

Reservoir Quality Assessment Using Petrophysical Analysis in Uzondu Field, Niger Delta Basin

Uzochukwu Chioma Omoja^{1*}, Gabriel Ndubuisi Egwuonwu¹, Francis Omonefe², Chukwudike Gabriel Okeugo³

¹Department of Physics and Industrial Physics, Nnamdi Azikiwe University, Awka, Nigeria

²Department of Geology, Federal University, Otuoke, Bayelsa, Nigeria

³Department of Geology, University of Nigeria, Nsukka

*Corresponding Author: uc.omoja@unizik.edu.ng

ABSTRACT: Reservoir quality assessment using petrophysical analysis in *Uzondu* Field, Niger Delta Basin was carried out using Well log data. The target for this study was the Zone A-E (W, X, Y, Z series) reservoir sands of wells *Uzondu_A-E* with depth range of 8155ft to 12320ft across the five wells. Well log data were analyzed using Interactive Petrophysics (IP2018) software to evaluate key petrophysical parameters such as shale volume (Vsh), effective porosity (Φ_e), water saturation (Sw), permeability (via Timur's equation), and net-to-gross ratio for the Zones A-E (W, X, Y, Z series) reservoir units. The results indicate that *Uzondu_A* contains high-quality, hydrocarbon-bearing clean sandstones with high porosity (up to 0.40), very high permeability (up to 2,860 mD), and low water saturation. *Uzondu_B* shows good to very good reservoir properties with moderate heterogeneity, while *Uzondu_C* exhibits moderate to poor quality due to increasing shale content. *Uzondu_D* is interpreted as non-reservoir, and *Uzondu_E* represents a marginal, shale-dominated sector with high water saturation and low permeability. Lateral correlation demonstrates a core productive zone centered around *Uzondu_A* and *Uzondu_B*, with reservoir quality diminishing toward the field margins. The study concludes that reservoir quality in the *Uzondu* Field is primarily controlled by porosity and shale content, with fluid saturation exerting a secondary influence.

KEYWORDS: Reservoir quality; Petrophysical analysis; Net pay; Shale volume; Niger Delta Basin; *Uzondu* Field

I. INTRODUCTION

Reservoir quality assessment is a fundamental component of hydrocarbon exploration and production, as it directly controls the storage capacity, fluid flow behavior, and overall productivity of subsurface reservoirs. Accurate evaluation of reservoir properties such as porosity, permeability, fluid saturation, and lithology is essential for estimating hydrocarbon potential, designing optimal field development strategies, and minimizing exploration and production risks (Kumar *et al.*, 2018; Saadu and Nwankwo, 2018). In clastic depositional systems, particularly those of deltaic environments, reservoir quality is strongly influenced by depositional processes, diagenetic alterations, and structural controls. Petrophysical analysis of well logs remains one of the most effective tools for quantifying reservoir properties and evaluating their impact on reservoir performance (Uguru *et al.*, 2002). Petrophysical analysis provides a quantitative framework for evaluating reservoir properties using well log data. Through the integration of gamma ray, resistivity, density, neutron, and sonic logs, key parameters such as shale volume (Vsh), effective porosity (Φ_e), water saturation (Sw), and net-to-gross ratio (NTG) can be determined (Ubong *et al.*, 2017, Omoja and Obiekezie, 2021).

These parameters are critical in defining reservoir quality, identifying hydrocarbon-bearing zones, and estimating hydrocarbon in place (Abdolla, 2010). Log crossplots further enhance lithology and fluid discrimination, while cutoff determination refines net reservoir estimation. Variations in reservoir continuity, shale distribution, and fluid saturation across wells can significantly impact reservoir quality and volumetric estimates. Thus, a detailed petrophysical evaluation of the field is therefore required to delineate productive intervals, assess reservoir heterogeneity, and provide reliable input parameters for hydrocarbon volume estimation. This study aims to evaluate the reservoir quality of the *Uzundu* Field using comprehensive petrophysical analysis of available well log data. The specific objectives are to (1) characterize lithology and reservoir architecture, (2) quantify petrophysical properties across identified reservoir intervals, and (3) assess the relative influence of porosity, shale volume, and fluid saturation on reservoir quality. The results of this study will contribute to improved reservoir characterization and enhanced decision-making for field development within the Niger Delta Basin.

II. METHODOLOGY

A. Location and Geology of the Study Area

The *Uzundu* Field is located in the south-south part of the Niger delta. It covers a perimeter of 16,547 meters and an area of 14,688,531 square meters. The area lies approximately between latitudes 4°32'N and 4°33'N and longitudes 6°59'E and 7°01'E, and is referenced in the Geographic Coordinate System (GCS), WGS 1984 datum (figure 1), This region is part of the coastal swamp and mangrove belt of the Niger Delta and is characterized by low relief, dense vegetation, and an extensive network of creeks and waterways. The presence of multiple waterways reflects the fluvial–deltaic environment that dominates the Niger Delta and influences sediment deposition and reservoir development. The Niger Delta Basin sits on top of the Gulf of Guinea which is located on the edge of the West African continental margin (Doust and Omatsola, 1990). The structural traps in the Niger Delta basin resulted from tectonic, diapiric, gravitational and compactional processes over time followed by shale mobility deformation processes (Galloway, 1989). The Tertiary section of the Niger Delta is divided into three formations: Benin, Agbada (the reservoir rock) and Akata (the source rock and reservoir in deep offshore) Formations. The Akata-Agbada formations are the known tertiary Niger Delta petroleum system (Tuttle, *et al.*, 1999). The Akata Formation (Eocene-Recent) is the basal part or unit of the Tertiary Niger Delta complex (Okoli *et al.*, 2018). It is of marine origin and composed of thick shale sequences which on the basis of geochemistry are believed to be the source rock of the Niger Delta petroleum system. In the deepwater region of the Niger Delta, turbidite sandstone with minor amount of clay and silt compose the major reservoir units. The Akata Formation is believed to have formed during low stands when terrestrial organic matter and clays were transported to deep-sea waters characterized by low energy conditions and oxygen deficiency (Stacher, 1995; Inyang *et al.*, 2015). Majority of the key hydrocarbon-bearing reservoirs in the delta exist within the Agbada Formation (Eocene-Recent) and are commonly situated in zones with structural heterogeneity. The formation consists mostly of channel and shoreface sands with slight shales in the upper part, and intercalation of shales and sands in equivalent ratio at the lower part of the basin (Whiteman, 1982).

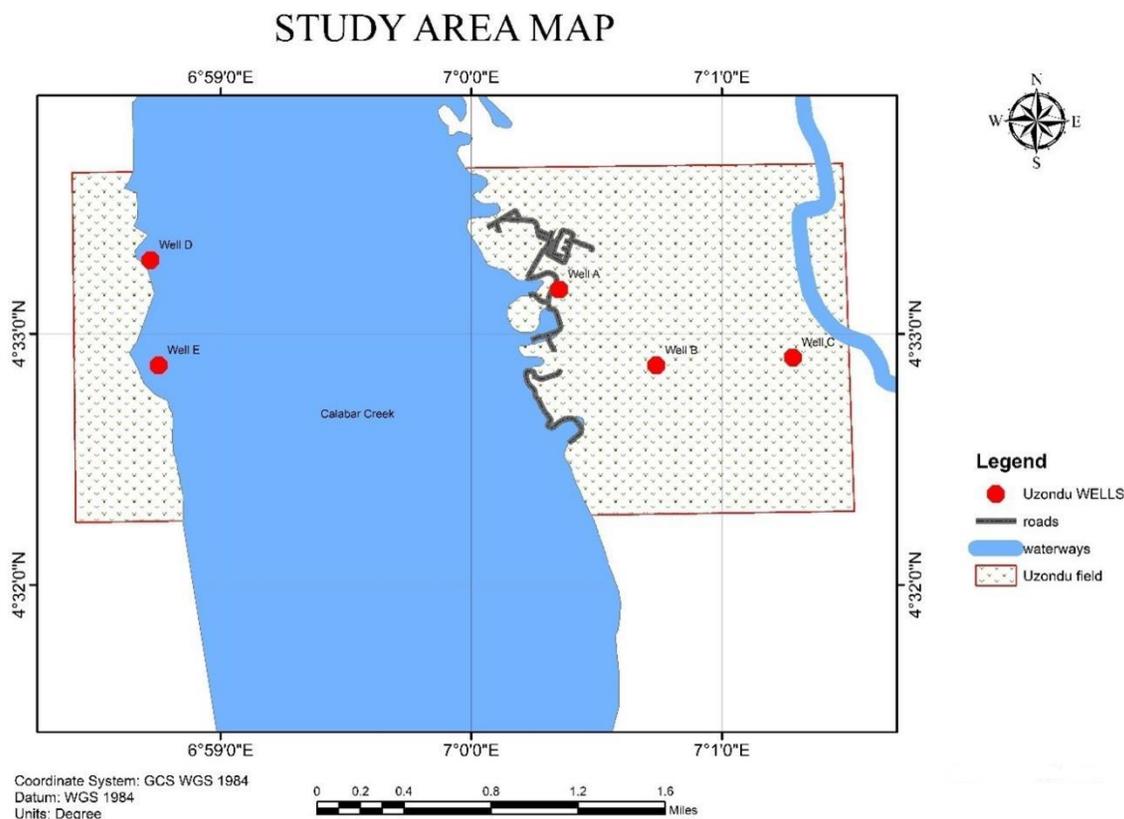


Figure 1: Map of the Study Area

B. Data Collection

The data set for this study was made available by Shell Petroleum Development Company of Nigeria Ltd (SPDC). A total number of 5 well data were provided for this research work. These logs include caliper (CAL) log, density (DEN) log, gamma ray (GR) log, p-wave log, resistivity (RES) log, and checkshot although not all well have these suites. Well tops and formation markers were used to define reservoir intervals and ensure stratigraphic consistency across wells. The five wells, namely *Uzongdu_A*, *Uzongdu_B*, *Uzongdu_C*, *Uzongdu_D* and *Uzongdu_E* are distributed across the field (figure 1) and serve as the primary subsurface control for this study. Wells *Uzongdu_A*, *Uzongdu_B*, *Uzongdu_C* are located on the eastern flank of the field, while *Uzongdu_D*, and *Uzongdu_E* are positioned toward the western flank, closer to the main creek. The spatial distribution provides good lateral coverage for geological correlation and reservoir characterization across the field. The wells penetrate to total depths of about 12,320 ft, indicating that multiple stratigraphic intervals within the Niger Delta succession are encountered. Interactive Petrophysics (IP2018), a smart petrophysical software developed for rigorous petrophysical analysis was used for the analysis. IP2018 was utilized to determine the petrophysical parameters in all wells such as net-to-gross, porosity, shale volume, permeability, hydrogen saturation and correlate the lateral extent of the reservoir across the field. The well logs were interpreted to define lithological units and detect potential hydrocarbon-bearing zones. Petrophysical analysis was carried out to quantify key reservoir properties. Porosity (ϕ) is the fraction of void space within a rock that can be occupied by fluids. It can be expressed as total

porosity (ϕ_T) or effective porosity (ϕ_E) (i.e., pore space connected and contributing to flow). Typical porosity estimation equations from density log

$$\phi_p = \frac{\rho_{\text{matrix}} - \rho_{\text{bulk}}}{\rho_{\text{matrix}} - \rho_{\text{fluid}}} \quad (1)$$

where ρ_{bulk} is bulk density (density log reading), ρ_{matrix} is matrix density (2.65 for Niger Delta), and ρ_{fluid} is fluid density. Effective porosity was derived from density since there is no neutron log.

The values of gamma ray index (IGR) obtained from gamma ray were used to calculate the volume of shale (Vsh) using Larionov's 1969 volume of shale formula for tertiary rocks

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

This equation is particularly used for tertiary Niger Delta. The volume of shale is used to correct for shale in the reservoir so as to obtain effective porosity.

Water saturation which is another important parameter in petrophysical evaluation was calculated using Archie's 1942 equation for water saturation in uninvaded zone (Archie, 1942)

$$S_w = \left(\frac{aR_w}{\phi^m R_t} \right)^{1/n} \quad (3)$$

where R_w is the formation water resistivity, R_t is the true formation resistivity (resistivity reading), a is tortuosity factor, m is cementation exponent, and n is saturation exponent. Permeability (k) which measures the ease with which a fluid (gas, oil or water) flows through connecting pore spaces of reservoir rocks was computed using Timur's 1968 equation:

$$k = 8581 * \frac{\phi_E^{4.4}}{S_{w_{irr}}^2} \quad (4)$$

III. RESULTS AND DISCUSSION

A. Petrophysical Analysis Result of the Study Area

Petrophysical evaluation was carried out on five wells (*Uzundu A–E*) to quantify reservoir properties including gross and net thickness, net-to-gross ratio (N/G), porosity (Φ), water saturation (S_w), shale volume (Vsh), and permeability (k). The interpretation integrates gamma ray, density, resistivity, saturation, and lithology logs (Figures 2–6), while reservoir continuity was assessed through well-to-well correlation (Figure 7). The results are summarized in Tables 1–5.

Petrophysical Characteristics of Uzundu_A

The petrophysical results for *Uzundu_A* (Figure 2; Table 1) reveal multiple high-quality sandstone reservoirs distributed between depths of approximately 8,155 ft and 11,464 ft. The identified reservoir zones (W, X, Y, and Z series) exhibit excellent net thicknesses, with most intervals showing net-to-gross ratios close to unity, indicating minimal shale intercalation and strong sand development. Average porosity values range from 0.155 to 0.401, reflecting moderate to very high porosity, typical of unconsolidated to weakly consolidated deltaic sandstones of the Niger Delta. Notably, zones W9500, W1000, X1000, and X2000 exhibit porosities exceeding 0.34 and very low water saturation ($S_w < 0.1$ in places), suggesting hydrocarbon-bearing, high-quality reservoirs. Shale volume is generally low to moderate ($V_{sh} < 0.1–0.15$ in most productive zones), confirming a dominance of clean sands.

Estimated permeability values range from 46 mD to 2,860 mD, with the highest permeability recorded in W9500 (2,860 mD) and W1000 (2,660 mD). These values indicate excellent pore connectivity and flow capacity, reinforcing the interpretation of these intervals as prolific

reservoirs. Deeper Z-series zones show a gradual decline in porosity and permeability, attributed to increasing clay content and burial compaction, yet several zones (e.g., Z1100 and Z1200) still retain fair reservoir quality. The reservoir in *Uzundu_A* are classified as having very good to excellent permeability values.

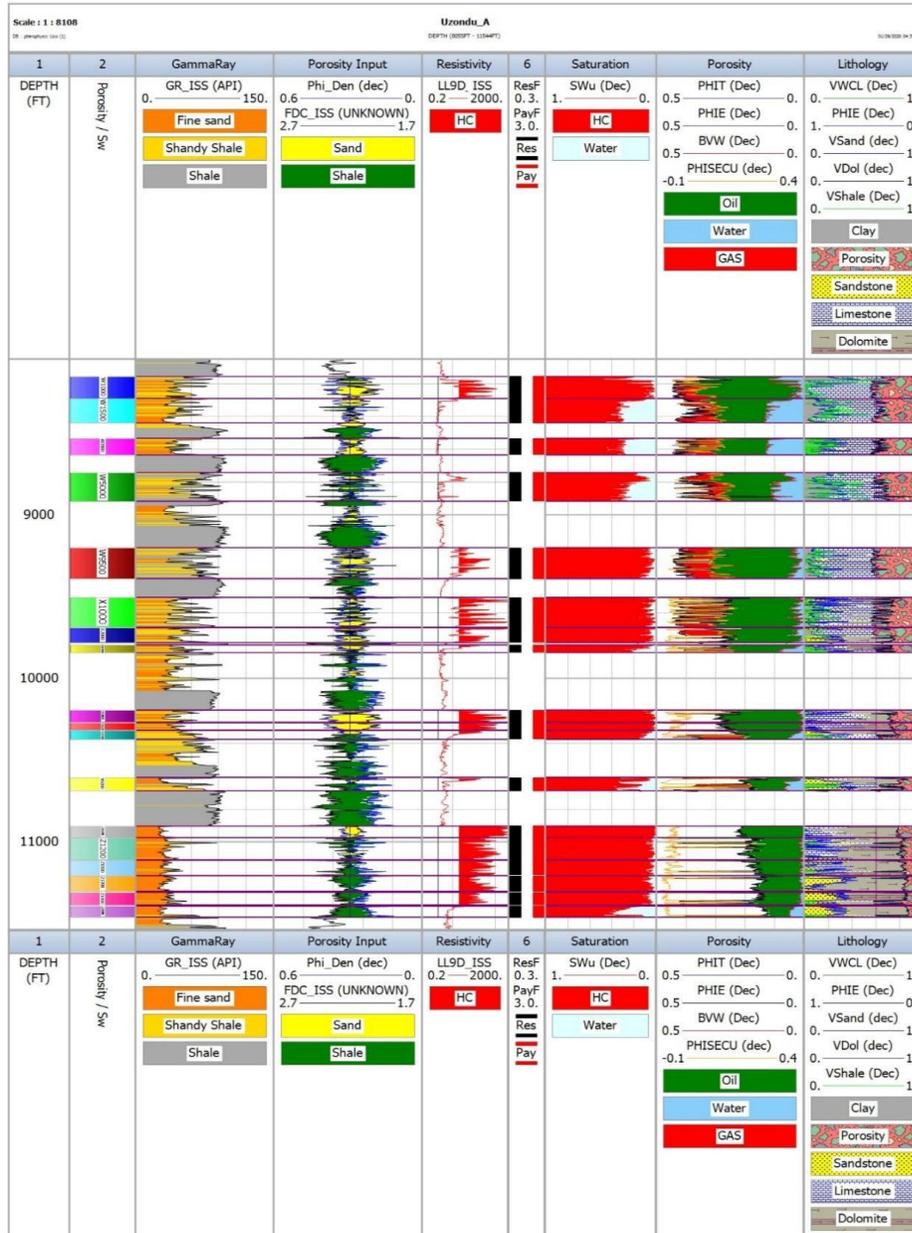


Figure 2: Petrophysical Result for *Uzundu_A*

Table 1: Petrophysical Parameters for *Uzundu_A*

Zone Name	Top (ft)	Bottom (ft)	Gross (ft)	Net (ft)	N/G	Av Phi	Av Sw	Av Vsh	Perm (mD)

W1000	8155	8290	135	135.00	1.000	0.399	0.100	0.105	2660
W1500	8293	8440	147	147.00	1.000	0.379	0.309	0.153	1800
W2000	8535	8636	101	101.00	1.000	0.373	0.323	0.097	1810
W5000	8744	8918	174	173.00	0.994	0.353	0.239	0.184	1150
W9500	9204	9393	189	188.50	0.997	0.401	0.074	0.078	2860
X1000	9508	9690	182	182.00	1.000	0.346	0.060	0.043	1305
X2000	9694	9784	90	90.00	1.000	0.349	0.062	0.049	1355
X3000	9798	9845	47	47.00	1.000	0.287	0.183	0.031	540
Y1000	10198	10272	74	74.00	1.000	0.275	0.037	0.002	470
Y1500	10273	10319	46	46.00	1.000	0.271	0.034	0.001	440
Y1700	10321	10374	53	53.00	1.000	0.308	0.110	0.072	700
Y6000	10610	10690	80	80.00	1.000	0.249	0.204	0.043	300
Z1100	10904	10975	71	71.00	1.000	0.216	0.017	0.000	190
Z1200	10975	11111	136	136.00	1.000	0.206	0.042	0.005	165
Z1500	11114	11208	94	91.75	0.976	0.183	0.045	0.003	115
Z1700	11208	11304	96	93.25	0.971	0.16	0.063	0.001	80
Z1900	11310	11387	77	77.00	1.000	0.184	0.068	0.005	117
Z2000	11394	11464	70	68.50	0.979	0.155	0.279	0.013	46

Petrophysical Characteristics of Uzondu_B

The petrophysical interpretation of *Uzondu_B* (Figure 3; Table 2) confirms the presence of laterally persistent reservoirs correlated with those in *Uzondu_A*. Net-to-gross ratios are generally high (0.91–1.00), indicating laterally continuous sand bodies. The W and Y reservoir series are absent in *Uzondu_B*. Porosity values range from 0.177 to 0.241, which are moderate to good, while water saturation values are generally low ($S_w < 0.1$ in most zones), suggesting hydrocarbon saturation. The Z1100 and Z1200 reservoirs are particularly notable, with low shale volumes (< 0.06) and relatively high porosity, resulting in high permeability values of 820 mD and 360 mD, respectively. The reservoirs in *Uzondu_B* are classified as having good to very good permeability values. Conversely, zones such as X2000 and Z2000 show elevated shale volumes and reduced permeability (≤ 95 mD), indicating shalier facies with diminished reservoir performance. Overall, *Uzondu_B* demonstrates good to very good reservoir quality, albeit with localized heterogeneity controlled by shale distribution.

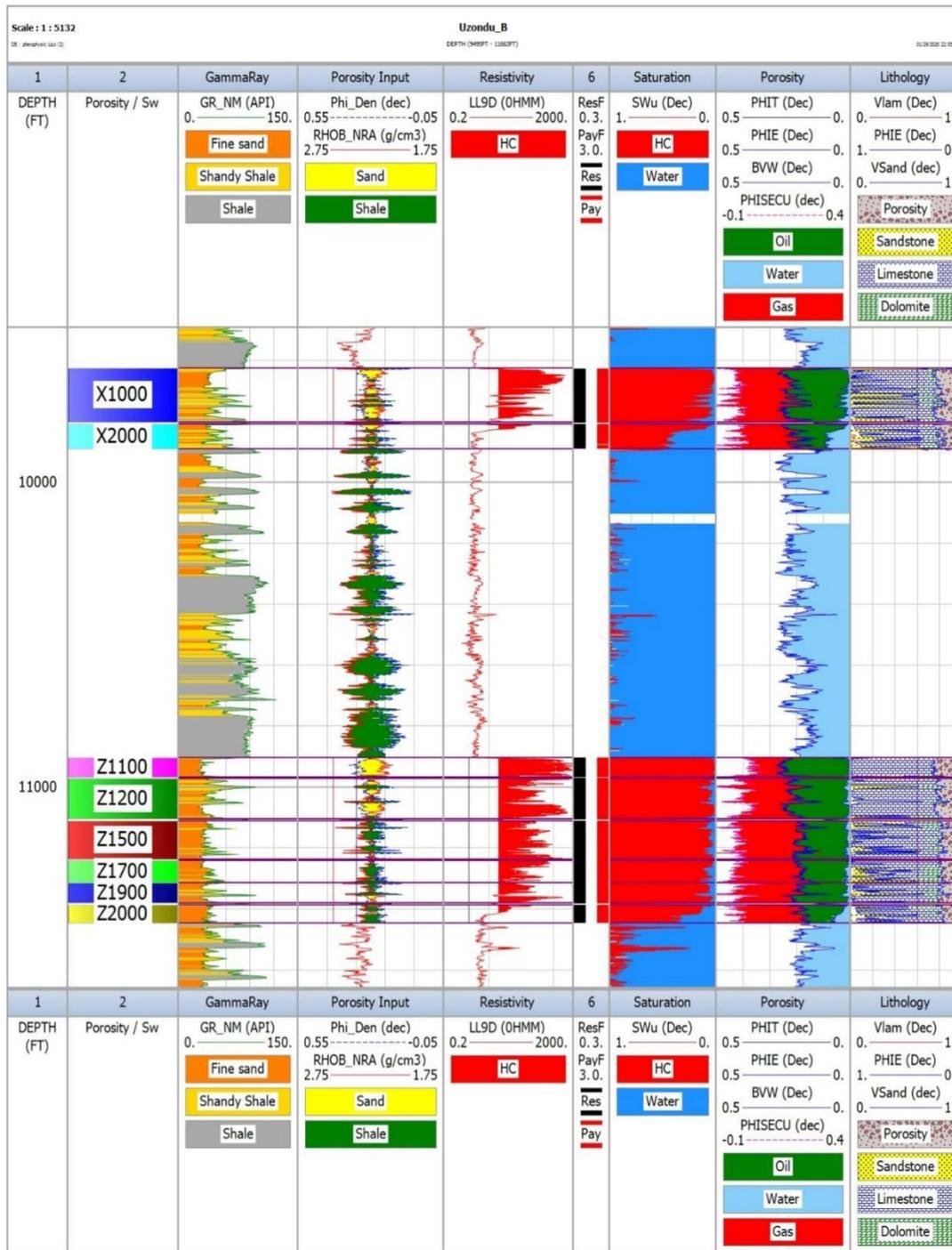


Figure 3: Petrophysical result for Uzundu_B

Table 2: Petrophysical parameters for Uzundu_B

Zone Name	Top (ft)	Bottom (ft)	Gross (ft)	Net (ft)	N/G	Av Phi	Av Sw	Av Vsh	Perm (mD)
X1000	9626	9803	177	174.25	0.984	0.222	0.082	0.011	520
X2000	9810	9890	80	72.75	0.909	0.206	0.334	0.057	95
Z1100	10905	10968	63	63.00	1.000	0.241	0.029	0.009	820
Z1200	10972	11106	134	133.75	0.998	0.208	0.054	0.013	360
Z1500	11111	11238	127	125.00	0.984	0.181	0.067	0.017	210
Z1700	11241	11315	74	73.5.00	0.993	0.179	0.077	0.016	190
Z1900	11315	11381	66	64.50	0.977	0.189	0.081	0.019	230
Z2000	11388	11446	58	56.50	0.974	0.177	0.231	0.059	75

Petrophysical Characteristics of Uzundu_C

Uzundu_C (Figure 4; Table 3) penetrates fewer reservoir intervals (W, X, and Y reservoir series were absent) compared to *Uzundu_A* and *Uzundu_B*, and overall reservoir quality is moderate to poor. Net-to-gross ratios decrease downward, particularly in Z2000 (N/G = 0.468), reflecting increased shale content and reduced sand development.

Porosity values range narrowly between 0.181 and 0.190, while shale volume increases significantly in deeper zones (Vsh up to 0.466). Consequently, permeability values are relatively low (85–220 mD). Although Z1500 and Z2000 display moderate permeability, their effectiveness as reservoirs is limited by high water saturation and reduced net thickness. These results suggest a facies transition from cleaner channel sands to more heterolithic or shaly deposits in this part of the field.

Table 3: Petrophysical parameters for *Uzundu_C*

Zone Name	Top (ft)	Bottom (ft)	Gross (ft)	Net (ft)	N/G	Av Phi	Av Sw	Av Vsh	Perm (mD)
Z1100	11151	11245	94	88.50	0.941	0.185	0.120	0.208	90
Z1200	11248	11351	103	98.75	0.959	0.181	0.153	0.191	85
Z1500	11363	11455	92	77.75	0.845	0.189	0.386	0.131	200
Z2000	11583	11645	62	29.00	0.468	0.190	0.466	0.126	220

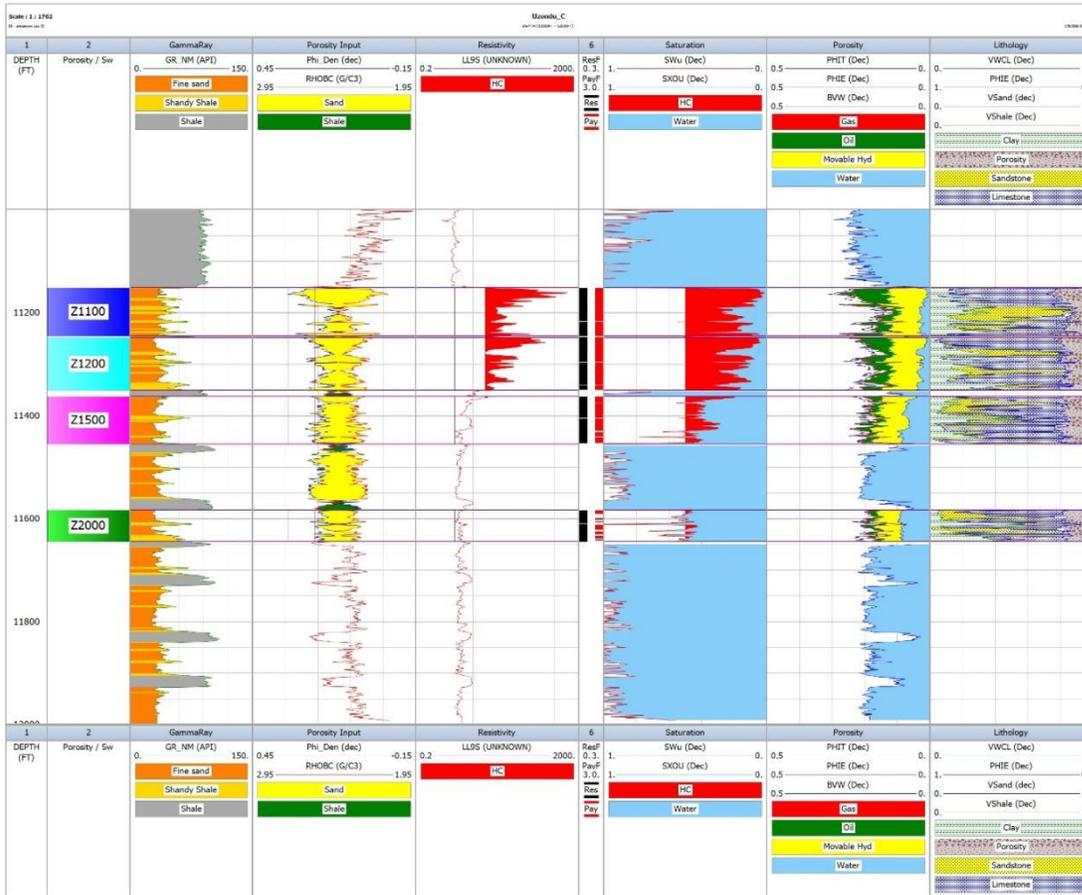


Figure 4: Petrophysical Result for *Uzondu_C*

Petrophysical Characteristics of *Uzondu_D*

The petrophysical evaluation of *Uzondu_D* (Figure 5; Table 4) indicates an absence of effective reservoir intervals within the studied depth range. All identified zones exhibit zero net thickness, implying dominance of shale or non-reservoir lithologies.

This interpretation is supported by high gamma-ray responses, low resistivity, and poor porosity development observed in the log suite. Consequently, permeability was assigned a value of 0 mD, and *Uzondu_D* is interpreted as a non-reservoir or off-axis well, possibly located in a shale-prone depositional environment or outside the main sand fairway.

Table 4: Petrophysical Parameters for *Uzondu_D*

Zone Name	Top (ft)	Bottom (ft)	Gross (ft)	Net (ft)	N/G	Av Phi	Av Sw	Av Vsh	Perm (mD)
Z1100	11172	11250	78	0	0	---	---	---	---
Z1200	11250	11408	158	0	0	---	---	---	---
Z1500	11408	11485	77	0	0	---	---	---	---
Z1700	11486	11535	49	0	0	---	---	---	---

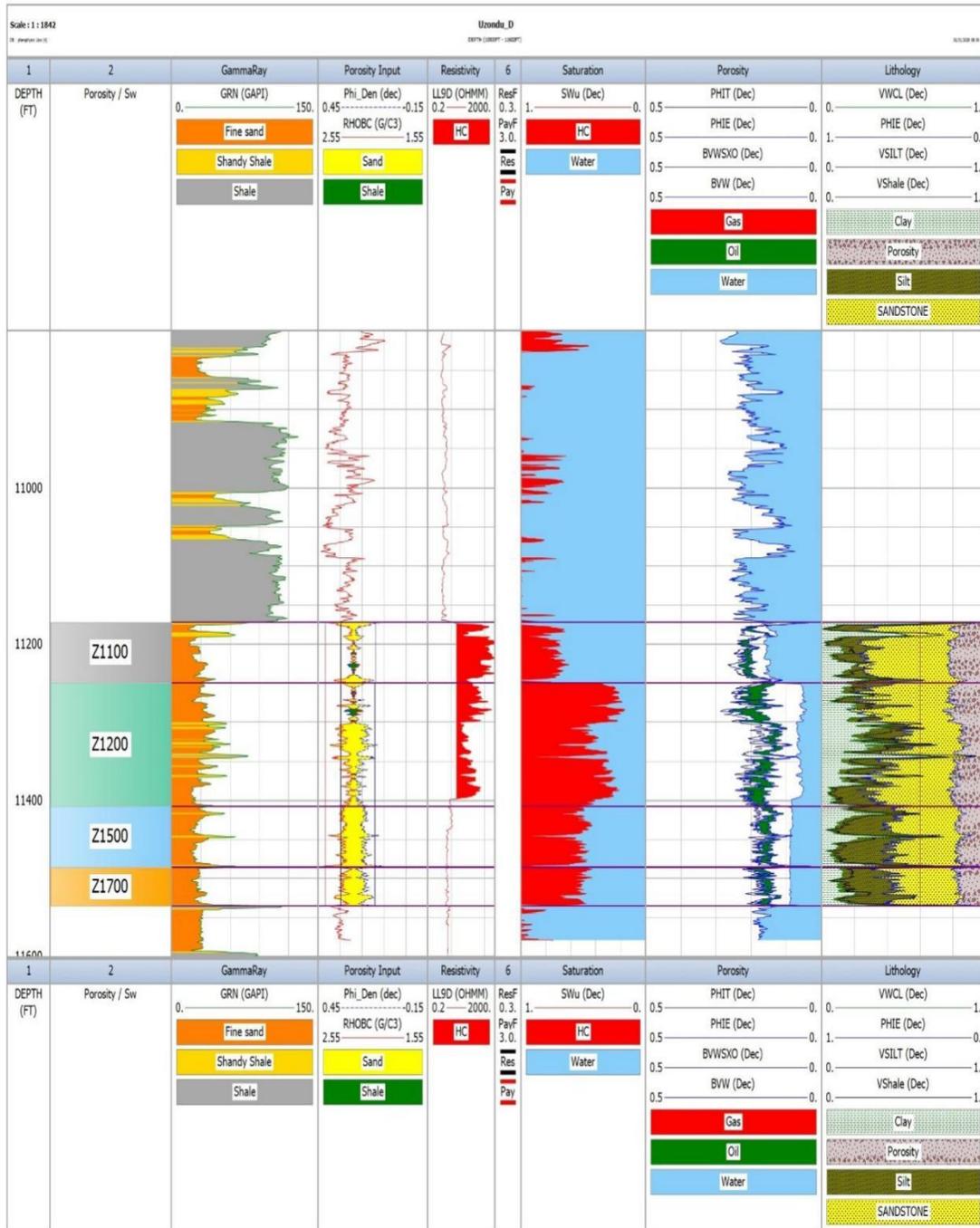


Figure 5: Petrophysical Result for *Uzundu_D*

Petrophysical Characteristics of Uzundu_E

Uzundu_E (Figure 6; Table 5) exhibits high gross thickness but very low net pay, indicating extensive shale dominance with thin sand streaks. Net-to-gross ratios are generally low (≤ 0.2 in most zones), and shale volume is extremely high (V_{sh} often > 0.7). Although porosity values appear moderate (0.134–0.210), the very high water saturation (S_w up to 0.87) and poor permeability (7–55 mD) indicate that these intervals are largely water-bearing and hydraulically

ineffective. Zones Z1500 and Z1700 contain no net reservoir and are classified as non-reservoir units. Overall, *Uzundu_E* represents a marginal to non-productive sector of the field.

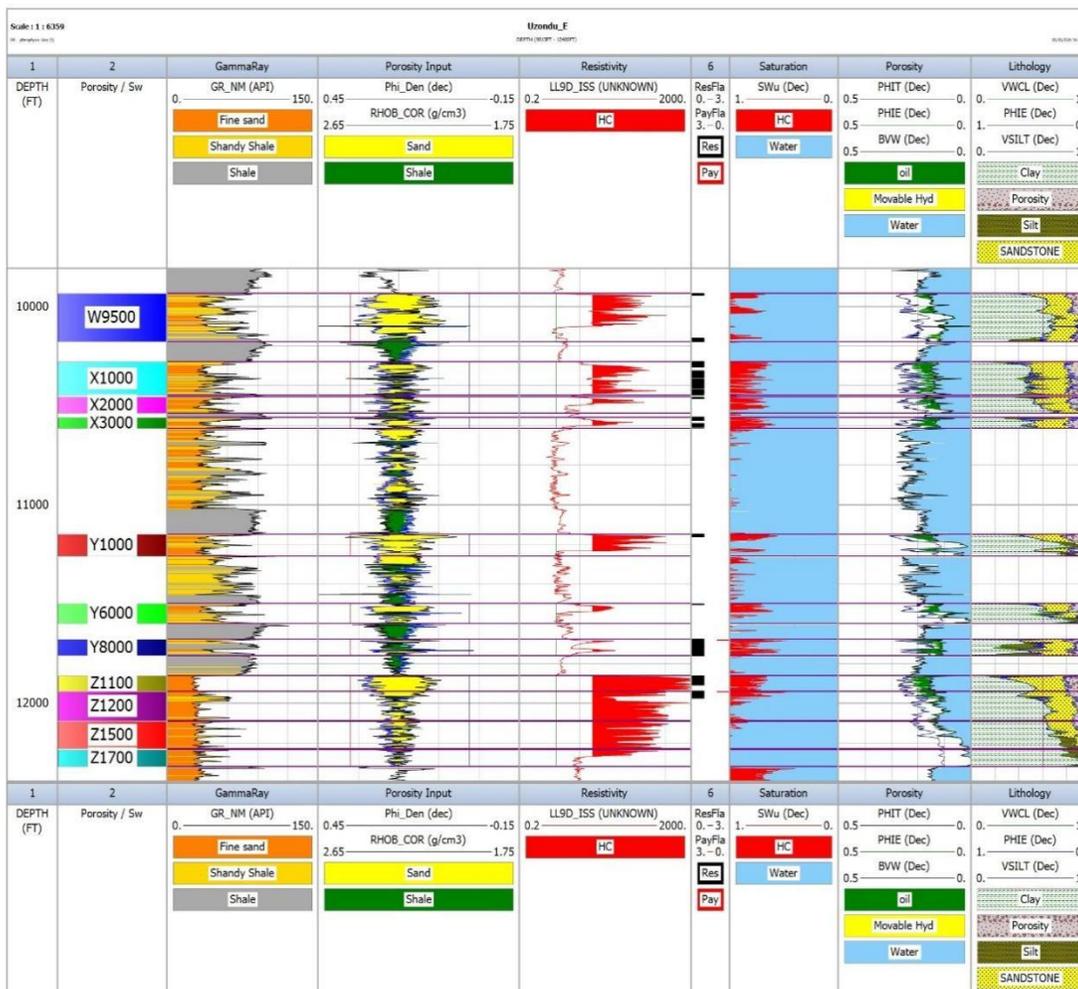


Figure 6: Petrophysical parameters for *Uzundu_E*

Table 5: Petrophysical parameters for *Uzundu_E*

Zone Name	Top (ft)	Bottom (ft)	Gross (ft)	Net (ft)	N/G	Av Phi	Av Sw	Av Vsh	Perm (mD)
W9500	9936	10180	244	27.50	0.113	0.144	0.863	0.381	12
X1000	10279	10449	170	133.00	0.782	0.167	0.808	0.440	18
X2000	10458	10540	82	6.25	0.076	0.136	0.873	0.427	8
X3000	10560	10616	56	32.75	0.585	0.167	0.746	0.419	20
Y1000	11149	11260	111	13.75	0.124	0.210	0.635	0.398	45
Y6000	11500	11600	100	5.25	0.052	0.134	0.818	0.381	7
Y8000	11680	11760	80	71.50	0.894	0.148	0.751	0.329	25
Z1100	11861	11942	81	52.00	0.642	0.206	0.724	0.361	55
Z1200	11942	12091	149	30.75	0.206	0.173	0.727	0.437	18
Z1500	12093	12230	137	0.00	0.000	---	---	---	0

Z1700	12235	12320	85	0.00	0.000	---	---	---	0
-------	-------	-------	----	------	-------	-----	-----	-----	---

Lateral Reservoir Continuity and Field-Scale Implications

The reservoir correlation panel (Figure 7) demonstrates that the reservoirs units, Zone C and Zone E (i.e X and Z series) are laterally continuous between *Uzundu_A* and *Uzundu_B*, confirming a shared depositional framework, likely associated with stacked channel and mouth-bar sand bodies. The Zones B-E (i.e W, X Y, Z series) reservoir units are also laterally continuous between *Uzundu_A* and *Uzundu_E* but does not share the same depositional framework like in *Uzundu_A* and *Uzundu_B* because *Uzundu_E* has extensive shale dominance with thin sand streaks. Reservoir quality deteriorates toward *Uzundu_C* and *Uzundu_E*, while *Uzundu_D* marks a complete transition into non-reservoir facies. Zone E reservoir units (Z-series) was the only reservoir laterally continuous in all the five wells while Zone A reservoir unit (W1000) was only present in *Uzundu_A*. Shale volume was identified as a key secondary control on reservoir quality through its direct impact on porosity and net-to-gross. Increasing clay content leads to pore-filling and pore-lining effects that reduce effective pore space while elevated shale content lowers net-to-gross ratios by increasing the proportion of non-reservoir material within the gross interval. The was the reason why *Uzundu_B* has better reservoir quality that *Uzundu_E* which has more reservoir series present.

This lateral variation reflects facies heterogeneity typical of Niger Delta depositional systems, where high-quality channel sands grade laterally into shaly floodplain or distal delta-front deposits. The integration of petrophysical results across wells highlights a core productive zone around *Uzundu_A* and *Uzundu_B*, with diminishing reservoir potential toward the field margins.

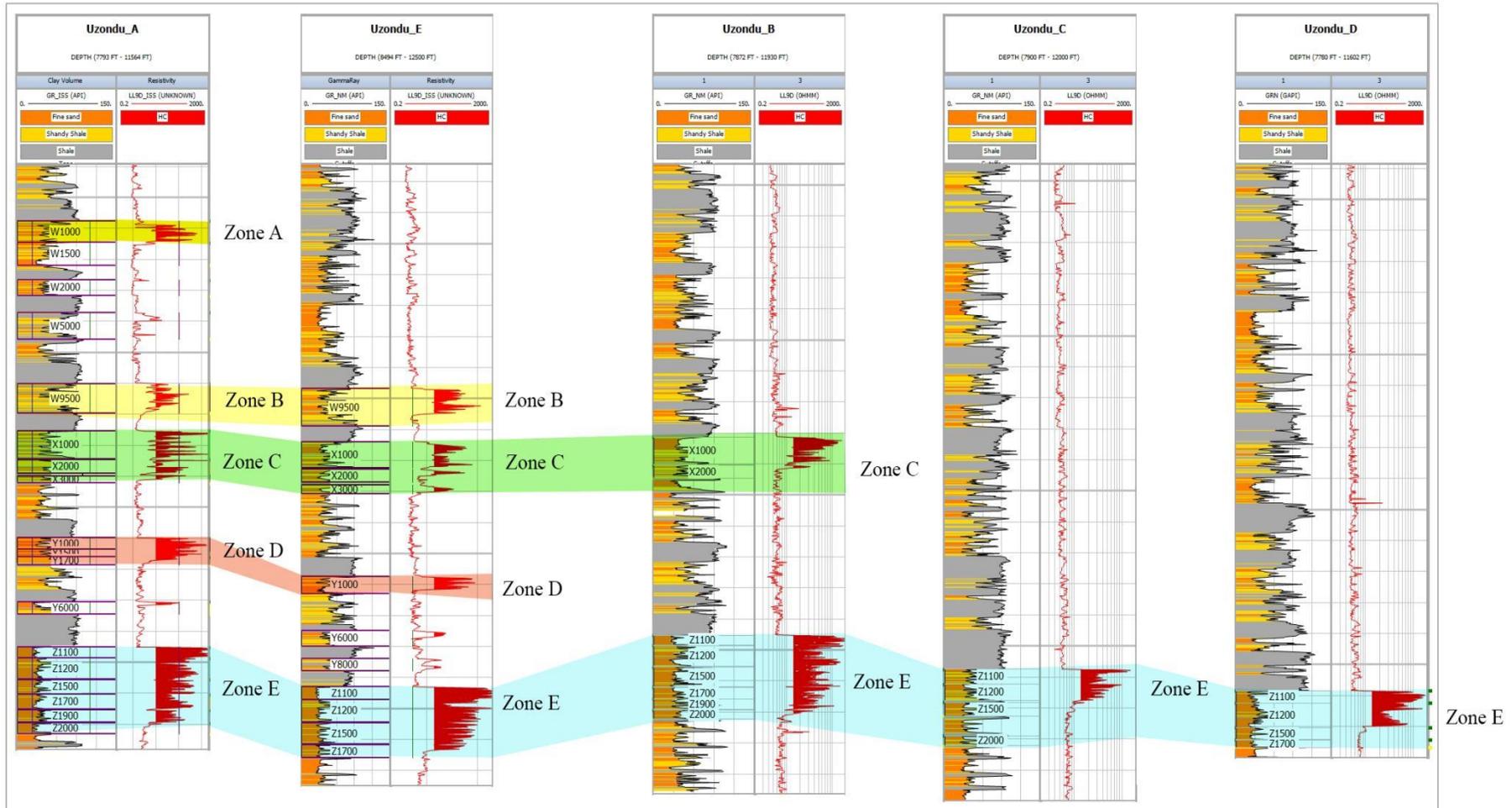


Figure 7: The Lateral Extent of the Reservoir Across the Field

B. Geological Controls on Reservoir Quality in the Uzondu Field

Depositional Facies Control on Petrophysical Properties

Reservoir quality variations in the *Uzondu* Field are fundamentally linked to depositional facies architecture within the paralic succession of the Agbada Formation. The identified reservoir intervals exhibit characteristic log motifs consistent with channel-fill, mouth bar, and floodplain depositional environments typical of Niger Delta deltaic systems (Weber and Daukoru, 1975; Doust and Omatsola, 1990). Channel sand bodies are characterized by blocky to fining-upward gamma ray motifs, sharp basal contacts, and relatively low shale volume ($V_{sh} < 0.25$) as was observed in *Uzondu_A* and *Uzondu_B*. These intervals display the highest effective porosity (Φ_e) and lowest water saturation (S_w), indicating superior reservoir quality. The enhanced petrophysical properties are attributed to higher depositional energy conditions that promoted better grain sorting, reduced clay matrix content, and improved primary intergranular porosity preservation.

Mouth bar deposits exhibit coarsening-upward log motifs with moderate shale intercalations as was observed in *Uzondu_C*. Petrophysical parameters within these intervals show intermediate reservoir quality (moderate Φ_e and NTG), reflecting fluctuating depositional energy and episodic clay drapes. The presence of thin shale laminae contributes to anisotropy and may locally reduce vertical permeability despite acceptable porosity values. Floodplain and over bank deposits are dominated by high gamma ray signatures and elevated shale volume ($V_{sh} > 0.40$) as was observed in *Uzondu_E*, with correspondingly low effective porosity and high-water saturation. These intervals act predominantly as intra-reservoir baffles or seals. The poorer reservoir quality in these facies is attributed to fine-grained sedimentation, high clay content, and intense mechanical compaction. The systematic decrease in reservoir quality from channel sand to mouth bar to floodplain facies demonstrates that depositional energy regime is a primary control on petrophysical heterogeneity in the *Uzondu* Field. This facies-controlled variability explains the lateral and vertical fluctuations observed in porosity, shale volume, and net-to-gross ratio across the five (5) wells.

Structural Controls on Reservoir Distribution and Quality

The *Uzondu* Field is structurally influenced by syn-depositional growth faulting, a dominant structural style in the Niger Delta Basin (Doust and Omatsola, 1990). Fault proximity plays a significant role in controlling both sediment accommodation and reservoir preservation. Reservoir intervals located on structural highs exhibit relatively lower water saturation and improved hydrocarbon accumulation efficiency. Structural crests favor hydrocarbon migration and entrapment, resulting in thicker net pay intervals and higher hydrocarbon saturation. Conversely, wells positioned downthrown relative to major growth faults display increased shale smear potential and localized reductions in net-to-gross ratio. Shale drag along fault planes may introduce vertical compartmentalization, influencing fluid distribution and pressure communication. Additionally, enhanced burial on downthrown blocks may accelerate compaction, leading to slight porosity reduction relative to upthrown counterparts at equivalent stratigraphic levels. The spatial variation in net pay thickness and fluid saturation therefore reflects combined structural and stratigraphic controls.

Quantitative Compaction Trends with Depth

Compaction exerts a predictable control on porosity reduction in clastic sedimentary basins. In deltaic sandstones of the Niger Delta, porosity generally decreases exponentially with depth due to mechanical compaction and quartz cementation (Ehrenberg and Nadeau, 2005). In the *Uzundu* Field, calculated effective porosity demonstrates a negative correlation with depth, consistent with normal compaction trends. Quantitatively, porosity reduction follows an exponential decay relationship of the form:

$$\phi = \phi_0 e^{-cz} \quad (5)$$

where ϕ = porosity at depth z , ϕ_0 = initial depositional porosity, c = compaction coefficient and z = burial depth. Observed porosity values decrease progressively with increasing burial depth, with shallow reservoir units exhibiting higher porosity compared to deeper stratigraphic intervals. The compaction gradient derived from the well dataset indicates a systematic reduction in effective porosity per unit depth, suggesting mechanical compaction as the dominant diagenetic process within the evaluated depth range. However, deviations from the normal compaction trend are locally observed in high-quality channel sands, indicating that depositional texture and grain framework exert secondary controls capable of partially mitigating compaction effects. This highlights the interplay between depositional facies and burial diagenesis in controlling ultimate reservoir quality. The reservoir quality of the *Uzundu* Field is governed by three interrelated geological factors:

- (a). Depositional facies architecture which places primary control on porosity, shale volume, and NTG.
- (b). Structural framework which influences hydrocarbon trapping efficiency, fault-related compartmentalization, and accommodation space.
- (c). Burial compaction trends which control systematic porosity reduction with depth.

The integration of these geological controls provides a more robust interpretation of the observed petrophysical heterogeneity and significantly strengthens the reservoir characterization framework for the field.

5. CONCLUSION

Reservoir quality assessment using petrophysical analysis in *Uzundu* Field, Niger Delta Basin was carried out by careful analysis and interpretation of its well logs data. The results of identified reservoir zones (W, X, Y, and Z series) in *Uzundu_A* exhibit high-quality reservoirs suggesting hydrocarbon-bearing. *Uzundu_B* demonstrates good to very good reservoir quality and the quality of the reservoirs deteriorates toward *Uzundu_C* and *Uzundu_E*, while *Uzundu_D* marks a complete transition into non-reservoir facies.

ACKNOWLEDGMENTS: The authors are grateful to Shell Petroleum Development Companies in Nigeria (SPDCN) for provision of the data that was used for this research work.

REFERENCES

- [1] Abdolla, E. (2010). "Evaluation of Petrophysical Properties of an Oil Field and their effects on production after gas Injection," *1st International Applied Geological Congress*, Department of Geology, Islamic Azad University – Mashad Branch, Iran, pp. 26-28, 2010.
- [2] Archie, GE (1942). The electrical resistivity log as an aid in determining some reservoir characteristics. *J. Petrol. Technol.* 5: 54-62
- [3] Doust, H; Omatsola, E (1990). Niger Delta: In Edwards, JD; Santogrossi, PA (ed) divergent/passive margin basins: Am. Assoc. Petrol. Geol. Bull Memoir 48:201-328
- [4] Ehrenberg, S. N. and Nadeau, P. H. (2005). Sandstone vs. carbonate petroleum reservoirs: A global perspective on porosity-depth and porosity-permeability relationships. *AAPG Bulletin*, 89(4), 435–445.
- [5] Galloway, W. (1989). Genetic stratigraphic sequences in basin analysis, architecture and genesis of floodingsurfaces bounded by depositional units. *American Association of Petroleum Geologists, Bulletin* 73, 125-142.
- [6] Inyang, N. J., Okwueze, E. E., and Agbasi, O. E. (2015). Detection of Gas Sands in the Niger Delta by Estimation of Poisson's Dampening-Factor (PDF) Using Wireline Log Data. *International Journal of Advanced Geosciences*, 5, 46-51. doi:10.5923/j.geo.20150501.06.
- [7] Kumar, M., Dasgupta, R., Singha, D.K., and Singh, N.P., (2018). Petrophysical evaluation of well log data and rock physics modeling for characterization of Eocene reservoir in Chandmari oil field of Assam-Arakan basin, India. *Journal of Petroleum Exploration and Production Technology* 8 (2), 323e340. <https://doi.org/10.1007/s13202-017-0373-8>.
- [8] Okoli, E. A., Agbasi, O. E., Onyekuru, S., and Sunday, E. E. (2018). Cross plot analysis of rock properties from well log data for gas detection in Soku field, coastal swamp depobelt, Niger Delta Basin. *Journal of Geoscience, Engineering, Environment and Technology, Vol 03 No 04*, 180-186. <http://journal.uir.ac.id/index.php/JGEET>
- [9] Omoja, U. C. and Obiekezie, T. N. (2021). Evaluation of Petrophysical Parameters of Reservoir Sand Wells in Uzot-Field, Onshore Niger Delta Basin, Nigeria. *J. Appl. Sci. Environ. Manage.* Vol. 25 (2) 157-171 February 2021
- [10] Saadu, Y.K., and Nwankwo, C.N., (2018). Petrophysical evaluation and volumetric estimation within Central swamp depobelt, Niger Delta, using 3-D seismic and well logs. *Egyptian Journal of Petroleum* 27 (4), 531e539. <https://doi.org/10.1016/j.>
- [11] Stacher, P (1995). Present understanding of the Niger Delta hydrocarbon habitat, in Oti, MN; Postma, G (ed) *Geology of Deltas*: Rotterdam, A.A. Balkema., 257-267.
- [12] Timur, A (1968). An investigation of permeability, porosity and residual water saturation relationships for sandstone reservoirs: *The Log Analyst*, 9(4):8-17.
- [13] Tuttle, MLW; Charpentier, RR; and Brownfield, ME (1999). The Niger delta petroleum system: Niger delta province, Nigeria, Cameroon, and Equatorial Guinea, Africa: *USGS Open-file report 99-50-H*: 1-64.
- [14] Ubong, E. E., Akaninyene, O. A., and Agbasi, E. O. (2017). Evaluation of Reservoirs Petrophysical Parameters, Niger Delta, Nigeria. *International Journal of Advanced Geosciences*, 5, 19-25. doi: 10.14419/ijag.v5i1.7456.

- [15] Uguru, CI; Onyeagoro, OU; and Sikiru, IO (2002). Permeability modeling for reservoirs in the Niger Delta based on geological descriptions and core data. *SIPM Review Report*. 4 – 98.
- [16] Weber, K. J., and Daukoru, E. M. (1975). Petroleum Geology of the Niger Delta. *Jour. Min. Geol.*, 12, 9-12
- [17] Whiteman, A. J. (1982). *Nigeria: Its Petroleum Geology, Resources and Potential*, Graham and Trotman, London, 1982.