and shoreface settings, which significantly influence reservoir quality. Petrophysical parameters including volume of shale (Vsh), net-to-gross ratio (NTG), effective porosity (Øe), and water saturation (Sw) were computed using industry-standard empirical models to evaluate the reservoir units. The results indicate that the A200, B400, and C600 sands exhibit favorable reservoir properties, with average effective porosity values of 0.20, 0.30, and 0.25; net-to-gross ratios of 0.74, 0.83, and 0.84; and shale volumes of 0.26, 0.17, and 0.16, respectively. These values reflect well-developed, clean sand reservoirs with minimal shale interference, suggesting high storage capacity and good reservoir continuity. The computed water saturation values further confirmed the presence of hydrocarbons, with testing results indicating that the A200 and C600 sands are oil-bearing, while the B400 sand contains gas. Permeability estimates derived from porosity-permeability correlations suggest that the reservoirs possess fair to good pore connectivity, enhancing fluid flow and supporting potential for commercial production. The variation in reservoir quality across the intervals is attributed to differences in depositional environment and diagenetic history.

Keywords

Petrophysical evaluation,
Reservoir properties,
Well log data,
Niger Delta Basin.

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1 Introduction:

A greater portion of the world's energy mix will come from hydrocarbon sources and its derivatives coming from the deeper portion of the various hydrocarbon habitats. It has therefore become imperative to apply newly emerging exploration and production tools and skills to adequately harness these resources (Rotimi and Olori, 2010; Opara et al., 2021; Osaki et al., 2021). As shallow hanging easy-to-find oil and gas pools diminish around the globe, exploration and production companies are forced to pursue and develop smaller and more complex reserves located at greater depths beneath the surface (Dim et al., 2020; Okewu et al., 2024). In order to achieve new hydrocarbon resource addition in a complex setting like the Niger Delta Basin, there is a need to reassess the already explored areas using improved technologies (Opara et al., 2021; Onyekuru et al., 2022).

Decades of oil and gas extraction from the Niger Delta Basin has resulted in depleted hydrocarbon reservoirs in over 300 mature oilfields in the onshore and offshore portions of the basin. Nevertheless, it is believed that undiscovered oil and/or gas fields/pools still exist in the Niger Delta Basin. However, finding the subtle reserves that can match a global demand require modification of earlier conventional techniques and concepts (Ejeh, 2010). Detailed understanding of the underlying geology, variability in subsurface formation properties, and distribution of reservoir sand bodies is key accurate prediction of the hydrocarbon potentials and reserve estimation of a petroleum field. Information gathered from cores, seismic, well logs and other subsurface data help to resolve the structural and stratigraphic complexities for enhanced characterization the hydrocarbon reservoirs (Tinker, 1996).

Reservoirs in the Niger Delta Basin exhibit a wide range of complexities in sedimentological and petrophysical characteristics due to facies variability. Accurate prediction of the spatial distribution of petrophysical properties within a heterogeneous reservoir is affected by significant uncertainties. In order to avoid the bias, knowledge of rock matrix and pore fluid types is required to allow for proper calibration or correction of the estimated values. Thus, the application of integrated formation evaluation techniques can significantly improve the accuracy of the estimated reservoir properties. Such integration is a key step to reducing uncertainties in the static properties of a reservoir (Weber, 1971; Aigbedion and Iyayi, 2007; Abiodun, 2013).

This present study is focused on evaluating the petrophysical parameters of hydrocarbon-bearing sand units estimated from well log data to understand the spatial distribution of reservoir properties in a mature producing field, onshore Niger Delta Basin, for optimum hydrocarbon recovery.

2. Location and Geology of the Study Area

The "Hum" Field is located in the Northern Delta Depobelt of the Niger Delta Basin in a land environment (Fig. 1). The Niger Delta Basin which covers an area of about 7500 km^2 is a large acute delta extending between longitude 3°E and 9°E and latitudes 4°N and 8°N (Doust and Omatsola, 1990). The province contains known resources (cumulative production plus proved reserves) of 34.5 BBO and 93.8 TCFG (Petroconsultants, 1996).

The Niger Delta Basin developed in the Cenozoic times at the southern edge of the Benue Trough where it intersects with the South Atlantic Ocean, at the tripartite junction that forms the point of separation between South America and African Plates in the Late Jurassic. Progradation of the deltaic deposits in the basin has been towards the southwest direction from the Eocene to the present, generating depobelts that represent the most active parts of the delta at each stage of its history. The onshore portion of the Niger Delta Basin is defined by the geology of southern Nigeria and southwestern Cameroon. The northwestern limit of the basin is the Benin flank, an east-northeast pivot line that forms the edge of the Western Nigerian Basement. The Cretaceous sediments of the Abakaliki Anticlinorium form the northeastern border, while the east-southeast border is defined by the Calabar Flank (Chidiadi and Okoro, 2015). The offshore boundary of the basin is defined by the Cameroon Volcanic Line (CVL) to the east, while the Dahomey Basin forms the western boundary (Short and Stauble, 1967).

Three main lithostratigraphic units have been identified in the Niger Delta Basin (Short and Stauble, 1967; Doust and Omatsola, 1990). These include the Akata, Agbada, and Benin Formations (Fig. 2). According to Knox and Omatsola (1989) these lithostratigraphic units constitute the complex prograding deltaic wedge of clastic sediments in the Niger delta Basin. Regional fault-bounded depo-centers controlled depositions in the delta, and also influenced the various depositional environments in which the sediments were laid down (Doust and Omatsola, 1990; Reijers, 2011).

The oldest lithostratigraphic unit in the Niger Delta Basin is the Akata Formation. It is composed of dark grey shales, silts and sand lenses or turbidite deposits. Murat (1972) interpreted these sediments to be open marine deposits, with estimated thickness of about 6.4 km at the central of the delta. The Akata Formation is the main source kitchen for hydrocarbon generation in the Niger Delta Basin. It is overlain by the Agbada Formation which is made up of sandstones, shales, and silt intercalations. The formation replicates depositions in a riverine or deltaic environment, with a thickness of about 3.9 km. The Benin Formation is the youngest depositional unit in the Niger Delta Basin. It consists mainly of coastal plain sands and alluvial deposits. It is the uppermost part of the Niger Delta clastic wedge, about 1.4 km in thickness (Doust and Omatsola, 1990; Tuttle et al., 1999; Abraham-A and Taioli, 2019).

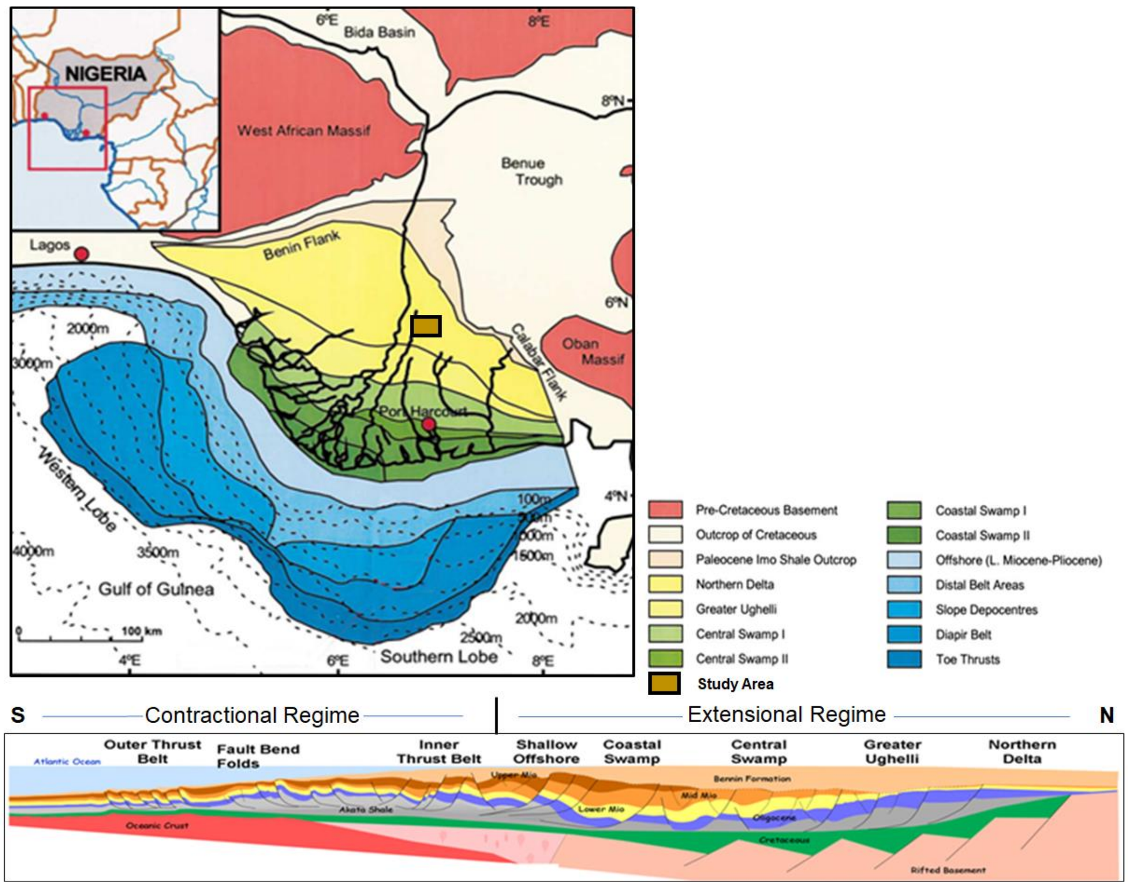

Figure 1. Schematic Niger Delta Regional Dip Cross-section Showing Structural Belts (Modified after Shannon and Naylor, 1989; Hooper et al., 2002).

3. Materials and Methods

3.1 Dataset

The dataset used for this work include well header and well deviation data, composite log suites from three wells logged with gamma ray, neutron, sonic, density and resistivity logs. The data was quality check before loading it into Petrel^{TM} software for further analysis and interpretation. The wells were renamed Hum-01, Hum-02, and Hum-03 for proprietary reasons (Fig. 3).

3.2 Methods

The basic analysis procedure used in the analysis and interpretation of the data include well log facies analysis, well log correlation, and petrophysical analysis.

3.2.1 Well log Facies Analysis

The gamma ray log signatures were analyzed to identify the various lithofacies penetrated by the wells, in order to understand the interaction between the myriads of depositional environments in which the sediments were deposited. Each facies are a representation of the depositional environment that prevailed at the time the sediments were formed. Thus, they are distinct rock types in terms of character and appearance, and they usually replicate the original depositional conditions at the time of formation of the sediments. This makes them unique features that can be easily distinguishes from other associated rock units or adjacent units (Selley, 1978; Murkute, 2001). In this study, the gamma ray log motifs were used to make inferences regarding the variations in sediment grainsize and depositional energy. This gave insights into the depositional environments of the sediments according to the model propounded by Emery and Myers (1996).

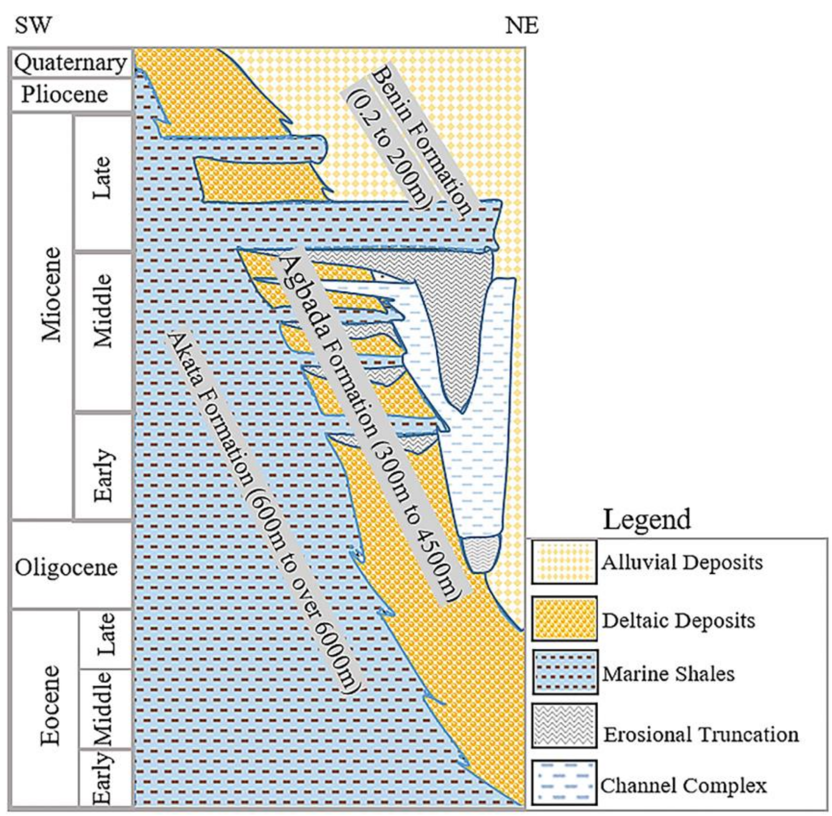

Figure 2. Lithostratigraphic successions of the Niger Delta Basin (modified after Doust and Omatsola, 1990; Abraham-A and Taioli, 2019).

3.2.2 Well Log Correlation

Lithological correlation between the wells was established using the marker shale identified in wells based on its high gamma ray and low resistivity signatures. This aided the delineation of appropriate sand markers chosen in order to define the various reservoirs and sands of interest. The hydrocarbon bearing sands were also noted for the evaluation of reserve potentials of the field. The reservoir sand units were delineated in True Vertical Depth Sub-Sea (TVDSS), while the marker shales were correlated using the log motifs. Well correlation helped in determining the direction of thickness of sand being mapped and the lateral continuity of these reservoirs.

3.2.3 Petrophysical Analysis

Petrophysical evaluation techniques were used to construct logs of volume of shale (V_{sh}), net-to-gross (NTG), water saturation (S_w), effective porosity ($Ø_e$), and permeability (K). This procedure comprised the following steps:

1. generation of V_{sh} from gamma ray logs using linear shale index.
2. porosity estimation from density logs.
3. computation of net-to-gross from V_{sh} logs.
4. water saturation (S_w) and fluid corrected effective porosity using the Simandoux water model
5. permeability derivation from logs using the equation of Coates and Dumanoir (1981).

These petrophysical properties were determined from well logs in order to understand the distributions of these parameters across the field. This was preceded by thorough quality-check and control of the well data used in this study, and then applying corrections where necessary. The shale, clean sand, and sand-clay trends were then determined and used in the petrophysical analysis to estimate clay volume, porosity, net-to-gross and water saturation parameters for the selected reservoir sands of interest. The obtained values were populated throughout the study area by modeling.

3.2.3.1 Determination of Shale Volume

The volume of shale, which is the percentage of shale contained in a sandstone or heterolithic reservoir, was calculated using the Larionov (1969) equation for Tertiary rocks

$$V_{sh} = 0.083*(2^{3.7*I_{GR}} - 1) \quad (1)$$

where I_{GR} is the gamma ray index and is given by:

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

GR_{log} is the gamma ray reading of the formation, GR_{min} is the minimum gamma ray reading (sand baseline) and GR_{max} is the maximum gamma ray reading (shale baseline).

3.2.3.2 Determination of Total Porosity and Effective Porosity

Total and effective porosity was estimated from the density, neutron, and sonic logs. It is generally accepted among geoscientists that porosity calculation from bulk density logs is more accurate (Rider, 2006; Calderon and Castagna, 2007; Issler, 1992; Horsfall et al., 2013). To calculate the porosity (Ø), the rock matrix density (ρ_{ma}), the fluid density (ρ_f), and the bulk density (ρ_b) was used. The average rock density in the sandstones research reports is 2.66gcm^{-3}. The average rock density in the shales is 2.65gcm^{-3}. The fluid density depends on whether the well encountered water or hydrocarbons. This was determined by the electrical resistivity log. The hydrocarbon density was calculated from composition and phase considerations, oil = 0.80 gcm^{-3} and gas = 0.6 gcm^{-3}. The water density used was 1 gcm^{-3}. Porosity was determined from the formula (Wyllie et al., 1956):

$$\emptyset_{density} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \tag{3}$$

where ρ_{ma} = matrix (or grain) density, ρ_f = fluid density and ρ_b = bulk density (as measured by the tool and hence includes porosity and grain density.

Effective porosity was calculated using the equation given below:

$$\emptyset_e = (1 - V_{sh}) * Por\_den \tag{4}$$

3.2.3.3 Water Saturation Estimation

Determination of fluid saturation in the reservoirs was achieved using the Simandoux water saturation model (Simandoux, 1963) which considers shaly contents of the sand units encountered in the Niger Delta Basin. The equation is given as follows:

$$\frac{1}{R_t} = \frac{\emptyset_e^m * S_w^n}{a * R_w} + \frac{V_{sh} * S_w}{R_{sh}} \tag{5}$$

where R_t is the true formation resistivity, $\emptyset_e$ is the effective porosity, S_w is the water saturation of the uninvaded zone, V_{sh} is the volume of shale, R_w is the resistivity of formation water, R_{sh} is the resistivity of shale, n is the saturation exponent, m is the cementation factor; and a is the tortuosity factor.

3.2.3.4 Net Pay Estimation

Calculation of the net pay was achieved using field-specific net pay cutoffs. Cutoff criteria used are water saturation < 50%, porosity > 10%, and volume of shale < 40%.

Net-to-Gross (NTG), which is the ratio of the thickness of the clean, porous, permeable, and productive (Net) reservoir sand to the total (Gross) reservoir thickness, was determined using the algorithm:

$$NTG = IF\,(V_{sh} <= 0.40, (1 - V_{sh}), 0) \tag{6}$$

It is usually not constant across a reservoir and may change over a short lateral distance from 1.0 (clean reservoir) to 0.0 (non-reservoir). Net pay is the portion of the net reservoir containing petroleum and from which petroleum will flow.

Reservoirs with low or unpredictable N/G ratios often require large number of wells to optimize recovery.

3.2.3.5 Determination of Permeability

Permeability values for the reservoir zones were determined by first of all estimating the Formation factor (F) for shaly sands using the equation of Berg (1986) which is given as:

$$F = \frac{1.65}{\emptyset^{1.33}} \quad (7)$$

Then, the formation factor (F) was related to irreducible water saturation using the equation:

$$S_{wi}^{2} = \frac{F}{2000} \quad (8)$$

The widely used Coates and Dumanoir (1981) equation which relates permeability to irreducible water saturation and porosity was then applied only in hydrocarbon-bearing zones. The equation is given below:

$$K = 100\, x \frac{\emptyset^{2} x (1 - S_{wi})}{S_{wi}} \quad (9)$$

where K = permeability in millidarcies, ϕ = effective porosity as a bulk volume fraction and S_{wi} = irreducible water saturation.

4. Results and Discussion

4.1 Lithofacies and Depositional Environment Interpretation

Lithofacies identified in the study area representing the various depositional environments in which the sediments were formed are shown in figure 3. The lithofacies analysis was used to lay emphasis on the paleo-depositional processes that prevailed at the time of deposition of the sedimentary successions penetrated by the wells. The identified gamma ray curves in the studied wells include cylindrical (or boxcar), funnel, bell, symmetrical, and serrated (or irregular) log shapes. The log patterns represent sediment depositions in fluvial channel, shoreface, deltaic channel, storm dominated shelf, or reworked deposits of the shoreface delta (Doust and Omatsola, 1990; Cant, 1992).

Figure 4 shows the conceptual depositional model and the dominant lithofacies types encountered at different intervals beneath the study area. The lithofacies were generally divided into four main groups, including the Massive Sandstone Facies, Heterolithic Facies, Shaly Sandstone Facies, and Mudrock Facies. These lithofacies units replicates sediments deposited by fluvial channels in beach settings, tide dominated shoreface deposits, and open marine sediments.

4.2 Lithological Correlation and Reservoir Delineation

Figure 5 is the well log panel showing the correlation of the three wells evaluated in this study and the delineated reservoir sands of interest. The log correlation aided in the identification of hydrocarbon-bearing sand units based on the integration of gamma ray, resistivity, density, and neutron logs. It also enabled the isolation of sands from shale sequences in the field.

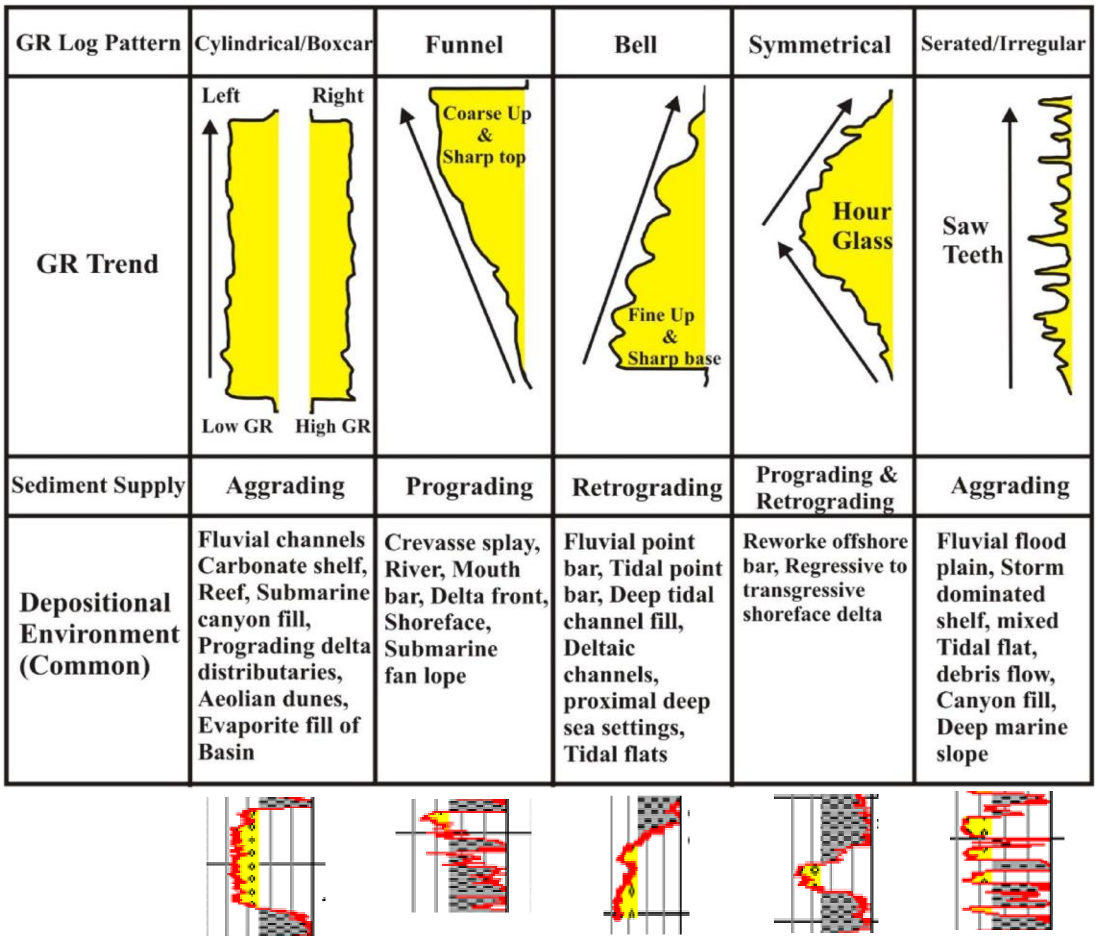

Figure 3. Common sedimentological facies associated with various gamma ray log shapes (after Cant, 1992).

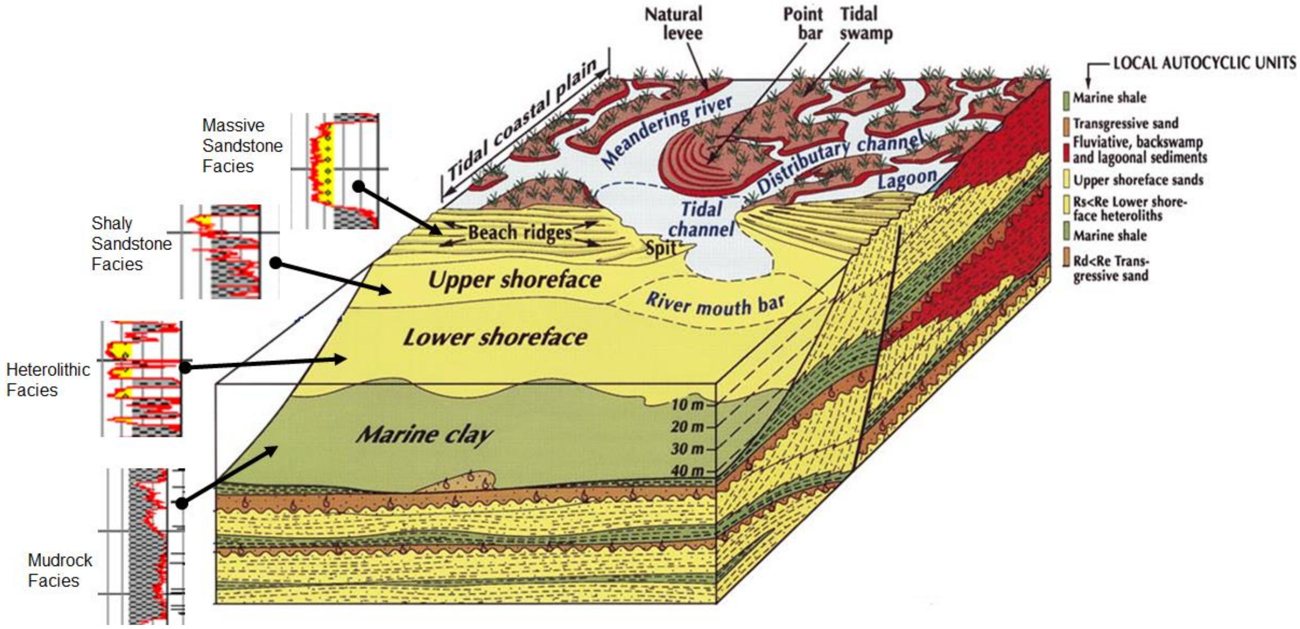

Figure 4. Conceptual model showing the depositional environments interpretation of the sediments in the study area (after Reijers, 2011).

The sand units of interest were mapped and named as A200 Sand, B400 Sand, and C600 Sand. The reservoirs were further evaluated to understand the lateral and vertical variabilities and distributions of petrophysical properties beneath the study area. Inferences on the fluid type contained within the reservoirs were made based on observations of the density-neutron crossovers (gas effect) and the resistivity kick within the reservoir interval.

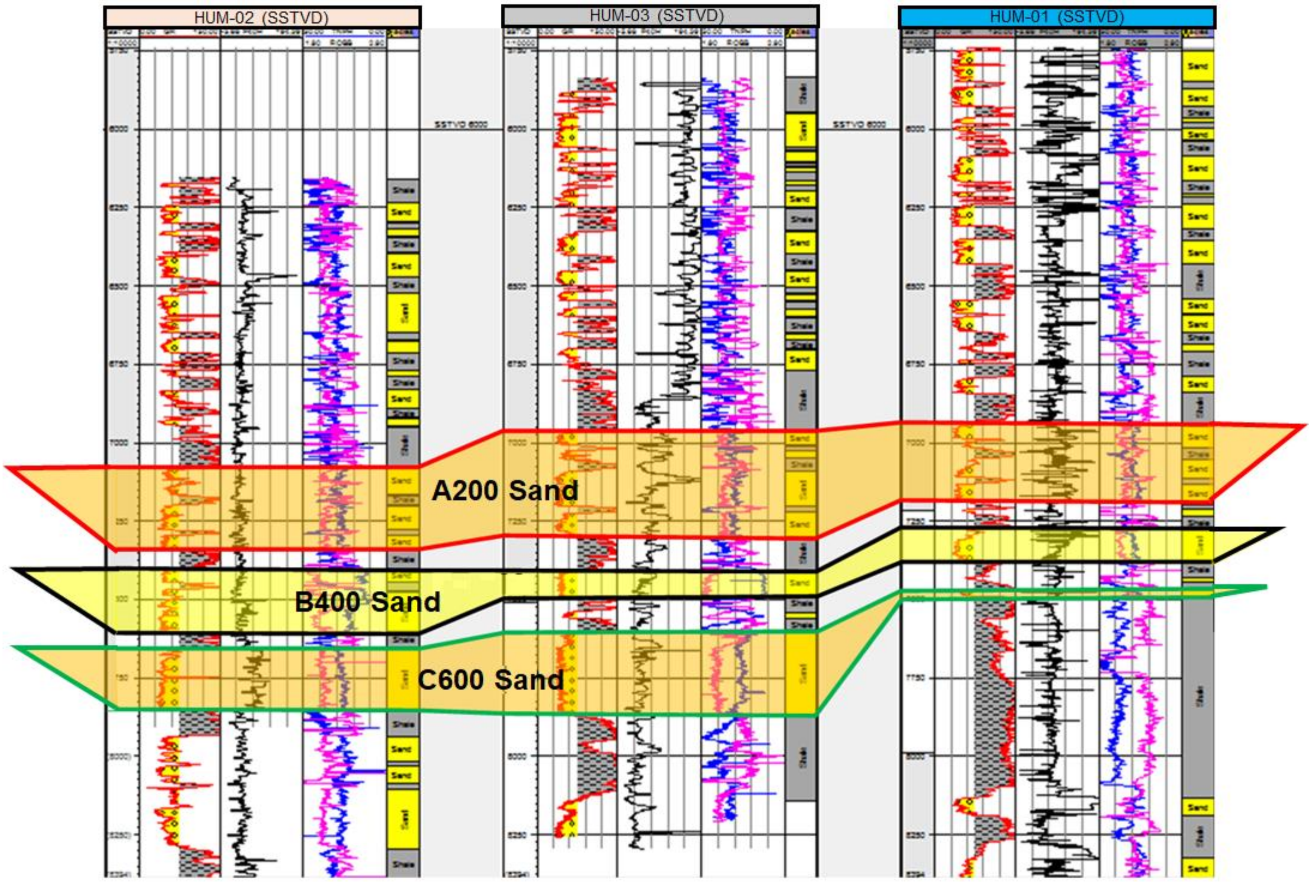

Figure 5. Well log panel showing the correlated reservoir sands in the study area.

4.3 Petrophysical Properties of the Reservoir Sand Units

Tables 1 summarizes the estimated petrophysical properties of the evaluated hydrocarbon-bearing units in the study area. The three reservoir sands were designated as potential prospective zones owing to their characteristic properties such as volume of shale, net-to-gross, effective porosity, and water saturation. The reservoirs were tested by the three (3) wells, and they showed different stratigraphic thicknesses in each of the wells. For instance, the Hum-001 well penetrated the A200 Sand between the depth of 7027 ft to 7279 ft; Hum-002 penetrated the same reservoir unit at the depth range of 7168 ft to 7423 ft, while Hum-003 encountered the A200 Sand the depth of 7043 ft to 7383 ft. The gross thickness of this reservoir in each of the wells is 252 ft, 255 ft, and 340 ft, respectively.

Table 1. Summary of estimated petrophysical properties of the delineated reservoir units in Hum Field.

Well Name	Zone	Fluid Type	Top (ft)	Base (ft)	Gross (ft)	Net (ft)	Av. NTG (v/v)	Av. Vsh (v/v)	Av. $Ø_T$ (v/v)	Av. $Ø_e$ (v/v)	Av. Sw (v/v)	Av. K (mD)
Hum-01	A200	OIL	7027	7279	252	181	0.72	0.28	0.24	0.18	0.14	13.34
	B400	GAS	7356	7468	112	91	0.82	0.10	0.30	0.24	0.05	24.02
	C600	OIL	7553	7571	18	14	0.79	0.21	0.24	0.19	0.21	10.18
Hum-02	A200	OIL	7168	7423	255	186	0.73	0.27	0.26	0.21	0.03	19.21
	B400	GAS	7489	7688	199	159	0.80	0.29	0.35	0.29	0.02	52.17
	C600	OIL	7736	7935	199	173	0.87	0.13	0.30	0.26	0.01	25.84
Hum-03	A200	OIL	7043	7383	340	258	0.76	0.24	0.26	0.21	0.11	18.28
	B400	GAS	7494	7577	83	72	0.87	0.12	0.41	0.36	0.14	67.22
	C600	OIL	7685	7959	274	238	0.87	0.13	0.33	0.29	0.14	47.50

The A200 Sand showed average NTG values ranging between 0.72 and 0.76, average V_{sh} values ranging from 0.24 to 0.28, and average $Ø_e$ values ranging from 0.18 to 0.21. The estimated average S_w values ranged from 3 to 14 %, while the average K values varied from 13.34 to 19.21 mD. The B400 Sand is characterized by average NTG values ranging from 0.80 to 0.87, average $Ø_e$ values ranging between 0.24 to 0.36, average V_{sh} values ranging from 0.10 to 0.29, and average S_w values ranging from 2 to 14 %. The estimated average K values for this reservoir unit varied between 24.02 to 67.22 mD. The average NTG values determined for the C600 Sand varied from 0.79 to 0.87; the average V_{sh} values ranged between 0.13 to 0.21, while the average $Ø_e$ values ranged from 0.19 to 0.29. The estimated S_w values ranged from 1 to 21 %, with the average K values ranging from 10.18 to 47.50 mD.

The overall low average water saturation values are indication that these reservoirs are highly saturated with more than 50% hydrocarbon. Analysis of the density, neutron, and resistivity logs revealed that the A200 Sand and C600 Sand contain gas, while the B400 Sand is saturated with oil (Fig. 6). The estimated high NTG, and $Ø_e$ values shows that the reservoirs are high quality sands, typical of channel, beach, or shoreface deposits. Sediments deposited in such settings have been classified sands of high reservoirs quality in the Niger Delta Basin (Doust and Omatsola, 1990).

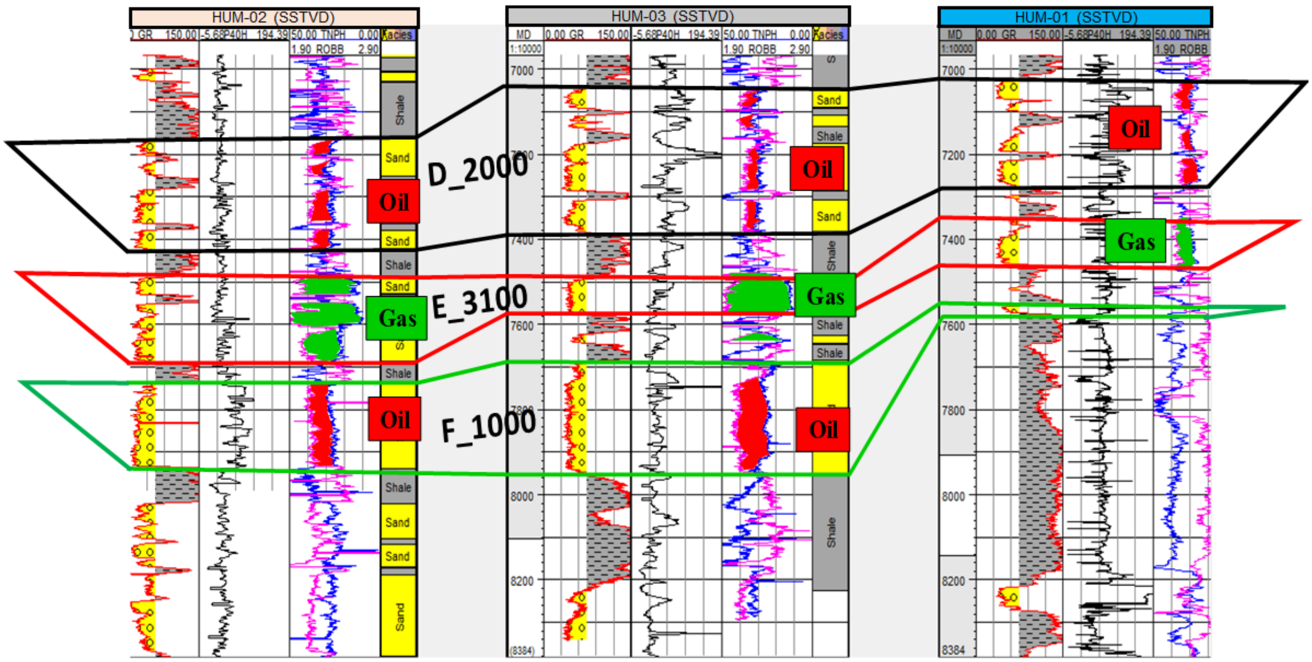

Figure 6. Well log panel showing the correlated reservoir sands in the study area.

5. Conclusion

Petrophysical evaluation of reservoir sand units in the Hum Field onshore Niger Delta Basin have been attempted in this study using wireline logging data from three wells. The underlying lithological units in the penetrated by the wells in the study area are predominantly sand and shale sequences of the paralic Agbada Formation, which is the main hydrocarbon-bearing lithostratigraphic unit in the Niger Delta Basin. Analysis of the gamma ray log responses revealed four lithofacies types, including the Massive Sandstone, Shaly Sandstone, Heterolithic, and Mudrock Facies. These facies associations reflected sediments deposited by fluvial channel systems in beach settings, tide dominated shoreface deposits, and open marine sediments.

Lithological correlation of the logs revealed three hydrocarbon-bearing sand intervals designated as A200 Sand, B400 Sand, and C600 Sand. The estimated petrophysical properties of these reservoir units showed that they are high quality sands characterized by average NTG values of over 0.70, average $Ø_e$ values of 0.18 and above, and S_w values less than 22 %, suggesting that they are saturated over 70 % hydrocarbons. Fluid type analysis showed that the A200 Sand and C600 Sand units contain gas, while the B400 Sand contain oil. The estimated average permeability of the reservoirs suggests moderate permeabilities for hydrocarbon extraction. Detailed reservoir characterization of the sand zones involving the integrated interpretation of 3D seismic, biostratigraphic and core data should be considered in order to have a full grasp of the lateral and vertical distribution of the petrophysical properties, as well as the geometry of the sand bodies beneath the study area.

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