

Exploring Reservoir Potential of the "X Field" Offshore, Niger Delta Basin: An Emphasis on Lithofacies, Depositional Environments, and Petrophysical Characteristics

Agbasi Ebuka Okechukwu ^{1,2,a,*}, Nwokoma Uzoma Esomchi ^{1,b},
Azunna Enyinnaya Daniel ^{1,c}, and Ugwu Joshua Udoka ^{1,d}

¹ Department of Physics, College of Physical Science, Michael Okpara University of Agriculture
Umudike, P.M.B. 7267, Nigeria

² Geophysics Unit, Okna Geoservices Nigeria Limited
21 Main School Road, Off Hospital Road Eket, Akwa Ibom, Nigeria

e-mail: ^a agbasi.okechukwu@gmail.com, ^b nwokoma.esomchi@mouau.edu.ng, ^c azudanenyi@gmail.com,
and ^d ugwu.joshuaudoka@mouau.edu.ng

* Corresponding Author

Received: 19 March 2023; Revised: 14 May 2023; Accepted: 31 May 2023

Abstract

The geological circumstances under which sediments are built throughout time are referred to as depositional environments. The features of the sediment, such as its texture, composition, and permeability, are influenced by these depositional environments, and these qualities ultimately define the reservoir quality. This study focuses on identifying reservoirs in the western offshore region of Nigeria's Niger Delta Basin and evaluating their properties, such as lithofacies, distribution, and petrophysical characteristics like porosity and permeability, using well log analysis. By utilizing relevant and easily accessible well log data, the depositional environment and quality of the reservoir were evaluated. The data analysis involved examining gamma-ray log patterns, spontaneous potential, deep resistivity, neutron, and density. The thickness of the reservoirs varies between 15 and 440 meters, with thicker reservoirs likely being composite structures formed from layered channels. Sands deposited in high-energy settings have higher levels of porosity and permeability. Sands C and D are the most porous and permeable sand units in the field, while the remaining sands have medium permeability. Hydrocarbons are present in sands B, C, D, and E in varying fluid types and column diameters. The reservoir sands C, D, and E have high hydrocarbon saturation and low water saturation, indicating that more oil than water will be produced. On the other hand, irreducible sand B suggests that more water than oil will be produced. Reservoir sands B, C, and D contain only water and oil. This information can aid in locating production platforms and optimizing hydrocarbon recovery, as well as improving reservoir performance estimates. The geological and petrophysical data collected in this study can also guide the analysis of other fields similar to the "X Field" in Nigeria's Niger Delta offshore region.

Keywords: Deposition; Permeability; Porosity; Reservoir

How to cite: Okechukwu AE, et al. Exploring Reservoir Potential of the "X Field" Offshore, Niger Delta Basin: An Emphasis on Lithofacies, Depositional Environments, and Petrophysical Characteristics. *Jurnal Penelitian Fisika dan Aplikasinya (JPFA)*. 2023; 13(1): 38-50.

© 2023 *Jurnal Penelitian Fisika dan Aplikasinya (JPFA)*. This work is licensed under [CC BY-NC 4.0](https://creativecommons.org/licenses/by-nc/4.0/)

INTRODUCTION

The Niger Delta is an area in Nigeria known for its significant reserves of hydrocarbons, which include both oil and natural gas [1]. These hydrocarbons are found in microscopic pore spaces or open cracks in reservoir rocks. The Niger Delta's most abundant type of reservoir rock is sandstone, which is capable of storing fluids such as water, gas, or oil. Therefore, the primary aim of oil and gas exploration in the Niger Delta is to locate reservoirs that contain hydrocarbons. The Niger Delta reservoir rocks are sandstone, according to numerous geological investigations, including those by Onyekuru et al. [2], Nwokoma et al. [3], Inyang et al. [4], Reijers [5], Doust and Omatsola [6], Weber and Daukoru [7], and Short and Stauble [8].

Depositional environments refer to the geological conditions in which sediments accumulate over time [9]. In the case of the Niger Delta, sedimentary deposits were formed in various environments, such as fluvial channels, estuaries, deltas, and marine environments. These depositional environments influence the characteristics of the sediment, including its texture, composition, and permeability, which ultimately determine its reservoir quality [10]. Reservoir quality refers to a sedimentary deposit's ability to hold and transfer fluids, particularly hydrocarbons. The quality of a sediment reservoir is determined by factors such as porosity, permeability, and fluid saturation. In particular, the depositional environment and local geological history affect the reservoir quality of sediment in the Niger Delta Field.

Understanding the depositional environment and quality of sedimentary reservoirs is crucial for the successful exploration and extraction of hydrocarbons in the Niger Delta [2]. This knowledge can help identify areas with high potential for hydrocarbon accumulation, optimize drilling and completion practices, and improve overall hydrocarbon recovery. Depending on the depositional environment, different sand body trends, forms, sizes, and heterogeneities exist [11]. Reconstructing depositional settings in clastic successions is crucial for defining and predicting the distribution of reservoir quality because various processes in depositional environments affect the physical properties of clastic reservoir rocks [12]. Therefore, it is important to understand the processes that occur in depositional settings to predict the physical characteristics of reservoir rocks. By thoroughly describing and analyzing wireline logs of reservoir depositional settings [13], it is possible to better comprehend reservoir features and, consequently, their quality for the optimum utilization of embedded resources, which is determined by the porosity and permeability of a reservoir. The distribution of petrophysical properties and trends found during formation evaluation can be used to derive this.

Scientists are currently studying the "X Field", located offshore in Nigeria's Niger Delta and the Gulf of Guinea, in order to gain a better understanding of the geological factors that contribute to the formation and preservation of hydrocarbon reservoirs [1-5]. By analyzing the depositional settings and reservoir quality in this area, researchers aim to improve hydrocarbon recovery and production, identify regions with high hydrocarbon potential, and guide future exploration efforts. Understanding the geology and reservoir features in different oil and gas fields throughout the world has been the main focus of prior studies in the field of hydrocarbon

exploration and production. Studies have looked at depositional settings, lithofacies, and reservoir characteristics to enhance reservoir performance predictions and improve hydrocarbon recovery methods.

This research is unusual in that it specifically focuses on the depositional environment and sediment reservoir quality in the “X Field” of the Niger Delta, which has not been substantially investigated. The intricate and dynamic character of the geological history of the “X Field” and the Niger Delta, which was formed over millions of years under various climatic circumstances, displays a distinctive feature. This study closes a significant information gap by exploring the “X Field” and examining its lithofacies, sub-lithofacies, and reservoir features. It offers insightful information on the “X Field” geological past, depositional environment, and sediment reservoir quality, which may greatly improve reservoir performance estimates and boost hydrocarbon recovery. This study can contribute to a more comprehensive understanding of the geology of the Niger Delta and improve the ability to identify and exploit hydrocarbon resources in the region by investigating the depositional environments and reservoir quality in the “X Field”.

METHOD

Study Area Geology

Nigerian Agip Exploration Ltd. owns the "X Field," which is located offshore in Nigeria's Niger Delta and the Gulf of Guinea. Figure 1 illustrates the positions of the well sites within the "X Field".

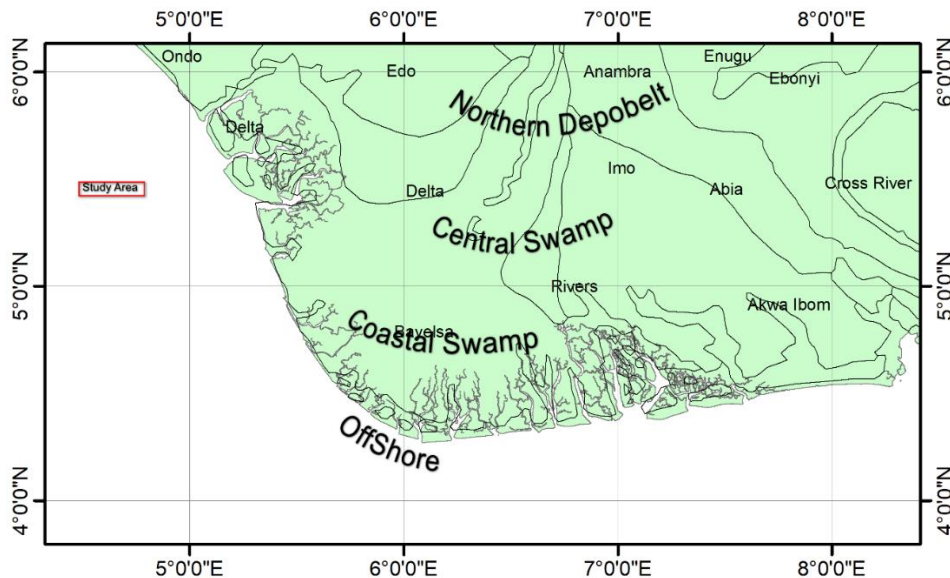


Figure 1. Niger Delta map (in the red location of “X Field”).

Weber and Daukoro [7] have identified three main depositional cycles in Nigeria's coastal sedimentary basins. The first cycle began during the Albian period with a sea invasion and ended in the Santonian period. The second cycle began during the Eocene era with the emergence of the Niger Delta and is still ongoing. However, in the late Quaternary, uplift and erosion frequently interrupted sedimentation, resulting in submerged canyons formed by cycles of channel cutting and filling [12, 14].

Short and Stauble [8] and Doust and Omatsola [6] both found a sequence of deltaic and marine clastic in the Niger Delta that regresses and consists of three key lithofacies. The Akata Formation's coastal shale is part of a paralic sequence that also includes interbedded sand and shale from the Agbada Formation and continental sand from the Benin Formation. Six main depobelts were identified in the Niger Delta Basin by Doust and Omatsola [6], including Coastal Swamp I and II, Central Swamp, Great Ughelli, and the Northern Delta.

Poston et al. [15] utilized a technique that involved combining core data with well log interpretation to determine the geographical variability of porosity and permeability in specific reservoir intervals. Asquith and Krygowski [16], as well as Enikanselu and Ojo. [17], have classified sediments into five lithofacies, which include coarse-grained sand, medium-grained sand, fine-grained sand, very fine-grained shale, and silty shale. A comprehension of the Niger Delta's lithofacies and reservoir intervals can aid in identifying regions with high hydrocarbon potential and enhancing hydrocarbon recovery and production

Data Collection

This study utilized data from oil fields located in the Niger Delta Basin of Nigeria. The dataset consisted of wireline well logs collected from five different wells, which contained measurements for various petrophysical properties, such as density, deep resistivity, neutron, spontaneous potential, and gamma rays. These data were analyzed to evaluate the petrophysical characteristics and sedimentological setting of the field.

Data from six wells, including five wells (X1, X2, X3, X4, and X5) and an analogue well (TTK 7), were used in this study. The well logs contained gamma ray, spontaneous potential, resistivity, and neutron density logs. The gamma ray logs were aligned at the same depths for ease of correlation, and the True Vertical Depth Subsea (TVDSS) was calculated based on depth information.

Data Analysis

The characteristics of the reservoir were evaluated by conducting a quantitative analysis of various petrophysical variables such as shale volume, porosity, water saturation, permeability, and bulk water volume. These parameters are further explained below to provide a better understanding

Shale Volume / Gamma Ray Index

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (1)$$

The gamma ray index (I_{GR}) is calculated using the gamma ray production log (GR_{log}), the minimum gamma ray (GR_{min}), and the maximum gamma ray (GR_{max}).

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

To initiate the analysis, the gamma-ray log was utilized to compute the gamma-ray index I_{GR} . Additionally, the quantity of shale present in Tertiary rocks was estimated using Larionov's [18] formula, where V_{sh} stands for shale volume.

Porosity

Two stages were involved in estimating the porosity. In the first stage, the Wyllie equation was applied to determine the density-derived porosity (ϕ_D). In the second stage, the neutron-

derived porosity (ϕ_N) and density-determined porosity (ϕ_{ND}) were combined. Equation 3 is the Wyllie equation for density-derived porosity:

$$\phi_D = \frac{(\rho_{max} - \rho_b)}{(\rho_{max} - \rho_{fluid})} \quad (3)$$

The symbol ρ_{max} represents the maximum density of the rock matrix, and ρ_{fluid} denotes either water or oil, which have a density of 2.65 g/cc or 1.1 g/cc, respectively. to determine the porosity of the neutron density, the following method was used:

$$\phi_{ND} = \frac{(\phi_N + \phi_D)}{2} \text{ for oil and water column} \quad (4)$$

$$\phi_{ND} = \frac{2(\phi_N + \phi_D)}{3} \text{ for gas bearing zones} \quad (5)$$

The density of the rock in the formation is determined by the log, while the density of the fluid occupying the pore spaces is determined by the fluid's own density, which is 0.74 grams per cubic centimeter for gas and 0.9 grams per cubic centimeter for oil [19].

Permeability

Permeability refers to the degree to which a fluid (such as gas, oil, or water) can flow through the interconnected pores of a reservoir rock. It is a critical factor in determining how rapidly a reservoir will deplete.

$$K = 0.136 \left(\frac{4.4}{S_{wirr}^2} \right) \quad (6)$$

Where K is permeability, S_{wirr} is irreducible water saturation.

Water and Hydrocarbon Saturation

The saturation of hydrocarbons and water are linked, and the equation developed by Archie was utilized to ascertain the resistivity of the formation water. The equation relates the resistivity of the formation water (R_w) to the resistivity of the formation at full water saturation (R_o) and the formation factor (F).

The equation formulated by Archie [20] was applied to calculate the water saturation of the uninvaded zone:

$$S_w^2 = \frac{F \times R_w}{R_t} \quad (7)$$

$$F = \frac{R_o}{R_w} \quad (8)$$

The equation involves variables such as S_w , which represents water saturation in the uninvaded zone; R_o , which represents the formation's resistivity at 100% water saturation; and R_t , which represents the actual resistivity of the formation.

$$S_w = \sqrt[n]{\frac{a \times R_w}{R_t \times \phi^m}} \quad (9)$$

The equation for calculating hydrocarbon saturation involves several variables, such as porosity (ϕ), saturation exponent (usually 2.0, denoted by n), cementation (m), and tortuosity (a). Formation water resistivity (R_w), real formation resistivity (R_t), determined using the deep induction resistivity log, and water saturation (S_w) are also included in the equation. To calculate hydrocarbon saturation, the proportion of water saturation is subtracted from 100.

Estimating Effective Porosity

The porosity of the linked pore spaces is represented by ϕ_{eff} . It is based on the reservoir's lack of shale. This is generally based on adjusting total porosity with an expected shale volume.

$$\phi_{eff} = \phi_{total} - (\phi_{sh} \times V_{sh}) \quad (10)$$

where ϕ_{eff} is effective porosity, ϕ_{total} is total porosity, ϕ_{sh} is log reading in a shale zone, and V_{sh} is the volume of shale.

It can also be calculated using the following relationship:

$$\phi_{eff} = (1 - V_{sh}) \times \phi_{ND} \quad (11)$$

where ϕ_{ND} is neutron-density porosity.

Bulk Volume Water (BVW)

Adepelumi et al. [21] explained that the BVW is the outcome of correcting porosity and water saturation in shale. The homogeneity of a zone and irreducible water saturation can be determined by the coherence of BVW values at various depths within a formation. Thus, hydrocarbon extraction from such areas must not involve water [22]. The BVW is computed based on the uninvasion zone's water saturation and porosity, corrected for shale.

The BVW was calculated as the product of the uninvasion zone's water saturation (S_w) and porosity (ϕ_{ND}). Thus,

$$BVW = S_w \times \phi_{ND} \quad (12)$$

where ϕ_{ND} is neutron-density porosity.

Fluid Type

Asquith and Krygowski [16] and Ojo et al. [22] stated that by correlating neutron and density logs, it is feasible to distinguish among various types of fluids occupying pore spaces in formations. The increase in the value of the density log indicates the presence of hydrocarbons, which creates a crossover point. The distance between the two curves, known as the crossover, is greater in the presence of gas than it is in the presence of oil....

Formation Evaluation

Akpabio et al. [23] utilized the gamma ray log to identify the lithology of the wells, with the shale serving as a reference point for the rightward deflection in the log signature, while the sandstone primarily caused the leftward deflection. The resistivity log's leftward deflections were linked with low resistance or high conductivity, indicating the presence of salt deposits. Agbasi et al. [24] and Asquith and Krygowski [16] employed various logs, including gamma ray, spontaneous potential, resistivity, and neutron density, to locate hydrocarbon-bearing reservoir sand formations. While wireline logs were used to compute the petrophysical properties of reservoir sands, gamma ray and resistivity logs were used to evaluate lithofacies.

RESULTS AND DISCUSSION

Lithofacies

Gamma ray and core plug descriptions were utilized to determine lithologies, specifically sand and shale, as shown in Figure 2. The characterization and evaluation of conventional core samples is the first step in clastic reservoir facies analysis, as noted by Inyang et al. [25]. One crucial impact of core classification is the division of cores into lithofacies, which is essential for studying depositional environments. Lithofacies are subsets of sedimentary basins based on

lithology, size distribution, sedimentary construction, stratification, and their connection to depositional processes. Lithofacies associations, which are groups of linked lithofacies, are also crucial units for depositional analysis.

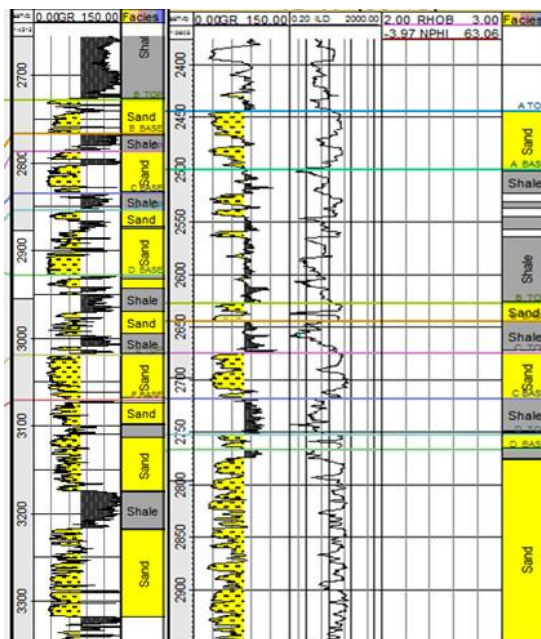


Figure 2. Typical well sections illustrating the lithological units in the "X Field."

Inferred Environment of Deposition

The features of sandstone, particle size, spontaneous potential, and gamma ray log patterns can be used to predict the depositional environment [26-30]. Based on these patterns, potential deposits near the delta complex's outer reaches include deep-sea channel sands, low-stand sand bodies, and proximal turbidites [10, 29]. The predicted habitat for shale ranges from fluvio-deltaic to deltaic front to prodeltaic to shelf margin to marine. The gamma ray logs of various reservoir sands show different log forms, indicating deposition in different environments, such as fluvial or tidal flood plains, deltaic distributaries, deltaic fronts, shorefaces, tidal flats, tidal channels, and proximate offshore areas [26, 27]. Differences in well log patterns may indicate lateral variations in rock character, which can be detected in connection with the section and interpreted with knowledge of the depositional environment from the cored section.

The depositional environment, including factors such as grain size, sorting, cementation, and compaction, controls the porosity and permeability of reservoir sands [10, 31]. Based on gamma ray log patterns and core plug descriptions, the depositional environment of the reservoir sands has been identified as ranging from the fluvio-deltaic plain to the shelf margin or slope. Fluvial and fluvio-marine processes are responsible for producing higher-quality reservoirs than marine processes [26, 27, 29]. Sandstone sorting influences the amount of shale in each unit, the depositional environment and processes, and the diversity in porosity and permeability of reservoir sand units.

Well Correlation

The team utilized their knowledge of formation geology and lithology to create well log correlations for the "X Field" (illustrated in Figures 3 and 4). The study identified five reservoirs, which were found to be consistently present across the wells and laterally continuous

(reservoirs A, B, C, D, and E). The researchers used gamma-ray signals to establish litho-stratigraphic correlations, which revealed that reservoirs B, C, and D were present in all the wells. Reservoirs A through E were observed in Wells 003 and 004, indicating that they were also laterally persistent.

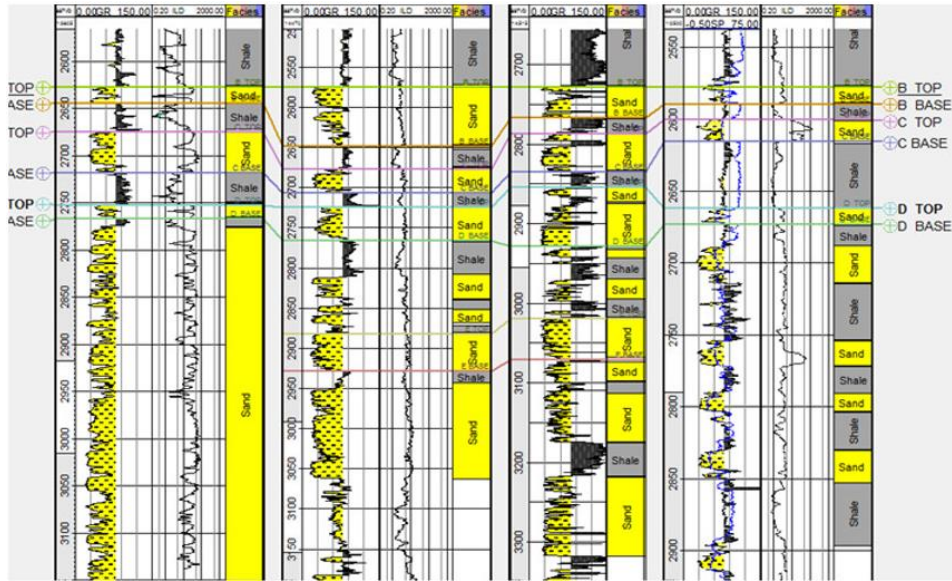


Figure 3. Log correlation profile through X1, X2, X3 and X4 showing the geometry of the field.

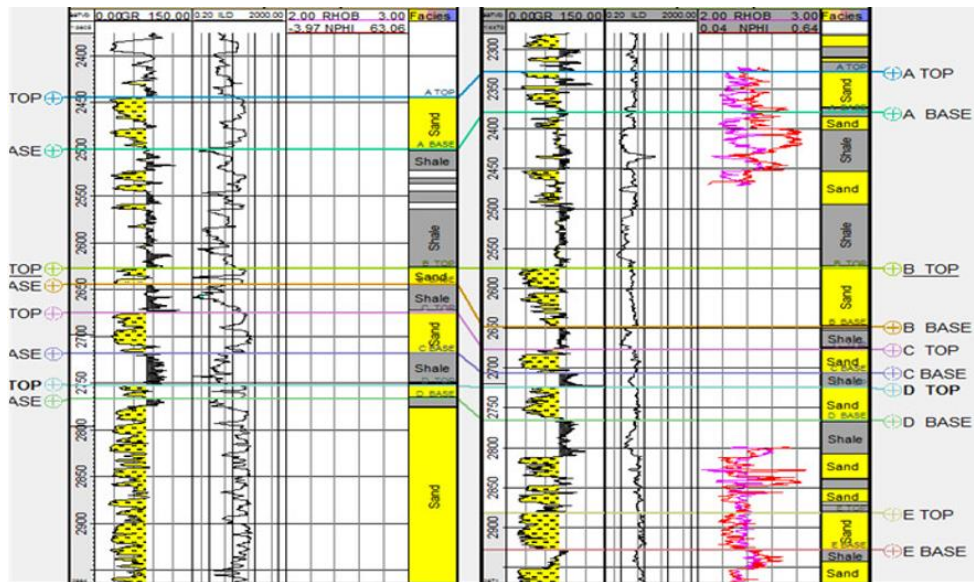


Figure 4. The log correlation across X2 and X3 displays the tops and bases of the five reservoirs.

Reservoir properties in the “X Field”.

Only a small percentage of the area has reservoirs with thicknesses greater than 45 meters, as growth faults have a significant impact on the reservoir's lateral thickness variation. According to Doust and Omatsola [6], the thicker reservoirs are likely composed of stacked channels, possibly in the form of composite bodies. The litho units in wells X1, X2, X3, X4 and X5 have a range of top depths between 2180 to 3200 meters, base depths between 2380 and 3370 meters, and a corresponding thickness range of 15 to 440 meters, a range of top, depth and

thickness are similarly reported by some research [1-3, 11-14, 19, 22, 24, 26, 27].

The lateral variation in porosity among different reservoir sand units is attributed to changing environmental conditions. For example, Sand Body A, which had an average porosity of 14.8% across the field and exhibited variable porosities at several wells, had porosities of 16.29% at Well X3, 15.09% at Well X4, and 28.77% at Well X5. Sand B, like Sand A, also displayed varying porosity values at different wells, with an average porosity of 15.42%, 15.14% at Well X1, 18.11% at Well X3, 14.40% at Well X4, and 28.77% at Well X5. Table 1 shows the findings of the field study on the porosity of the sand units.

Table 1. Presents the porosity values for the reservoir sand unit across the entire "X Field".

Litho Units / Porosity (%)	X001	X003	X004	X005	CORE	Quality Evaluation
Sand A	Range	15-20	15-18		10-17	Fair to Good
	Average	16.29	15.09		14.89	
Sand B	Range	13-17	22-31.90	13-15	22-34	Good to Excellent
	Average	15.14	22.5	14.40	28.77	
Sand C	Range	10-23	20-24	19-24	19-32	Good to Very Good
	Average	18.33	21.70	20	26.05	
Sand D	Range		12.22-25.04	14-22	21-26	Good to Very Good
	Average		19.52	16	23.14	
Sand E	Range		13-17		19-37	Fair to Good
	Average		13.32		29.59	

The porosity of the field appears to be largely unaffected by compaction and diagenetic processes, as opposed to the depositional processes and contexts of deposition. The lateral variation in porosity might have been influenced by changes in the depositional environment and the gradual increase in depth due to the movement of the coastline and the shift in deposition towards the south and the sea, similar to the results presented by Olaviwola [26], Friday [27], and Archie [20]. This variation is noticeable in the gamma-ray log patterns, where sands deposited in low-energy environments exhibit a decrease in porosity due to little or no reworking (attributed to the presence of shales, silts, and clays in this environment). On the other hand, sands deposited in high-energy environments, such as the tidal plain and the deltaic front, exhibit higher porosity values due to the effect of powerful waves on reworked sands. This environment also leads to improved sorting and a reduction in the heterolithic nature of the sediment.

Sand C is the most permeable unit in the "X Field", with an average permeability ranging from 9.71 mD to 253.49 mD and a range of 106.63 mD to 130.25 mD. Sand D has the second-highest average permeability, with permeability values of 150.53 mD, 18.06 mD, 21.50 mD, and 68.89 mD at Wells X1, X3, X4, and X5, respectively. These two sandstones also have the highest porosity and permeability in the field. The permeability ratings of reservoir sands A, B, and E are lower than those of the other two sand bodies. Sand A and B have the same permeability values throughout the field. Meanwhile, Sand E has slightly higher permeability values compared to these other two sands. Table 2 presents the permeability values for the five reservoir sands in the study area. Although there is considerable variation both horizontally and vertically, the permeability ratings are generally moderate to good. The high permeability of the reservoir sandstones in the field would allow for rapid movement of water and hydrocarbons.

Table 2. Displays the permeability values (K) for the reservoir sand across the entire "X Field."

Litho Units / Permeability (mD)		X001	X003	X004	X005	CORE	Quality Evaluation
Sand A	Range	1.06-540.58	38-49.90	22.15-185.68			Good
	Average	53.24	43.95	85.6		50.21	
Sand B	Range	6.18-279.92	87.7-221.1				Good
	Average	89.0	103.97	105.1	54.65	80.02	
Sand C	Range	36.98-355.85				9.71-253.49	Good
	Average	170.4	172.0	68.1	53.99	121.68	
Sand D	Range	6.80-127.17	0.62-24.96				Moderate
	Average	61.5	6.80	73.3	53.72	43.95	
Sand E	Range	12.56-180.25					Good
	Average	71.13	75.7	90.8	30.19		

Sands B, C, D, and E all contained hydrocarbons, but the type and quantity of fluids varied between wells. The reservoir sand A at Wells X3 and X4 contained both oil and water. Oil, water, and gas were present in reservoir sand B at Well X4, while the other locations had a mix of oil, gas, and water. At Wells X3 and X4, reservoir sand C had a high proportion of oil and water, while gas, oil, and water were present in reservoir sand E at the same wells. The fluid type and column data for Wells X1, X2, and X5 were not available due to insufficient information, but information on the fluid type and column for four wells in the field being studied is provided in Tables 3 and 4.

Table 3. Presents the properties of the reservoir sand located in X Well 003.

Sand	B	C	D	E
Depth	2575-2650	2675-2710	2720-2770	2810-3250
Thickness	75	35	50	440
Volume of Shale	8.9	8.9	5.6	5.3
Porosity	22.5	21.70	19.52	13.2
Permeability	103.97	172.0	16.80	75.7
Water Saturation	19.88	27.50	26.85	23.04
Bulk Volume of Water	4.4	2.40	2.93	0.33
Fluid type	oil and water	oil and water	oil and water	gas, oil and water
Fluid contact/ Column		OUT:2675, OWC:2700	OUT:2725, OWC:2758	GUT:2800, GOC:2860, OUT:2818, OWC:2860
Nature of formation water	Not Irreducible	Irreducible at \approx 2% BVW	Irreducible at \approx 2% BVW	Irreducible at \approx 0.3% BVW

Table 4. Presents the properties of the reservoir sand located in X Well 004.

Sand	B	C	D
Depth	2620-2658	2675-2720	2752-2773
Thickness	28	45	21
Volume of Shale	4.9	5.6	5.3
Porosity	14.40	20.00	16.00
Permeability	105.1	68.1	73.7
Water Saturation	28.28	29.35	19.22
Bulk Volume of Water	3.39	3.25	0.28
Fluid type	Oil and water	Oil and water	Oil and water
Fluid contact / Column	OUT: OWC	OUT: OWC	OUT: OWC
Nature of formation water	Irreducible at \approx 3% BVW	Irreducible at \approx 3% BVW	Irreducible at \approx 0.2% BVW

According to Table 3, at a depth of 2675–2715 m, the hydrocarbon saturation of reservoir sand C was 72.50%, while water saturation was 27.50%. The oil was found at a depth of 2675 meters, with an oil-water contact (OWC) at 2700 meters. Sand B, with a shale volume of 8.9%, a porosity of 22.5, and a permeability of 54.24 mD, was determined to be irreducible, with estimated bulk volume water (BVW) of 4.4%. This indicates that more water than oil would be extracted from Sand B. Similarly, sands D and E were also found to be irreducible, with a higher oil concentration than water. Sand D had a hydrocarbon saturation of 73.15% and a water saturation of 26.7%, with oil found at a depth of up to 2725 meters. Meanwhile, Sand E had a hydrocarbon saturation of 76.96% and a water saturation of 23.04%, with oil discovered at depths up to 2818 meters and gas content found up to 2800 meters deep. Furthermore, Sand E had a gas-oil contact (GOC) at a depth of 2818 meters and an oil-water contact (OWC) at a depth of 2860 meters. Tables 3 and 4 provide information on the reservoir fluid type and column for four wells in the study field. However, there was insufficient data available to determine the fluid type and column for Wells X1, X2, and X5. The information in Table 3 enables the classification of reservoir sands in terms of fluid interactions, water saturation, and hydrocarbon saturation. Geoscientists and engineers may better comprehend the distribution and behavior of fluids inside the reservoir with the use of this knowledge. The irreducible nature of sands C, D, and E suggests a larger oil content relative to water and good oil extraction prospects. In order to gauge the extent and magnitude of hydrocarbon accumulations, the oil-water contact (OWC) and gas-oil contact (GOC) depths represent the boundaries between various fluid phases inside the reservoir. Fluid flow patterns and the distribution of hydrocarbons are impacted by reservoir heterogeneity, which includes distinct sands' variable porosity, permeability, and fluid characteristics. For reservoir modelling and production strategy optimization, an understanding of these variances is essential.

Table 4 displays the fluid content of reservoir sands B, C, and D in Well X4, indicating that all three reservoir sands were irreducible and contained only water and oil. Sand B had a water saturation of 28.28% and hydrocarbon saturation of 71.72%, while Sand C had a water saturation of 29.35% and hydrocarbon saturation of 70.65%, and Sand D had a water saturation of 19.22% and hydrocarbon saturation of 80.78%. However, the fluid capacity of the reservoirs in Wells X1, X2, and X5 could not be determined due to insufficient information. In some wells, only one neutron or density log was available, while in others, both logs were present but not in the

appropriate locations. Also, in some wells, neither log was accessible.

The field showed a wide range of bulk water volume values, suggesting that certain areas had not reached irreducible water saturation. In these areas, wet hydrocarbons, such as wet gas and oil, would be generated, while water-free hydrocarbons would be generated in areas with irreducible water saturation. The zones for water-free hydrocarbon production differed horizontally, vertically, and among reservoir sand units. Sand B in Well X3 was the only sand that was not irreducible, which suggests that any well drilled within these sands would produce hydrocarbons with some water content. Sands C, D, and E, on the other hand, would yield a considerable number of hydrocarbons without any water in the field.

The examination of the offshore "X Field" in the Niger Delta has yielded important geological and petrophysical data that might have a big influence on the hydrocarbon exploration and production industry. Improved reservoir performance estimates and increased hydrocarbon recovery result from the identification and characterization of lithofacies and sub-lithofacies as well as knowledge of their depositional environment and rock attributes. The discoveries on the extraordinary porosity and permeability of certain sand units, the dual function of shale as a hydrocarbon source and seal, and the dual function of shale as a hydrocarbon source and seal give vital insights for selecting the best drilling locations and selecting reservoir rocks. This knowledge can help with decision-making and may result in more successful and effective hydrocarbon extraction in related sectors.

This study focused on the particular "X Field" in the Niger Delta offshore, thus posing a constraint in terms of generalizability to other geological contexts. To validate and build upon the findings in many disciplines, more study is required. The comprehension of reservoir features and the precision of forecast might be improved by using cutting-edge analytical techniques including high-resolution imaging, geochemical analysis, and geophysical data integration. To assess flow characteristics, reservoir performance, and extraction difficulties, future studies should also incorporate reservoir engineering and production analyses. Overall, the "X Field" examination has had a substantial influence, but further study is required to fully comprehend and optimize hydrocarbon recovery techniques.

CONCLUSION

The investigation of the "X Field" identified four lithofacies, namely sand, sandy shale, shale sand, and shale, and five sub-lithofacies, namely coarse grain sand, medium grain sand, fine grain sand, very fine grain shale, and silty shale. In this area, shale functions as a seal both horizontally and vertically, while sand is the primary reservoir rock. The shoreface point bars and tidal channel sands originated from the fluvio-deltaic and deltaic front facies, whereas the shale units were produced near the shelf edge or slope in response to sea level changes. The rock properties in the "X Field" are influenced by the depositional environment and depth of burial. Shale layers have a dual role as both a source of hydrocarbons and a seal, while certain sand units have characteristics that make them suitable as reservoir rocks. The reservoir sands in the field are usually characterized by exceptional to outstanding porosity and permeability. Among all the sands, only sand E contained gas, but oil accumulation was widespread throughout the area. Other irreducible sands in the field have the potential to produce hydrocarbons free of water, but Sand B, being irreducible, would generate hydrocarbons that contain some water. The "X Field's" petrophysical properties were evaluated and found to be generally good to very good, with variations based on texture, depositional environment, and

grain composition. The sedimentary environment and reservoir quality of the “X Field” in the Niger Delta offshore were analyzed and found to be accurate. Valuable geological and petrophysical information was obtained from this examination that can be used to improve reservoir performance predictions and increase the recovery of hydrocarbons. This information can be used to identify the best drilling locations. Additionally, the data and information from this study will be beneficial for examining fields similar to the “X Field”.

AUTHOR CONTRIBUTIONS

Nwokoma Uzoma Esomchi and Agbasi Ebuka Okechukwu were responsible for designing and conducting the study, as well as collecting and analyzing the well log data. Azunna Enyinnaya Daniel and Ugwu Joshua Udoka assisted with data analysis and paper writing. All authors were involved in critically revising the manuscript for significant intellectual content and approved the final version for publication.

DECLARATION OF COMPETING INTEREST

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

REFERENCES

- [1] Harry TA, Etim CE, and Agbasi OE. Petrophysical Evaluation of H-field, Niger Delta Basin for Petroleum Plays and Prospects. *Materials and Geoenvironment*. 2022; **68**(2): 1-11. DOI: <https://doi.org/10.2478/rmzmag-2021-0020>.
- [2] Onyekuru OS, Oluchi NJ, Agbasi OE, Martyushev DA, and Chukwuma IJ. Evaluation of Depositional Environments and Reservoir Quality of Sediments in “OLI” Field, Offshore, Niger Delta, Nigeria. *Arabian Journal of Geosciences*. 2023; **16**(2): 138. DOI: <https://doi.org/10.1007/s12517-023-11250-2>.
- [3] Nwokoma E, Agbasi OE, and Dinneya O. Prediction of Litho-Porosity Using Incompressibility and Rigidity, Offshore Niger Delta, Nigeria. *Geoinformatica Polonica*. 2022; **21**: 31-42. DOI: <https://doi.org/10.4467/21995923GP.22.003.17081>.
- [4] Inyang NJ, Agbasi OE, Etuk SE, Akaolisa CCZ and Robert UW. Shale Gas Potential of Eocene Shale of Agbada Formation: A Paradigm Shift in Gas Resource Perception—A Case Study of the Niger Delta. *Arabian Journal of Geosciences*. 2022; **15**(12): 1141. DOI: <http://dx.doi.org/10.1007/s12517-022-10376-z>.
- [5] Reijers TJA. Stratigraphy and Sedimentology of the Niger Delta. *Geologos*. 2011; **17**(3). 133-162. DOI: <https://doi.org/10.2478/v10118-011-0008-3>
- [6] Doust H and Omatsola E. *Niger Delta* in Edwards JD and Santogrossi PA, eds., *Divergent/passive Margin Basins*, AAPG Memoir 48. Tulsa: American Association of Petroleum Geologists. 1990; 239-248.
- [7] Weber KJ and Daukoru EM. Petroleum Geological Aspects of Niger Delta, Tokyo. *Ninth World Petroleum Congress Proceedings*, 1975; **5**(2), 209-221.
- [8] Short KC and Stauble AJ. Outline of the Geology of the Niger Delta. *American Association of Petroleum Geologists*. 1967; **51**: 761-779. DOI: <https://doi.org/10.1306/5d25b57d-16c1-11d7-8645000102c1865d>.
- [9] Vauclin S, Mourier B, Dendievel AM, Noclin N, Piégay H, Marchand P, Vénisseau A, de Vismes A, Lefèvre I, and Winiarski T. Depositional Environments and Historical

- Contamination as a Framework to Reconstruct Fluvial Sedimentary Evolution. *Science of the Total Environment*. 2021; **764**: 142900. DOI: <https://doi.org/10.1016/j.scitotenv.2020.142900>.
- [10] Nton ME and Rotimi S. Reservoir Characteristics and Palaeo Depositional Environment of Duski Field, Onshore, Niger-Delta, Nigeria. *Global Journal of Geological Sciences*. 2016; **14**(1): 49. DOI: <https://doi.org/10.4314/gjgs.v14i1.5>.
- [11] Inyang NJ, Okwueze EE, and Agbasi OE. Detection of Gas Sands in the Niger Delta by Estimation of Poisson's Dampening-Factor (PDF) Using Wireline Log Data. *Geosciences*. 2015; **5**(1): 46-51.
- [12] Agbasi OE, Chukwu GU, Igboekwe MU, and Etuk SE. Pore Fluid and Lithology Discrimination of a Well in the Niger Delta Region Using Elastic Parameters. *World News of Natural Science*. 2018; **17**: 75-88.
- [13] Agbasi OE, Sen S, Inyang NJ and Etuk SE. Assessment of Pore Pressure, Wellbore Failure and Reservoir Stability in the Gabo Field, Niger Delta, Nigeria - Implications for Drilling and Reservoir Management, *Journal of African Earth Sciences*. 2021; **173**: 104038. DOI: <https://doi.org/10.1016/j.jafrearsci.2020.104038>.
- [14] Etuk NO, Aka MU, Agbasi OE, and Ibuot JC. Evaluation of Seismic Attributes for Reservoir Characterization over Edi Field, Niger delta, Nigeria Using 3D Seismic Data. *International Journal of Advanced Geosciences*. 2020; **8**(2): 168-172. DOI: <https://doi.org/10.14419/ijag.v8i2.31043>.
- [15] Poston SW, Berry P, and Molokwu FW. Meren Field – The Geology and Reservoir Characteristics of a Nigerian Offshore Field. *Journal of Petroleum Technology*. 1981; **35**(11): 2095-2104. DOI: <https://doi.org/10.2118/10344-PA>.
- [16] Asquith G and Krygowski D. *Basic Well Log Analysis*. AAPG Methods in Exploration Series 16. Tulsa, Oklahoma: The American Association of Petroleum Geologists; 2004.
- [17] Enikanselu PA and Ojo AO. Statistical Analysis and Evaluation of Lithofacies from Wireline Logs over 'Beelema' Field, Niger Delta, Nigeria. *Journal of Petroleum and Gas Engineering*. 2012; **3**(2): 26-34.
- [18] Larionov VV. Borehole Radiometry: Moscow, U.S.S.R. *Logging Symposium Paper*. 1969; **10**: 26.
- [19] Agbasi OE, Akankpo AO, and Essien UE. Estimation of Reservoir Potentials of Two Wells in Niger Delta Region, Nigeria. *Journal of Geosciences and Geomatics*. 2017; **5**(2): 87-95. Available from: <http://pubs.sciepub.com/jgg/5/2/5>.
- [20] Archie GE. The Electrical Resistivity Log as an Aid in Determining Some Reservoir Characteristics. *Transaction of the AIME*, 1942; **146**(01): 54-62. DOI: <https://doi.org/10.2118/942054-G>.
- [21] Adepelumi AA, Alao OA, and Kutemi TF. Reservoir Characterization and Evaluation of Depositional Trend of the Gombe Sandstone, Southern Chad Basin, Nigeria: *Journal of Petroleum and Gas Engineering*. 2011; **2**(6): 118-131. Available from: <https://oa.mg/work/10.5897/jpge.9000042>.
- [22] Ojo O, Agbasi OE, Namdie I, Etuk S, and Robert U. Prediction of Pore Fluid and Lithology Using Incompressibility and Rigidity, Offshore Niger Delta, Nigeria. *International Journal of Earth Sciences Knowledge and Applications*. 2020; **2**(3): 109-120. Available from: <http://www.ijeska.com/article/view/34>.
- [23] Akpabio I, Ibuot JC, Agbasi OE, and Ojo OT. Petrophysical Characterization of Eight Wells

- from Wire-line Logs, Niger Delta Nigeria, *Asian Journal of Applied Science*. 2014; 2(2): 105-109. Available from: <https://ajouronline.com/index.php/AJAS/article/view/540>.
- [24] Agbasi EO, Etuk ES, Abdulaziz MA, Joseph IN, and Robert WU. Estimation of Original Oil in Place Using Pickett's and Buckle's Plots, Offshore Niger Delta, Nigeria. *Petroleum and Coal*. 2020; 62(4): 1279-1288.
- [25] Inyang NJ, Agbasi OE, and Akpabio GT. Integrated Analysis of Well Logs for Productivity Prediction in Sand-shale Sequence Reservoirs of the Niger Delta—A Case Study. *Arabian Journal of Geoscience*. 2021; 14(7): 587. DOI: <https://doi.org/10.1007/s12517-021-06965-z>.
- [26] Olayiwola AM and Bamford KM. Depositional Environment and Reservoir Characterization of the Deep Offshore Upper Miocene to Early Pliocene Agbada Formation, Niger delta, Nigeria. *Journal of African Earth Sciences*. 2019; 159: 103578. DOI: <https://doi.org/10.1016/j.jafrearsci.2019.103578>.
- [27] Friday UK, Anthony UO, Ezekiel OI, and James US. Analysis of Depositional Environments of Uk Field Reservoir Sands in Niger Delta Basin, Nigeria. *The American Journal of Applied Sciences*, 2022; 04(12): 05–32. DOI: <https://doi.org/10.37547/tajas/volume04issue12-02>.
- [28] Okoli AE, Edward AJ, Ehirim CN, Dosunmu A, and Agbasi OE. Paleoenvironmental Reconstruction of an Onshore Field, Coastal Swamp Depobelt Niger Delta. *Geoscience*. 2019; 9(1), 18-26. Available from: <http://article.sapub.org/10.5923.j.geo.20190901.03.html>.
- [29] Okoli AE, Agbasi OE, Lashin AA, and Sen S. Static Reservoir Modeling of the Eocene Clastic Reservoirs in the Q-Field, Niger Delta, Nigeria. *Natural Resources Research*. 2021; 30(2): 1411–1425. DOI: <https://doi.org/10.1007/s11053-020-09804-2>.
- [30] Okoli AE and Agbasi OE. Inclusive Reservoir Characterization from Rock Physics and Sequence Stratigraphic Analyses of Middle Miocene, Niger delta. *Petroleum Research*. 2021; 6(3), 213–223. DOI: <https://doi.org/10.1016/j.ptlrs.2021.01.001>.
- [31] Schlumberger. *Log Interpretation, Principles and Applications*. Houston: Schlumberger Wireline and Testing. 1989; 21-89.