Journal of Basic Physical Research ISSN: 2141-8403 Prints, 2141-8411 Online
Vol.14, Issue 2, October, 2025, pp. 22 – 42, Available online at https://journals.unizik.edu.ng/jbpr/

PETROPHYSICAL ANALYSIS OF HYDROCARBON RESERVOIRS IN THE CALABAR FLANK FOR RESERVES ESTIMATION

Bankole, Olusegun Olayinka[1], *Gabriel Efomeh Omolaiye[2], and Jimoh Ajadi[1]
[1]Department of Geology and Mineral Science, Kwara State University, Malete, Kwara State, Nigeria
[2]Department of Applied Geophysics, University of Ilorin, PMB 1515, Ilorin, Kwara State, Nigeria
Corresponding Author:
Gabriel Efomeh Omolaiye, Department of Geophysics, University of Ilorin, PMB 1515, Ilorin, Nigeria, +234 809 966 4112, ***gab_omolaiye@yahoo.co.uk,***

Abstract
Despite the favourable geological settings of the Calabar Flank for hydrocarbon generation and accumulation, the lack of quantitative reservoir evaluation remains a limitation in the South-eastern part of Nigeria. This study applies petrophysical analysis to characterize reservoir quality and estimate hydrocarbon reserves in this region using well data (gamma ray, resistivity, density and sonic log) from selected wells, which were interpreted to derive key parameters such as gross sand, net sand, gross pay, net pay, porosity, water saturation (Sw), hydrocarbon saturation (Sh), net-to-gross ratio (NTG) and bulk volume of water (BVW). The results of this study reveal continuous reservoirs with gross sand and pay thicknesses of up to 879 ft and NTG values between 0.81 and 0.95, indicating high reservoir continuity and minimal shale intercalation. Porosity values of 0.37 reflect excellent pore space development, while water saturation remains a relatively low value of 0.09 and hydrocarbon saturation values as high as 0.91, highlighting significant hydrocarbon presence. Low BVW values further demonstrate effective hydrocarbon displacement. All analysed intervals were classified as oil-down-to (ODT) systems that indicate laterally continuous oil-bearing zones. These findings highlight Calabar Flank's high-quality reservoir properties and its potential for substantial commercial hydrocarbon reserves. This study provides quantitative insights into reservoir behaviour, strengthens the understanding of hydrocarbon prospectivity within the region, and offers practical guidance for exploration and development strategies.

Keywords: *Calabar Flank, Petrophysical Analysis, Hydrocarbon Prospectivity, Reservoirs Estimation.*

Introduction

Accurate estimation of hydrocarbon volumes in place and recoverable reserves is significant, particularly in emerging or underexplored basins where early-stage data availability is often limited (Ahmed et al., 2024; Muther et al., 2021; Omigun & Alaminiokuma, 2020; Mheluka & Mulibo, 2018). In an era marked by increasing global energy demand and a strategic shift toward unlocking inland and frontier basins, the Calabar Flank within Nigeria's Lower Benue Trough has attracted increasing geological interest (Olayiwola et al., 2023; Selema et al., 2023; Ekwok et al., 2021; Ogidi et al., 2021). Although the Niger Delta remains Nigeria's primary hydrocarbon province, recent studies have highlighted the promising exploration potential of the Calabar Flank (Isaac et al., 2024; Aka et al., 2022; Ekwok et al., 2021; Nton & Adeyemi, 2021). However, despite its geological proximity to prolific hydrocarbon provinces like the Niger Delta, the Calabar Flank has received limited attention in exploration activities and a notable gap in detailed quantitative reserve assessments (Temple et al., 2024; Selema et al., 2023). This underscores the need for petrophysical analysis to enhance our understanding of the reservoir properties and accurately estimate reserves in this promising but understudied region.

The Calabar Flank is located on the southeastern edge of the Lower Benue Trough, characterized by Cretaceous sedimentary sequences that have shown favourable conditions for hydrocarbon generation and accumulation (Selema et al., 2023; Ekwok et al., 2021; Boboye & Okon, 2014). These Cretaceous formations are known to contain key elements of the

petroleum system, including source rocks, moderate-to-good quality reservoirs, and well-defined structural closures. Previous geological and geophysical studies have documented the presence of viable source rocks and adequate reservoir units within the Calabar Flank (Selema et al., 2023). However, the absence of comprehensive quantitative reserve assessments has hindered the commercial development of discovered resources. Due to advancements in petrophysical analysis and access to high-quality subsurface data, it is now possible to analyse reservoir properties with sufficient accuracy for reserve estimation and early field evaluation (Onita et al., 2023; Al-Rubaye et al., 2021; Shah et al., 2021). The lack of reservoir evaluation studies within the basin presents a significant knowledge gap, as few studies provide qualitative assessments of reservoir potential in the region without detailed quantitative analysis of well log-derived petrophysical parameters. This research gap has hindered a comprehensive understanding of reservoir heterogeneity, fluid distribution, and reserve potential of Calabar Flank, which addresses this gap is essential to support exploration decisions, guide investment and enhance the utilisation of Nigeria's inland basin resources.
In the oil and gas industry, reserves indicate the volume of hydrocarbons that can be recovered under current economic and operational conditions (Shah et al., 2021; Paul et al., 2018). Estimating these reserves requires a thorough understanding of the subsurface, including the reservoir's geometry, the quality of reservoir rocks, and the distribution of hydrocarbons within pore spaces, with petrophysical analysis from well logs remaining the most reliable tool for initial reserve assessment (Sadeq et al., 2024; Maju-Oyovwikowhe & Ighodaro, 2023; Bate et al., 2022; Al-Rubaye et al., 2021; Omigun & Alaminiokuma, 2020; Al Fatta et al., 2018; Amigun & Odole, 2013). Petrophysical analysis converts raw well log data into meaningful reservoir parameters such as porosity, water saturation, net-to-gross ratio, and permeability (Maju-Oyovwikowhe & Ighodaro, 2023; Omigie & Alaminiokuma, 2020; Mheluka & Mulibo, 2018; Paul et al., 2018; Amigun & Odole, 2013). These parameters are important inputs for the volumetric formula used to calculate hydrocarbons initially in place (Shah et al., 2021; Saadu & Nwankwo, 2018; Essien et al., 2017; Ahammod et al., 2014). The deterministic volumetric method is used during early field evaluation to estimate HIIP through the relationship among net pay thickness, porosity, hydrocarbon saturation, reservoir extent, and formation volume factor (Bate et al., 2022; André et al., 2022; Shah et al., 2021; Al Fatta et al., 2018; Saadu & Nwankwo, 2018). The accuracy of these estimates relies on the quality of input data and the robustness of the interpretation workflow. Thus, petrophysical analysis plays a vital role in reducing uncertainties and increasing confidence in reserve estimates (Sadeq et al., 2024; Al-Rubaye et al., 2021; Amigun & Odole, 2013).

This study is designed to provide a detailed petrophysical evaluation of hydrocarbon reservoirs within the Calabar Flank using well log data through the analysis of critical reservoir parameters, including gross and net sand thickness, pay thickness, porosity, water and hydrocarbon saturations, bulk volume of water and net-to-gross ratio. The primary aim of this study is to evaluate the reservoir quality within Calabar Flank, with the objectives to characterise the petrophysical properties of the hydrocarbon-bearing reservoir, quantify the parameters for reserve estimation, and provide insights that support hydrocarbon exploration and guide field development strategies in Nigeria's inland basin.

Location and Geology of Calabar Flank

Location of the Calabar Flank

The study area is situated within the Calabar Flank, first described by Murat (1972) as part of the southern Nigerian sedimentary basin characterised by crustal blocking faulting, which was formed during early rifting associated with the separation of South America from Africa and the opening of the South Atlantic during Albain times (Ekpo et al., 2013; Ekpo et al., 2012;

Okiwelu et al., 2010; Whiteman, 1982; Murat, 1972). The Calabar Flank lies within latitudes [5°0′0″n and 5°15′0″n] and longitudes [8°15′0″e and 8°30′0″e], bounded by the Oban Massif to the north, the Cameroon volcanic line to the east, the Ikpe platform to the west, and the Calabar Hinge to the south. It occupies a position at the extreme northeast of the Niger Delta Basin, as shown in figure 1 (Temple et al., 2024; Ekwok et al., 2021; Boboye & Okon, 2014; Reijers & Petters, 1987).

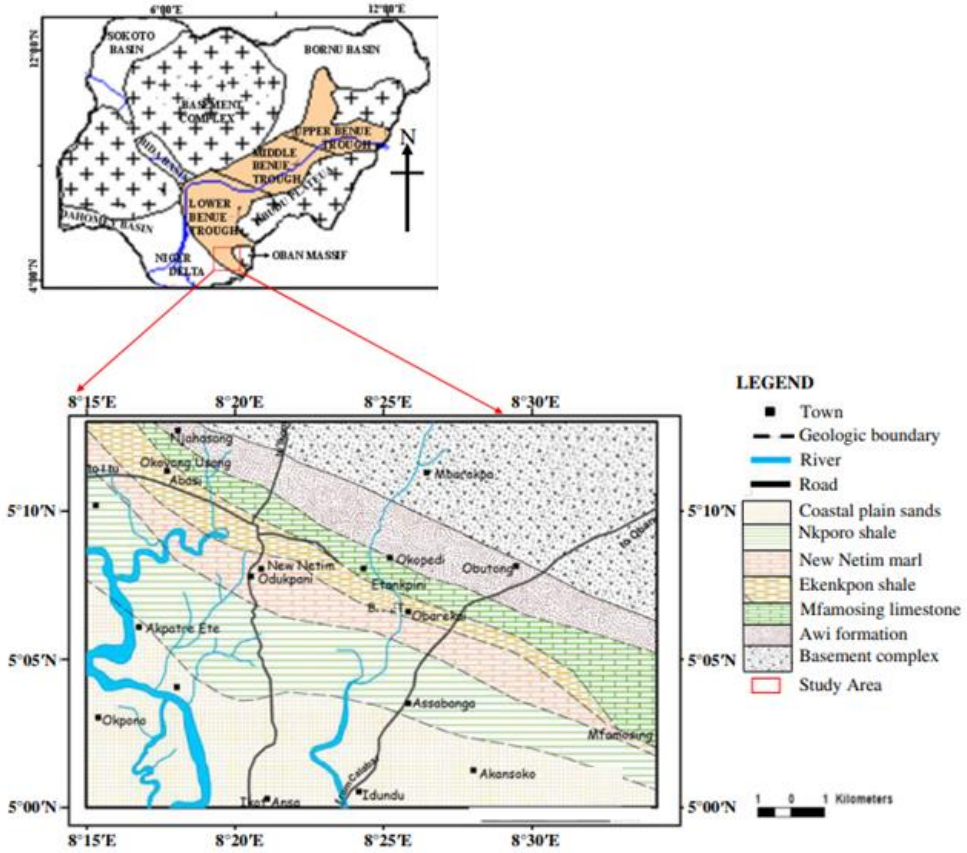


Figure 1: Geological Map of Calabar Flank showing Stratigraphic Sequence Modified from (Ekwok et al., 2021)

Stratigraphic Setting of Calabar Flank

The age of the sedimentary rock in the Calabar Flank ranges from Aptian to Campanian-Maastrichtian, with sedimentation beginning during the deposition of the Awi Formation. The sedimentary sequences in the Calabar Flank are divided into eight distinct formations, as identified by various researchers, as shown in Figure 2, which displays the stratigraphic sequence of the Calabar Flank (Odumodu, 2012; Essien et al., 2005; Petters et al., 1995; Edet & Nyong, 1993; Adeleye & Fayose, 1978). Figure 3 presents a geological cross-section of the Calabar Flank, illustrating the primary structural features and sequences.

TERTIARY	AGE	FORMATION	LITHOSTRATIGRAPHIC DESCRIPTION	DEPOSITIONAL
	OLIGOCENE TO RECENT	Benin Formation	Pebbly sands and gravels	Continental
	EOCENE	Ameke Formation	Medium-grained pebbly sandstones, clayey sandstones, calcareous silts, clay and thin limestones	Paralic
	PALEOCENE	Imo Shale	Clayey shale, clay ironstones bands, thin sandstone and sandy limestone bands	Paralic
CRETACEOUS	MAASTRICHTIAN	Nkporo Shale	Gypsiferous dark grey shales with ironstone intercalation	Shallow Marine
	CAMPANIAN		Uncomformity	
	SANTONIAN	New Netim Marl	Marlstones with shale intercalations	Marine
	CONIACIAN			
	TURONIAN	Ekenkpon Shale	Thick black pyritic shales with intercalations of mudstones, sandstones, ironstones and oyster beds	Marine
	CENOMANIAN			
	ALBAIN	Mfamosing	Stromatollitic fossiliferous limestones	Marine
	APTIAN	Awi Formation	Arkosic sandstones interbedded with shales	Fluvio – deltaic
	PRECAMBRIAN	Oban Basement	Crystalline Basement Rocks	

Figure 2: Stratigraphic Sequence of Calabar Flank Modified after (Odumodu, 2012)

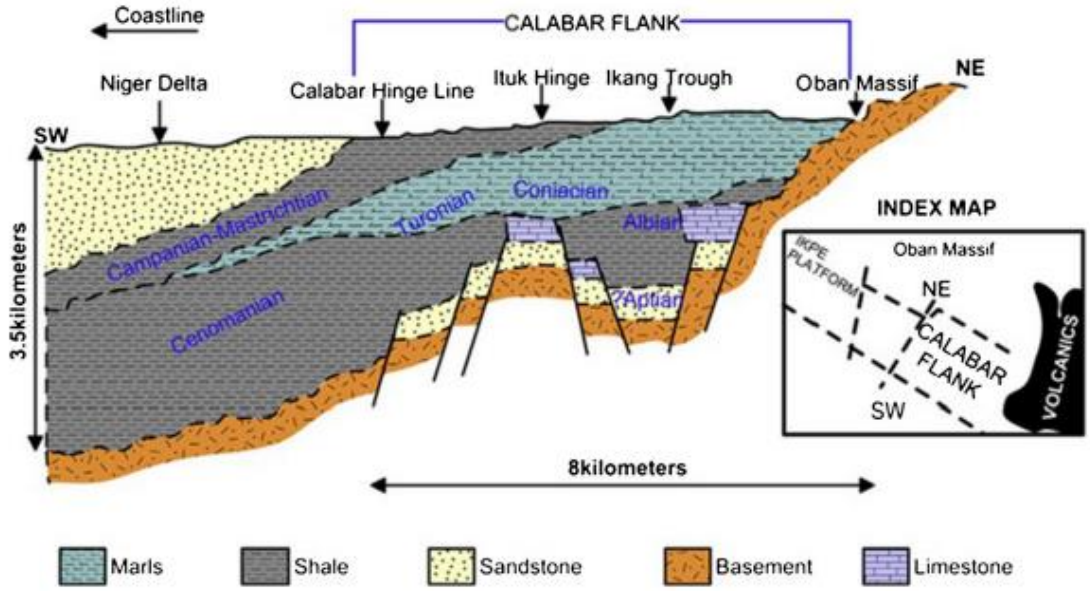


Figure 3: Idealized geological cross-section of Calabar flank showing the primary structural features and sequences adapted from (Edet & Nyong, 1993).

Awi Formation

The sedimentary sequence in the Calabar Flank begins with the Awi Formation, which lies as the base of the sequence resting unconformably above the Precambrian basement complex (Adeleye & Fayose, 1978). The Awi Formation is the oldest sedimentary deposit and is mainly composed of fluvio-deltaic deposits, including shales, mudstones, and arkosic sandstones of Aptian age (Ekpo et al., 2013). These sediments are believed to have been deposited through traction processes, either as bedloads or as contact loads, as evidenced by their presence in various bedform structures (Ekhalialu et al., 2016; Ramanathan & Kumaran, 1981). Petrographic and provenance studies indicate that the source materials originated from acidic igneous rocks, granitic pegmatites, and related metamorphic rocks typical of the southwestern Nigerian basement terrain (Okon & Ojong, 2019; Essien et al., 2017).

Mfamosing Formation

The Mfamosing Formation is a carbonate-dominated formation that directly overlies the Awi Formation. It is dated to the Middle Albian based on ammonite fossilization, with four recognizable facies identified within it (Reijers, 1998; Reijers & Petters, 1987) [42, 43]. The Mfamosing Formation is part of the Odukpani Group, with its thickness increasing basinward, and is mainly exposed along the Oban Massif. Stratigraphic records suggest these carbonates were deposited before the tectonic deformation associated with the Santonian orogeny, which was accompanied by basic volcanic activity and stratigraphic disconformities (Reijers, 1998; Petters et al., 1995).

Ekenkpon Shale Formation

The Ekenkpon Shale overlies the Mfamosing Formation and marks the beginning of a significant marine transgressive phase starting in the Late Albian and continuing into the Turonian, with a brief regression around the Cenomanian (Nton et al., 2018; Ilori, 2016; Nyong & Ramanathan, 1985). The Ekenkpon Shale Formation mainly comprises dark, fissile shales interbedded with calcareous mudstones, marls, and occasional shell-rich layers that indicate two major transgressive cycles: one corresponding to the Eze-Aku Shale of the Abakaliki Fold Belt, and the other associated with the Awgu Shale, which in the Calabar Flank is equivalent

to the New Netim Marl (Oluwajana & Ehinola, 2018). These sequences together correlate with the broader Nkalagu Formation.

New Netim Marl Formation

The New Netim Marl Formation was deposited after the Ekenpon Shale Formation, and it consists of thick marl interbedded with thin shale seams that conformably overlie the Ekenpon Shale. This unit is dated to the Coniacian stage, and its deposition followed a period of erosion or non-deposition, which explains the absence of Santonian to early Campanian sediments in the Calabar Flank (Ilori, 2016). Mineralogically, the New Netim Marl formation includes shales with fossil remnants, calcite, and quartz, which display nodular textures and a distinctive yellow colouration (Ilori, 2016).

Nkporo Shale Formation

In the Calabar Flank, the Nkporo Shale is linked to the Campanian–Maastrichtian period, lying unconformably above the New Netim Marl. It consists of dark grey to bluish-black carbonaceous shales that are fragile to brittle, interbedded with marly, silty, sandy shales, and mudstones (Harry et al., 2022). This formation was laid down during a renewed marine invasion following the Santonian tectonic uplift and regional subsidence, which are laterally equivalent to formations like the Owelli Sandstone and Enugu Shale (Short & Stauble, 1967). West of the Niger River, the Nkporo Shale extends from the Campanian to the late Maastrichtian and represents the last Cretaceous unit before the deposition of the Tertiary Benin Formation, known for its pebbly sandstones (Ogidi et al., 2021; Short & Stauble, 1967). Subsequent formations include the Imo Shale, Ameki Formation, and Benin Sandstone (Short & Stauble, 1967).

Imo Shale Formation

The Imo Shale Formation is the main rock-stratigraphic unit from the Palaeocene epoch, mainly characterised by bluish-gray clays and black shales, with occasional bands of calcareous sandstone, marls, and limestone layers (Udo et al., 2023; Reyment, 1965). This formation represents the Palaeocene period and is considered the surface equivalent of the Akata Formation in the subsurface of the Niger Delta (Short & Stauble, 1967; Reyment, 1965). In western Nigeria, it transitions into the Ewekoro Formation, which is rich in shelly limestone and is important for cement production. In eastern regions, the shale becomes more sandy or silty, sometimes grading into shaly sandstone (Short & Stauble, 1967). The Imo Shale Formation is directly overlain by the Ameki Formation, marking the beginning of a major regressive phase.

Ameki Formation

The Ameki Formation began during the early Eocene and was deposited on the Imo Shale Formation (Udo et al., 2023; Short & Stauble, 1967). Over time, especially during the Middle to Late Eocene, this formation exhibited a significant increase in sand content, marking the onset of regional regression and deltaic sedimentation (Udo et al., 2023). The Ameki Formation mainly consists of shale west of the Niger, which gradually transitions north of Lagos to the sandier Ilaro Formation and the lagoon-influenced Oshosun clays (Short & Stauble, 1967). Additionally, the lithology of the Ameki is more complex in the eastern Niger, featuring a mixture of sandstone, shale, marl, and fossiliferous limestone beds, indicating a shallow marine depositional environment affected by coastal sediment supply (Udo et al., 2023; Short & Stauble, 1967).

Benin Formation

The Benin Formation is the youngest rock stratigraphic unit within the Calabar Flank, dating from the Miocene to Recent times, and is commonly known as the Coastal Plain Sands. It mainly consists of unconsolidated sands, often cross-bedded with minor clay layers, reflecting deposition in near-shore to continental environments. This formation extends across Nigeria's coastal regions and lies adjacent to the Deltaic Plain Sediments (Short & Stauble, 1967; d'Almeida et al., 2016; Reyment, 1965).

Materials and Methods

Materials

The primary data used for the analysis include gamma ray (GR), spontaneous potential (SP), resistivity, density, and sonic logs from selected exploration wells. The petrophysical evaluation aims to characterize reservoir rock and fluid properties and delineate productive zones for reserves estimation. Techlog software was employed due to its advanced capabilities in well log interpretation and reservoir characterisation. Its robust tools and interactive interface allowed for the accurate derivation of petrophysical parameters and facilitated the seamless integration of results for a comprehensive reservoir evaluation. Figure 4 presents the basemap of the study area, and Figure 5 displays the methodology workflow chart used in this study. Table 1 provides the header information, while Table 2 lists the log inventory within the study field.

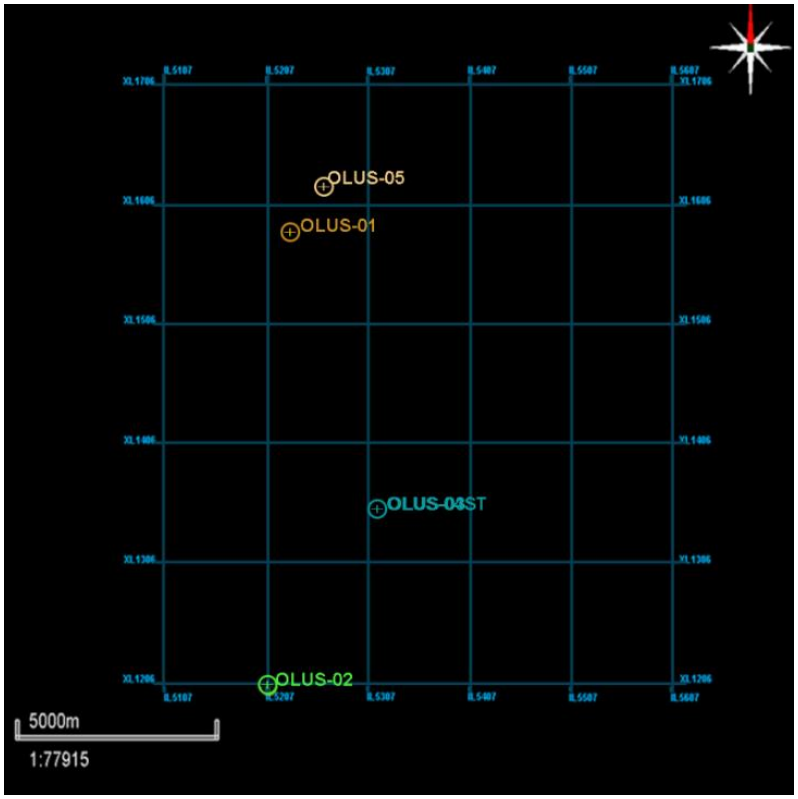


Figure 4: Basemap coverage of the study area

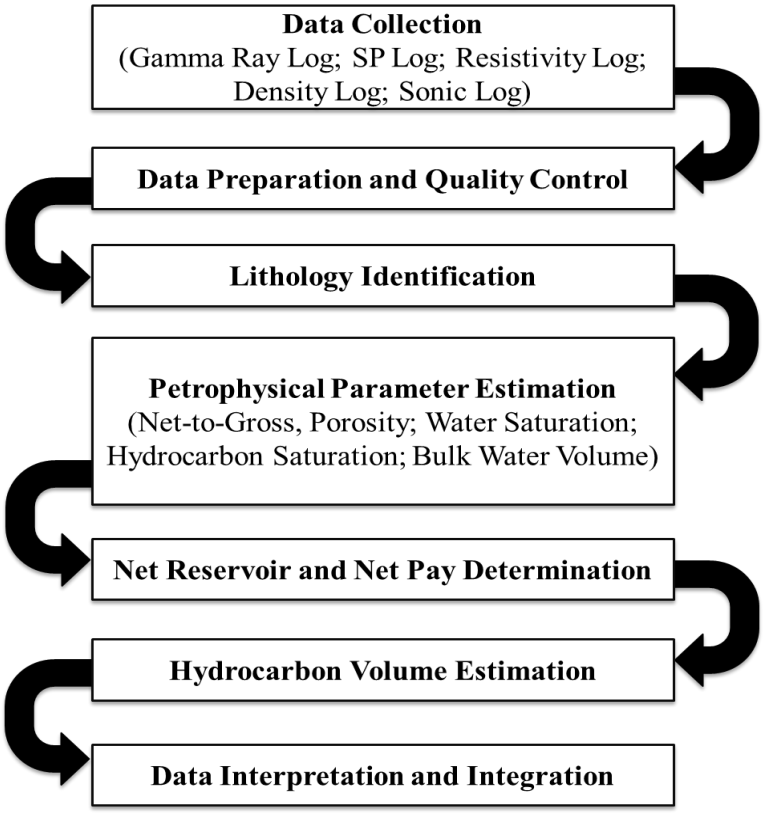


Figure 5: Methodology Workflow Chart within this Study

Table 1: Header information

Header Information				
WELL NAME	**X (m)**	**Y (m)**	**KB (ft)**	**TD (ft)**
OLUS-01	620103	112012	18.59	6000
OLUS-02	619555	102547	51.2064	7540
OLUS-03	622246	106200	221.03	10522
OLUS-04ST	622219.3	106200.8	221.03	11277
OLUS-05	N/A	N/A	N/A	10,272

Table 2: Available Logs and Well Information within the Study Field

WELL (ft)	GR	SP	RESISTIVITY	NEUTRON	DENSITY	SONIC
OLUS–02	--	76 – 397 ft; 2543 – 7440 ft	76 – 397 ft; 2543 – 7440 ft	---	76 – 397 ft; 2543 – 7440 ft	76 – 397 ft ; 2543 – 7440 ft
OLUS–03	--	31.13 – 10,549 ft	31.13 – 10,549 ft	---	31.13 – 10,549 ft	31.13 – 10,549 ft
OLUS–04ST	1909.43 – 6030 (ft)	1909.43 – 6030 ft	-	---		1909.43 – 6030 ft
OLUS-05	998.77 – 10,178 (ft)	--	998.77 – 10,178 ft	---		

Methodology

Quantitative petrophysical evaluation was performed using established mathematical formulas and empirical relationships. Relevant wireline log parameters, such as Volume of Shale, Porosity, Water Saturation, Hydrocarbon Saturation, and Bulk Water Volume, were used to assess reservoir quality. These computations helped interpret reservoir characteristics and contributed to estimating hydrocarbon reserves within the Calabar Flank.

Volume of Shale (V_{sh})

The volume of shale plays an essential role in assessing reservoir quality, as high shale content can decrease porosity, permeability, and hydrocarbon saturation, thus negatively affecting fluid flow and storage capacity. Shale volume is usually estimated using gamma-ray log data, based on the assumption that shales emit more natural radioactivity than clean sandstones (Chikiban et al., 2022; Omigie & Alaminiokuma, 2020; Nwaezeapu et al., 2019; Anyiam et al., 2017). The gamma-ray index (IGR) is first calculated with the formula in equation (1), and the Larionov tertiary rock method is described by the formula in equation (2) (Oyeyemi et al., 2017; Larionov, 1969):

$$\boldsymbol{GR_{index}} = \frac{\boldsymbol{GR - GR_{matrix}}}{\boldsymbol{GR_{shale} - GR_{matrix}}} \qquad \textbf{Eqn. 1}$$

$$\boldsymbol{V_{sh}} = \mathbf{0.083} * (\mathbf{2}^{(\mathbf{3.7} * \boldsymbol{GR_{index}})} - \mathbf{1}) \qquad \textbf{Eqn. 2}$$

Where $\boldsymbol{GR}$ is the gamma-ray log reading within the zone of interest; $\boldsymbol{GR_{matrix}}$ is the gamma-ray log reading in 100% matrix rock; $\boldsymbol{GR_{shale}}$ is the gamma-ray log reading in 100% shale; $\boldsymbol{GR_{index}}$ is the gamma-ray index and $\boldsymbol{V_{sh}}$ is the volume of shale.

Net-to-Gross (NTG) estimation

Net-to-gross sand estimation is a vital part of reservoir evaluation that assesses the proportion of sand with reservoir-quality properties compared to the total gross thickness of the sand-bearing formation (Oyeyemi et al., 2017). It helps quantify the amount of effective sand (net sand) that meets specific criteria for porosity, shale content, and fluid saturation, thereby aiding in the storage and flow of hydrocarbons. The net-to-gross (NTG) sand ratio is calculated using the formula in equation 3 (Nwaezeapu et al., 2019):

$$\boldsymbol{Net - to - Gross\ (NTG)} = \frac{\sum(\boldsymbol{Net\ Int})}{\sum(\boldsymbol{Gross\ Int})} \qquad \textbf{Eqn. 3}$$

Where Net Int. is the interval of the net pay section of the reservoir, Gross Int. is the interval of the entire reservoir. High NTG sand values indicate well-developed, cleaner sands with better reservoir quality, while low NTG values may suggest significant shale intercalation or poor porosity (Oyeyemi et al., 2017; Al-Baldawi, 2014). Accurate NTG sand estimation is essential for reserve calculations and analysis, and field development planning.

Determination of porosity (Ø)

Porosity is a fundamental reservoir property that measures the amount of void spaces within a rock that can potentially hold fluids (Essien et al., 2017). It is expressed as a fraction of the total rock volume (Saadu & Nwankwo, 2018). Porosity can be divided into total porosity, which includes all pore spaces, and effective porosity, which only considers interconnected pores that contribute to fluid flow.

Total porosity is calculated using the formula from equation 4 (Nwaezeapu et al., 2019; Saadu & Nwankwo, 2018):

$$\emptyset_{\boldsymbol{D}} = \frac{(\boldsymbol{\rho_{ma}} - \boldsymbol{\rho_b})}{(\boldsymbol{\rho_{ma}} - \boldsymbol{\rho_{fluid}})} \qquad \textbf{Eqn. 4}$$

Where $\emptyset_D$ is the total porosity; $\boldsymbol{\rho_{ma}}$ is the density of the rock matrix; $\boldsymbol{\rho_b}$ is the bulk density read from the log and $\boldsymbol{\rho_{fluid}}$ is the density of the fluid occupying the pore spaces. Accurate porosity estimation is vital for evaluating the storage capacity of the reservoir and plays a key role in volumetric reserve calculations.

Moreover, effective porosity ($\emptyset_e$) is the portion of a rock's total porosity that consists of interconnected pore spaces capable of transmitting fluids, which excludes isolated pores and those occupied by bound water, particularly in shaly formations, where clay-bound water can significantly distort total porosity readings. Effective porosity is a more accurate representation of the reservoir's ability to store and transmit hydrocarbons. It is typically derived by correcting total porosity for the presence of shale using the formula in equation 5 (Anyiam et al., 2017):

$$\emptyset_{\boldsymbol{e}} = \emptyset_D - \boldsymbol{V_{sh}}\left(\frac{(\boldsymbol{\rho_{ma}} - \boldsymbol{\rho_{sh}})}{(\boldsymbol{\rho_{ma}} - \boldsymbol{\rho_{fluid}})}\right) \qquad \textbf{Eqn. 5}$$

Where $\emptyset_D$ is total porosity, $\boldsymbol{\rho_{ma}}$ is the density of the rock matrix, $\boldsymbol{\rho_{sh}}$ is the density of the clay point interval, and $\boldsymbol{\rho_{fluid}}$ is the density of the fluid occupying the pore space

Water Saturation (S_w)

Water saturation (S_w) represents the fraction of pore volume in a reservoir rock that is filled with water. Water saturation is typically derived from resistivity logs using Archie's equation, as shown in equation 6 below (Nwaezeapu et al., 2019; Oyeyemi et al., 2017l; Al-Baldawi, 2014):

$$\boldsymbol{S_w} = \sqrt[n]{\frac{\boldsymbol{a} * \boldsymbol{R_w}}{\boldsymbol{R_t} * \emptyset^{\boldsymbol{m}}}} \qquad \textbf{Eqn. 6}$$

Where **a** is the tortuosity factor; **m** is the cementation exponent; Ø is porosity; $\boldsymbol{R_w}$ is the formation water resistivity, $\boldsymbol{R_t}$ is the true resistivity, and **n** is the saturation exponent. Low water saturation values typically indicate higher hydrocarbon content, making Sw a key indicator of reservoir quality and potential productivity.

In addition, $\boldsymbol{R_w}$ is the water resistivity at the formation temperature is calculated using equation 7 below.

$$\boldsymbol{R_w = \frac{\emptyset^m * R_0}{a}} \qquad \textbf{Eqn. 7}$$

$\boldsymbol{R_0}$ is the resistivity of the reservoir when the entire fluid is water.

Hydrocarbon Saturation ($\boldsymbol{S_h}$)

Hydrocarbon saturation refers to the fraction of pore space in a reservoir rock that is occupied by hydrocarbons rather than water. It is an essential parameter for determining how much of the reservoir's pore space contains hydrocarbons that can be potentially recovered. Hydrocarbon saturation is calculated as the complement of water saturation using equation 8 below (Nwaezeapu et al., 2019; Al-Balwawi, 2014; Asquith & Krygowski, 2004):

$$\boldsymbol{S_h = 1 - S_w} \qquad \textbf{Eqn. 8}$$

Where $\boldsymbol{S_w}$ is water saturation

Moreover, Pickett plots were generated for the wells to validate the derived petrophysical parameters. The plots effectively distinguish hydrocarbon-bearing from water-bearing intervals, showing trends that correspond to low water saturation and high hydrocarbon saturation in both wells.

Bulk Water Volume (BVW)

Bulk Volume Water (BVW) is the fraction of the total rock volume occupied by water in the pore spaces, and it is calculated as shown in Equation 9 (Oyeyemi et al., 2017; Al-Baldawi, 2014; Asquith & Krygowski, 2004).

$$\boldsymbol{BVW = \emptyset * S_w} \qquad \textbf{Eqn. 9}$$

Results

Tables 4 and 5 display petrophysical properties of wells across OLUS–03 (Sand A), OLUS–04ST (Sand A) and OLUS–03 (Sand B) within the study field.

Table 4: shows Top and Base Properties Across the Wells.

SANDS	WELLS	TOP MD (ft)	TVDSS (ft)	BASE MD (ft)	TVDSS (ft)
Sand A	OLUS–03	4942.54	-4719.94	4985.69	-4763.05
Sand A	OLUS-04ST	4894.80	-4670.14	4944.24	-4718.59
Sand B	OLUS-03	9364.84	9140.8	10244.0	10019.8

Table 5: shows the petrophysical well logs properties across the Wells.

WELLS	GROSS SAND (ft)	NET PAY	POROSITY	WATER SATURATION	NTG	REMARKS
OLUS–03	43.11	34.92	0.37	0.45	0.81	ODT
OLUS-04ST	48.45	42.15	*---	0.52	0.87	ODT
OLUS-03	879	835	0.25	0.09	0.95	ODT

(ODT – oil-down-to system)

Well OLUS–03 (Sand A)

The petrophysical evaluation of the reservoir interval within Well OLUS-03 of Sand A reveals significant reservoir quality and hydrocarbon potential, as detailed in Tables 4 and 5. Figure 6 displays the Volume of Shale calculation for Sand A in OLUS-03, where the gross sand thickness is 43.11 ft, with a net sand of 34.92 ft, indicating a substantial presence of clean, sand-dominated lithology. A net-to-gross (NTG) ratio of 0.81 further supports high reservoir quality, reflecting continuity and sand development. As shown in Table 5, the average porosity of 0.37 signifies well-developed pore spaces capable of storing substantial hydrocarbons. Figure 7 presents the Pickett plot used in calculating water saturation in OLUS-03; the green cluster of points shows a negative correlation: as porosity decreases, resistivity increases. This is typical reservoir behaviour. The linear trend (red line through red square points) represents the best-fit line for water-bearing and hydrocarbon-bearing zones. The water saturation (Sw) was estimated at 0.45, with hydrocarbon saturation (Sh) at 0.55, confirming the presence of hydrocarbons in the pore space. Furthermore, bulk volume of water (BVW) values suggest that formation water occupies a small part of the rock volume, supporting hydrocarbon productivity. These parameters characterise the reservoir as an oil-down-to (ODT) system, indicating a hydrocarbon-bearing formation with potential for commercial exploitation.

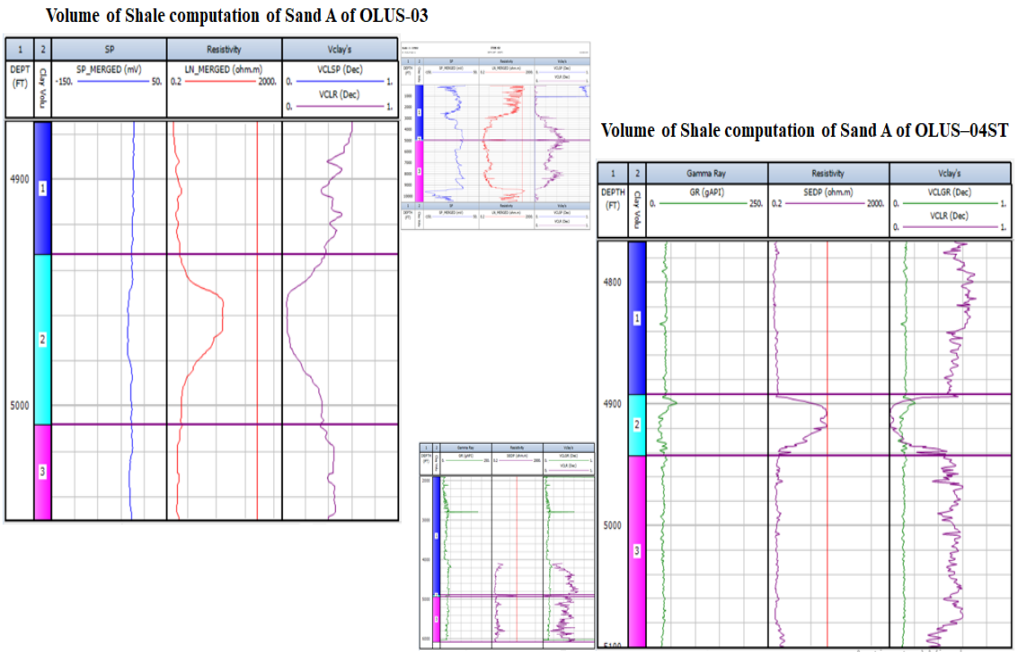


Figure 6: Volume of shale computation of Sand A within OLUS–03 and OLUS–04ST

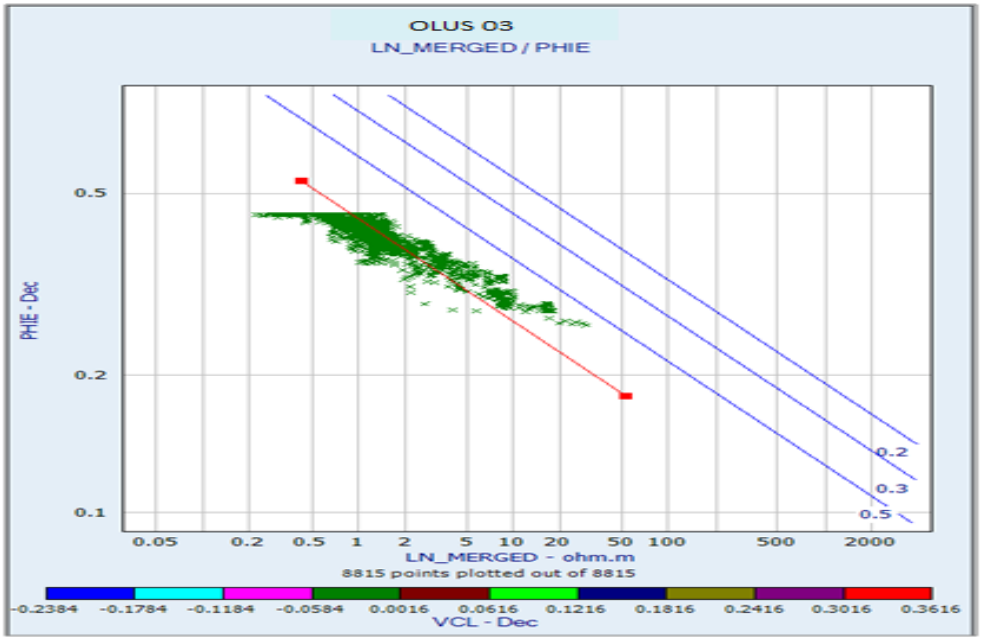


Figure 7: Pickett plot used in the determination of water saturation in OLUS-03 well

Well OLUS-04ST (Sand A)

The petrophysical assessment of Well OLUS-04ST within Sand A shows excellent reservoir properties and favourable hydrocarbon potential. As shown in Table 5 above, the gross sand and the net pay thicknesses are 48.45 ft and 42.15 ft, respectively. Figure 8 shows the well correlation of sand A as seen in both OLUS-04ST and OLUS-03 Wells. This direct correspondence indicates that the entire sand interval is productive and hydrocarbon-bearing. The high net-to-gross (NTG) ratio of 0.87 reflects strong sand development and lateral continuity, highlighting the reservoir's quality and effectiveness in storing and flowing hydrocarbons. Figure 9 shows the Pickett plot used in the calculation of water saturation in OLUS-04ST, where water saturation (Sw) is 0.52, while hydrocarbon saturation (Sh) is 0.48. The formation is characterised as oil-down-to, confirming the presence of hydrocarbons throughout the entire pay zone and indicating a potentially productive reservoir unit.

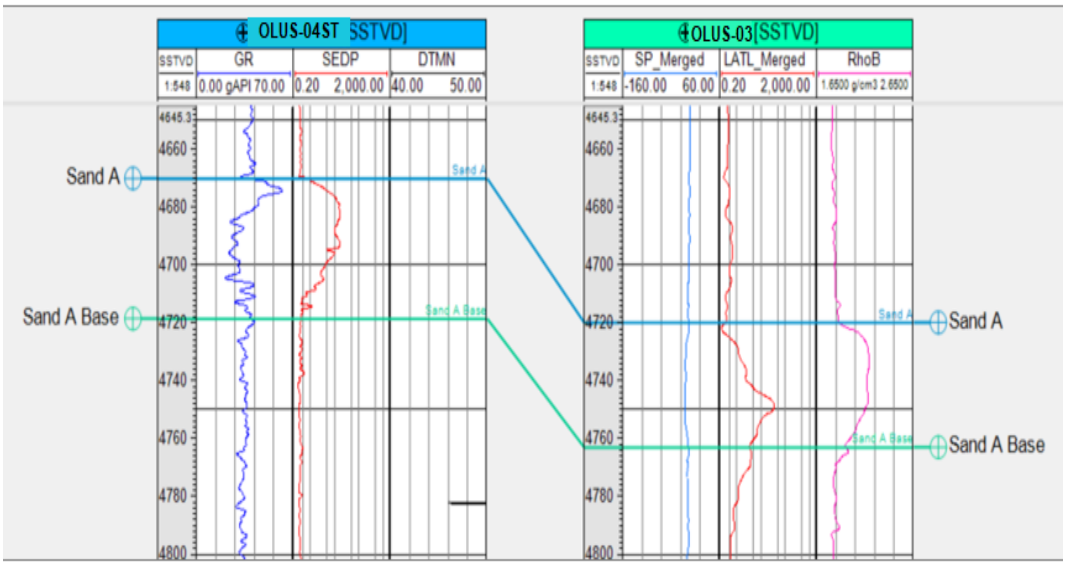


Figure 8: Well Correlation between Sand A as seen in both OLUS-04ST and OLUS-03 Wells

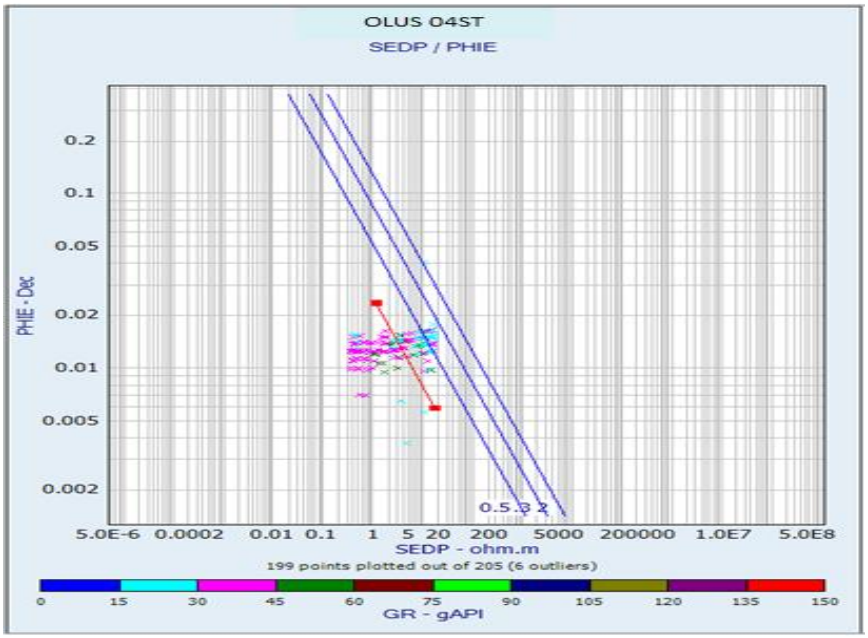


Figure 9: Pickett plot used in the determination of water saturation in OLUS-04ST well

Well OLUS–03 (Sand B)

The petrophysical analysis of Well OLUS-03 for Sand B indicates a high-quality reservoir with significant hydrocarbon potential. The gross sand and net pay sand measure 879 ft and 835 ft respectively, with a net-to-gross (NTG) ratio of 95%, reflecting excellent sand development and minimal shale presence (Table 5). Figure 10 illustrates the well properties of Sand B as observed in OLUS–03 only. Water saturation is very low at 0.09, while hydrocarbon saturation is as high as 0.91, confirming a predominantly hydrocarbon-filled pore system. The bulk volume of water (BVW) is also very low at 0.0225, suggesting efficient hydrocarbon displacement and minimal irreducible water content. These petrophysical features strongly indicate that the reservoir is highly porous and of exceptional quality, with an oil-down-to (ODT) contact, reinforcing its commercial viability and strong potential for productive development.

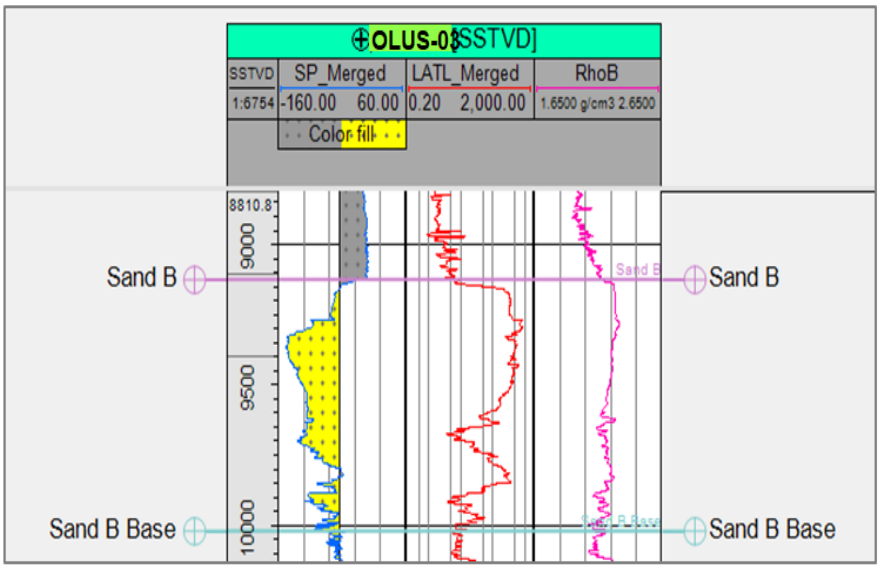


Figure 10: Well properties of Sand B as seen in OLUS–03 only

Discussion

Regionally, the Base of the Benin Formation is consistently recognized across the three wells, serving as a dependable stratigraphic marker and providing strong regional correlation control. Beneath this boundary, two significant sandstone packages have been identified in OLUS-03: Sand A and Sand B, with Sand A also traceable into OLUS-04ST (Figure 11).

Sand A shows clear lateral correlation between OLUS-03 and OLUS-04ST, with comparable thicknesses and similar log motifs, supporting the interpretation of a laterally extensive depositional unit, likely formed in a regionally persistent sedimentary environment such as a shoreface, delta-front, or sheet sand. However, its absence in OLUS-02 could be attributed to facies variations, structural displacement (faulting), or erosional truncation, suggesting local heterogeneity within the reservoir framework.

On the other hand, Sand B is present only in OLUS-03 and absent in both OLUS-02 and OLUS-04ST. This restricted distribution implies a more localized depositional system such as a channel fill, lobe, or isolated bar, or possibly removal by erosion in the other wells. The lack of lateral persistence reduces its regional significance, making it more of a secondary reservoir target.

Vertically, in OLUS-03, Sand A and Sand B are separated by intervening shale intervals, indicating limited vertical connectivity and representing distinct depositional episodes. These shale layers act as effective intra-reservoir seals, thereby compartmentalizing fluid flow. Importantly, the log responses (low gamma ray, high resistivity, and good density-neutron separation) confirm the clean and porous nature of both Sand A and Sand B, underscoring their potential as reservoir-quality intervals with strong hydrocarbon storage and flow characteristics.

The results of this study reveal the occurrence of high-quality sandstone reservoirs characterized by excellent geological properties and favorable production potential. The calculated Net-to-Gross (NTG) ratios, which range between 0.81 and 0.95, indicate that these reservoirs are predominantly composed of clean sand bodies with only minor shale intercalations. Such high NTG values reflect enhanced reservoir quality, as clean sands provide superior pore connectivity and minimize flow restrictions, thereby improving both storage capacity and fluid mobility. Porosity measurements, particularly from the OLUS-03 Well, confirm the preservation of excellent pore spaces, suggesting minimal diagenetic reduction and strong potential for long-term storage. Furthermore, the combination of low water saturation (Sw) and high hydrocarbon saturation (Sh) underscores the efficiency of these sandstones in hydrocarbon accumulation. This balance reflects favorable trapping conditions and reduced formation water presence, which directly enhances hydrocarbon deliverability.

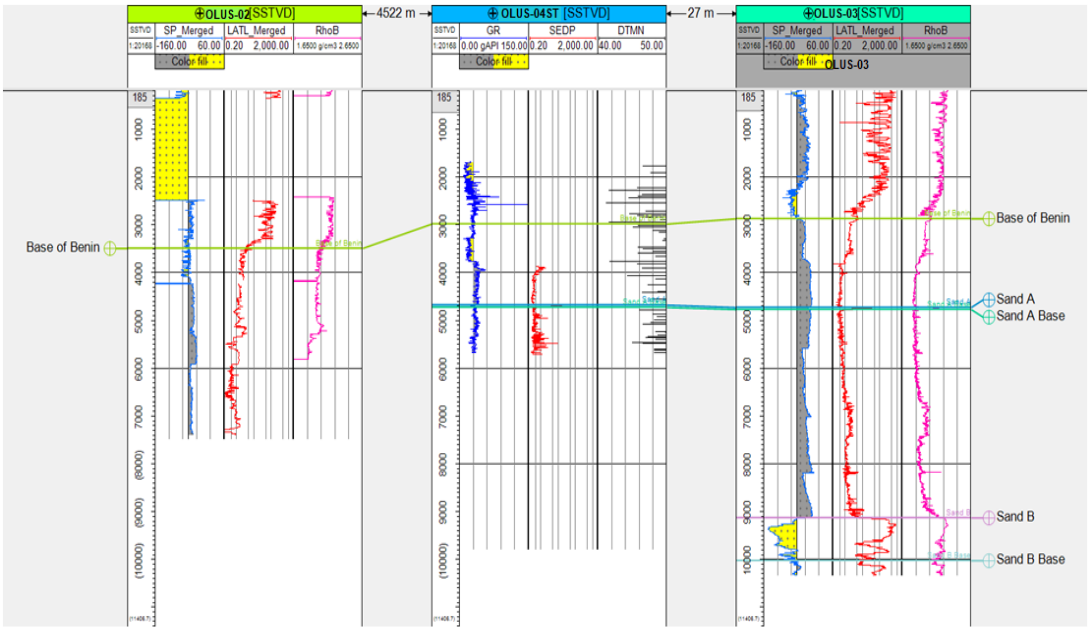


Figure 11: Well Correlation across the wells

The petrophysical results carry significant implications for reserve estimation within the Calabar Flank. The combination of favorable net-to-gross (NTG) ratios, high porosity values, and low bulk volume of water (BVW) indicates that the reservoirs have low irreducible water saturation and, consequently, a high proportion of movable hydrocarbons. This enhances the potential for efficient hydrocarbon recovery and increases confidence in the quality of the reservoirs. Furthermore, the classification of all identified reservoir intervals as oil-down-to (ODT) systems suggests the presence of laterally continuous oil columns across the field. This lateral continuity is particularly important for volumetric reserve estimation, as it minimizes uncertainties associated with reservoir compartmentalization and strengthens the reliability of hydrocarbon-in-place calculations.

The hydrocarbon significance of the two identified sand bodies can be summarized as follows: Sand A demonstrates excellent reservoir potential, primarily due to its lateral continuity, significant thickness, and clean log signatures, which collectively indicate substantial porosity and permeability. These characteristics make it a prime exploration and production target, as it likely forms a laterally extensive reservoir unit capable of supporting sustained hydrocarbon accumulation and flow. Its regional continuity also enhances confidence in volumetric reserve estimates and reduces risks associated with reservoir compartmentalization.

Sand B, on the other hand, exhibits more localized development and limited lateral continuity. While it also hosts hydrocarbons, its productivity will depend heavily on detailed structural and stratigraphic mapping to define its distribution and connectivity. Given its characteristics, Sand B may function as a stratigraphic trap or localized reservoir, rather than a regionally extensive accumulation. This makes it a secondary exploration target, requiring cautious appraisal and tailored development strategies.

The presence of interbedded shale units between the sands provides an effective seal mechanism, reducing vertical communication and creating conditions for stacked reservoir systems. This stratigraphic architecture increases the overall prospectivity of the interval, offering opportunities for multiple hydrocarbon-charged reservoirs within the same

stratigraphic succession. These findings highlight that the Calabar Flank reservoirs offer not only strong production potential but also favorable conditions for cost-effective and scalable development planning.

However, despite these promising findings within this study, several limitations merits acknowledgment. First of all, this study relied on data from a limited number of wells, which may not fully capture lateral heterogeneity across the region of Calabar Flank. Secondly, the log-derived petrophysical parameters are sensitive to calibration errors, tool limitations, and assumptions in fluid and matrix properties. Lastly, the absence of core data, seismic integration, and pressure information restricts the ability to validate porosity, permeability, and saturation estimates, in which addressing these limitations through integrated seismic-petrophysical analysis and core calibration would enhance the accuracy of reserve estimation and provide deeper insights into Calabar Flank's reservoir architecture.

Conclusion

In conclusion, this study provides a petrophysical evaluation of hydrocarbon reservoirs in the Calabar Flank situated in the south-eastern part of Nigeria, demonstrating the presence of prolific sandstone units with exceptional reservoir quality. The results of the petrophysical analysis of hydrocarbon reservoirs in the region reveal the presence of extensive, high-quality sandstone formations characterized by high net-to-gross ratios up to 0.95, excellent porosity, low water saturation, and high hydrocarbon saturation with minimal shale intercalations. The alignment of gross sand with gross pay, and net sand with net pay, across all wells suggests that the entire sand units are hydrocarbon-bearing and meet reservoir criteria. The consistently low bulk volume of water and the classification of the zones as oil-down-to (ODT) indicate a favourable hydrocarbon distribution and strong production potential. These findings confirm that the Calabar Flank hosts prolific reservoir systems with significant reserves, making it a viable target for further exploration and development. The oil-down-to (ODT) character of all analysed intervals further confirms lateral continuity and reservoir connectivity, reducing compartmentalization risk and enhancing commercial potential. Compared with regional and global analogues, the Calabar Flank ranks among promising Cretaceous reservoirs, positioned as a frontier zone with significant hydrocarbon resources.

The findings in this study have direct contributions for reserves estimation and field exploration planning within Calabar Flank, as favourable petrophysical properties support reliable volumetric calculations, indicating substantial hydrocarbons in place and improved recovery potential. Beyond filling a major knowledge gap in the quantitative assessment of the Calabar Flank, this study provides practical insights to guide exploration strategies in Nigeria's inland basins. While the limited well coverage and absence of core and seismic integration introduce some uncertainties, the results in this study establish a solid foundation for future studies within the region. Ultimately, the Calabar Flank emerges as a viable region for sustained exploration and field development with the potential to contribute meaningfully to Nigeria's energy diversification and long-term resource.

References

Adeleye D.R. & Fayose F.A. (1978). Stratigraphy of the type section of Awi formation, Odukpani area, southern Nigeria. Journal of Mining Geology 15:33–57

Ahammod, S., Hai, M. A., Islam, M. R. & Abu, S. M. (2014). Petro-physical analysis of reservoir rock of Fenchuganj Gas Field (Well# 03) using wireline log. *American Journal of Engineering Research (AJER), 3*(8), 37-48.

Ahmed, L., Farah, A. & Ibrahim, H. (2024). Predicting Reservoir or Non-Reservoir Formations by Calculating Permeability and Porosity in an Iraqi Oil Field. *Journal of Chemical and Petroleum Engineering*, *2024*(1), 115–129. https:// doi.org/10.22059/ jchpe.2024.367201.1459

Aka, M. U., Effiong, C. I. & Akpan, D. N. (2022). Assessment of Nkporo Shales in Calabar Flank to Ascertain its Hydrocarbon Potentials, South-South, Nigeria. *J Geol Geophys*, *11*, 1027.

Al Fatta Abdullah, M., Islam, S. & Farhaduzzaman, M. (2018). Petrophysical analysis of sylhet gas field using well logs and associated data from Well Sylhet, Bangladesh. *Int. J. Pet. Petrochem. Eng*, *4*(1), 55-69.

Al-Baldawi B. A. (2014). Petrophysical evaluation study of Khasib Formation in Amara oil field, South Eastern Iraq. *Arabian Journal of Geosciences*, *8*(4), 2051–2059. https://doi.org/10.1007/s12517-014-1371-5

Al-Rubaye, A., Al-Yaseri, A., Ali, M. & Ben Mahmud, H. (2021). Characterization and analysis of naturally fractured gas reservoirs based on stimulated reservoir volume and petro-physical parameters. *Journal of Petroleum Exploration and Production Technology*, *11*(2), 639–649. https://doi.org/10.1007/s13202-020-01081-2

Amigun, J. O. & Odole, O. A. (2013). Petrophysical properties evaluation for reservoir characterisation of Seyi oil field (Niger-Delta). *International Journal of innovation and applied studies*, *3*(3), 756-773.

André, D. N., Joseph, N. I. & Sunday, I. S. (2022). Hydrocarbon reservoir petrophysical characterization with statistical simulations: a case study from the Gulf of Guinea. *International Journal of Scientific Research and Engineering Development*, *5*(2).

Anyiam, O. A., Andrew, P. J. & Ikenna Christopher Okwara. (2017). Assessment of the heterogeneity and petrophysical evaluation of reservoirs in the "Akbar Field", Niger Delta, Nigeria. *Journal of Petroleum Exploration and Production Technology*, *7*(4), 1035–1050. https://doi.org/10.1007/s13202-017-0361-z

Asquith G.B. & Krygowski D. (2004) Basic well log analysis, 2nd edition: AAPG methods in exploration series 16. The American Association of Petroleum Geologists, Oklahoma, 244p

Bate, B. B., Boboye, O. A., Fozao, K. F., Ndip, E. A. & Anene, N. O. (2022). Petrophysical characterization and 3D seismic interpretation of reservoirs in the Baris Field, onshore Niger Delta Basin, Nigeria. *Energy Geoscience*, *4*(1), 103–116. https://doi.org/10.1016/j.engeos.2022.02.001

Boboye, O. A. & Okon, E. E. (2014). Sedimentological and geochemical characterization of the Cretaceous strata of Calabar Flank, southeastern Nigeria. *Journal of African Earth Sciences*, *99*, 427–441. https://doi.org/10.1016/j.jafrearsci.2014.04.035

Chikiban B., Kamel, M. H., Mabrouk, W. M. & Metwally, A. (2022). Petrophysical characterization and formation evaluation of sandstone reservoir: Case study from Shahd field, Western Desert, Egypt. *Contributions to Geophysics and Geodesy*, *52*(3), 443–466. https://journal.geo.sav.sk/cgg/article/view/431

d'Almeida, G. A. F., Kaki, C. and Adeoye, J. A. (2016). Benin and Western Nigeria Offshore Basins: A Stratigraphic Nomenclature Comparison. *International Journal of Geosciences*, *07*(02), 177–188. https://doi.org/10.4236/ijg.2016.72014

Edet, J.J. & Nyong, E.E., (1993). Depositional environments, sea level history and paleobiogeography of the Late Campanian to Maastrichtian on the Calabar Flank, S.E. Nigeria. Paleoclimatology, Paleoecology, Vol. 102, pp 161 – 175.

Ekhalialu O.M., Ukpong A.J., Ogidi A.O., Asi M.O. & Osung W.E. (2016). Stratigraphic Characterization of Parts of the Awi Formation, Calabar Flank, South Eastern Nigeria. International Journal of Current Trends in Engineering & Research 2(11):50-70

Ekpo, B. O., Essien, N., Fubara, E. P., Ibok, U. J., Ukpabio, E. J. & Wehner, H. (2013). Petroleum geochemistry of Cretaceous outcrops from the Calabar Flank, southeastern Nigeria. *Marine and Petroleum Geology*, *48*, 171–185. https://doi.org/ 10.1016/ j.marpetgeo.2013.08.011

Ekpo, B. O., Ibok, U. J., Essien, N. & Wehner, H. (2012). Geochemistry and organic petrography of Cretaceous sediments of the Calabar Flank, southeastern, Nigeria. *Marine and Petroleum Geology*, *35*(1), 252–268. https://doi.org/10.1016/j.marpetgeo.2012.03.010

Ekwok, S. E., Akpan, A. E. & Ebong, E. D. (2021). Assessment of crustal structures by gravity and magnetic methods in the Calabar Flank and adjoining areas of Southeastern Nigeria—a case study. *Arabian Journal of Geosciences*, *14*(4). https://doi.org/10.1007/s12517-021-06696-1

Essien, N.U., Ukpabio, E.J., Nyong, E.E. & Ibe, K.A., (2005). Preliminary organic geochemical appraisal of Cretaceous rock unit in the Calabar Flank, Southern Nigeria. Journal of Mining and Geology, Vol. 41 (2), pp 181 – 191.

Essien, U., Akankpo A. & Agbasi O. (2017). Evaluation of Reservoir's Petrophysical Parameters, Niger Delta, Nigeria. *International Journal of Advanced Geosciences*, *5*(1), 19–19. https://doi.org/10.14419/ijag.v5i1.7456

Harry, T. A., Etim, I. U. & Etim, C. E. (2022). Sedimentology And Palynology Models Of Sedimentary Sections Along Lemna Section Of The Benin Formation, Cross River-Southern Nigeria. *Pakistan Journal of Geology (PJG)*, *6*(1), 24-28.

Ilori, A. O. (2016). Occurrence of shale soils along the Calabar-Itu highway, Southeastern Nigeria and their implication for the subgrade construction. *SpringerPlus*, *5*(1). https://doi.org/10.1186/s40064-016-1822-4

Isaac, E. E., Nnoyelu, O. & Esther, I. A. (2024). *Integrated Analysis of Gravity and Geoidal Anomalies for Understanding Crustal Deformation and Tectonic Processes in the Calabar Flank, Nigeria*. https://www.allmultidisciplinaryjournal.com/uploads/archives/20240917190502_E-24-68.1.pdf

Larionov, V. V. (1969). Borehole radiometry. *Nedra, Moscow*, *127*, 813

Maju-Oyovwikowhe E.G. & Ighodaro E.J. (2023). Petrophysical properties and volume estimation of hydrocarbon resources in x field, onshore niger delta: A reservoir characterization study. *Scientia Africana*, *22*(1), 151–174. https://doi.org/10.4314/sa.v22i1.14

Mheluka, J. M. & Mulibo, G. D. (2018). Petrophysical Analysis of the Mpera well in the Exploration Block 7, Offshore Tanzania: Implication on Hydrocarbon Reservoir Rock Potential. *Open Journal of Geology*, *08*(08), 803–818. https:// doi.org/10.4236 /ojg.2018.88047

Murat, R. C. (1972). Stratigraphy and Palaeogeography of the Cretaceous and Low Tertiary in southern Nigeria: In African geology ((ed. Dessauvajie. T. F. J., and Whiteman. A. J.) (University Ibadan Press, Ibadan, 1972). pp. 251-266.

Muther, T., Qureshi, H. A., Syed, F. I., Aziz, H., Siyal, A., Dahaghi, A. K. & Negahban, S. (2021). Unconventional hydrocarbon resources: geological statistics, petrophysical characterization, and field development strategies. *Journal of Petroleum Exploration and Production Technology*. https://doi.org/10.1007/s13202-021-01404-x

Nton, M. E. & Adeyemi, M. O. (2021). Evaluation of Hydrocarbon Reserve in AD Field, Offshore Niger Delta. *Open Journal of Geology*, *11*(05), 155–174. https:// doi.org/10 .4236/ojg.2021.115009

Nton, M. E., Akpan, O. S. & Adamolekun, O. J. (2018). Geochemistry of Ekenkpon and Nkporo shales, Calabar flank, SE Nigeria: implications for provenance, transportation history and depositional environment. *Global Journal of Geological Sciences*, *16*(1), 63–63. https://doi.org/10.4314/gjgs.v16i1.7

Nwaezeapu, V. C., Ezenwaka, K. C. & Ede, T. A. (2019). Evaluation of hydrocarbon reserves using integrated petrophysical analysis and seismic interpretation: A case study of TIM field at southwestern offshore Niger Delta oil Province, Nigeria. *Egyptian Journal of Petroleum*, *28*(3), 273–280. https://doi.org/10.1016/j.ejpe.2019.06.002

Nyong, E.E. & Ramanathan, R.M. (1985). A record of oxygen-deficient paleoenvironments in the Cretaceous of the Calabar Flank, SE Nigeria. J. Afr. Earth Sc. 3 (4), 455–460.

Odumodu, C. F. (2012). Temperatures and Geothermal gradient fields in the Calabar Flank and parts of the Niger Delta, Nigeria. *Petroleum Technology Development Journal*, *2*(2), 1-15.

Ogidi, A. O., Essien, N. U., Okon, E. E., Nton, M. E. & A, J. C. (2021). Evaluation of the Shale Gas Potentials of Ekenkpon Shale, Calabar Flank, Southeastern Nigeria. *NAPE Bulletin*, *30*(1), 55–69. https://www.researchgate.net/publication/357854115_Evaluation_of_the_Shale_Gas_Potentials_of_Ekenkpon_Shale_Calabar_Flank_Southeastern_Nigeria

Okiwelu, A., Okwueze, C., Okereke, C. S. & Osazuwa, I. (2010). Crustal structure and tectonics of the Calabar Flank, West Africa, based on residual gravity interpretation. *European journal of scientific research*, *42*(2), 195-203.

Okon, E. E. & Ojong, R. A. (2019). Paleoenvironmental analysis and its significance in sedimentology: case study of the conglomerate facies of the Awi Formation, Calabar Flank, Southeast Nigeria. *Advances and trends in physical science research*, *2*.

Olayiwola M., Durugbo, E., Fajemila O., Oyebanjo O., Aderogba A., Olaleye-Otunla O., & Aderanti A. (2023). Paleoecology, Paleoenvironment, and Petroleum Potential of middle-upper Cretaceous Calabar Flank Sediments, Southeastern Nigeria. *Advances in Science, Technology & Innovation/Advances in Science, Technology & Innovation*, 25–29. https://doi.org/10.1007/978-3-031-43222-4_6

Oluwajana, O. A., & Ehinola, O. A. (2018). Potential shale resource plays in southeastern Nigeria: petroleum system modelling and microfabric perspectives. *Journal of African Earth Sciences*, *138*, 247-257.

Omigie J.I. & Alaminiokuma G.I. (2020). Petrophysical Evaluation Of Reservoirs For Hydrocarbon Reserve Estimation In Eastern Central Swamp Depobelt, Niger Delta. Malaysian Journal of Geosciences, 4(2): 57- 63.

Onita, F. B., Ebeh, C. O. & Iriogbe, H. O. (2023). Advancing quantitative interpretation petrophysics: Integrating seismic petrophysics for enhanced subsurface characterization. *Engineering Science & Technology Journal*, *4*(6), 617-36.

Oyeyemi, K. D., Olowokere, M. T. & Aizebeokhai, A. P. (2017). Hydrocarbon resource evaluation using combined petrophysical analysis and seismically derived reservoir characterization, offshore Niger Delta. *Journal of Petroleum Exploration and Production Technology*, *8*(1), 99–115. https://doi.org/10.1007/s13202-017-0391-6

Paul, S. S., Okwueze E. E. & Udo, K. I. (2018). Petrophysical Analysis of Well Logs for the Estimation of Oil Reserves in Southern Niger Delta. *International Journal of Advanced Geosciences*, *6*(1), 145–145. https://doi.org/10.14419/ijag.v6i1.11815

Petters S.W., Nyong E.E., Akpan E.B. & Essien N.U. (1995). Lithostratigraphic revision for the Calabar Flank, S. E. Nigeria. Proceedings of the 31st Anniversary conference of Nigeria Mining and Geosciences Society, Calabar

Ramanathan R.M. & Kumaran KP..N (1981). Age and paleoecology of M-1 well in Calabar Flank, southeastern Nigeria. Journal of Mining and Geology 18:163-171

Reijers T.J.A (1998). The Mfamosing limestone in South-East Nigeria: Outcrop Subsurface correlation and reservoir development. J. Petroleum Geol. 10: 238 – 294.

Reijers T.J.A. & Petters, S. W. (1987). Depositional Environments and Diagenesis of Albian Carbonates on The Calabar Flank, Se Nigeria. *Journal of Petroleum Geology*, *10*(3), 283–294. https://doi.org/10.1111/j.1747-5457.1987.tb00947.x

Reijers, T. J. & Petters S. W. (1987). Depositional environment of Albian carbonates in the Calabar Flank South Eastern Nigeria. Nigeria Journal of Petroleum Geology, 10.283 - 294.

Reyment, R. A. (1965). Aspects of the geology of Nigeria: the stratigraphy of the Cretaceous and Cenozoic deposits. University of Ibadan Press, Ibadan, Nigeria, 145p.

Saadu, Y. K. & 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), 531–539. https://doi.org/10.1016/j.ejpe.2017.08.004

Sadeq D., Almomen, A., Hamad, H. & Usama Alameedy. (2024). Exploring the Impact of Petrophysical Uncertainties on Recoverable Reserves: A Case Study. *Iraqi Geological Journal*, *57*(1C), 47–61. https://doi.org/10.46717/igj.57.1c.4ms-2024-3-16

Selema, S. B., Ideozu, R. U. & Acra, E. J. (2023). Mid-Cretaceous Subsurface Carbonate Deposit And Reservoir Development Of The Mfamosing Limestone Calabar Flank. *International Journal of Research -GRANTHAALAYAH*, *11*(5), 112–128. https://doi.org/ 10.29121/ granthaalayah.v11.i5.2023.5175

Shah, S., Khan, H. R., Rahman, A., Islam, R., Ahmed, S. I., Molla, M. I. & Butt, S. (2021). Petrophysical evaluation of well log data for reservoir characterization in Titas gas field, Bangladesh. *Journal of Natural Gas Science and Engineering*, 104129. https://doi.org/10.1016/j.jngse.2021.104129

Short, K.C. & Stauble, A.J., (1967). Geology of the Niger Delta. AAPG Bulletin, 9(51), 761-779.

Temple, O. A., Morod, I. M., Godwin, A., Benjamin, O. O. & Ojikutu, L. T. (2024). Geochemistry Of Awi Sandstone, Calabar Flank, Southeastern (Se) Nigeria: Constraints On The Metal Enrichment, Provenance, And Tectonic Setting. *Global Journal of Geological Sciences*, *22*(1), 79–112. https://doi.org/10.4314/gjgs.v22i1.7

Udo, I. G., Udofia, P. A., Etukudo, N. J., & Adesina, D. A. (2023). Paleoenvironmental interpretation of the exposed section of the Benin Formation in southeastern part of the Niger Delta Basin, Nigeria: A pebble morphometric approach. *IOSR Journal of Applied Geology and Geophysics*, *11*, 12-19.

Whiteman, A.J. (1982). Nigeria: its Petroleum Geology, Resources and Potential. I. Graham and Trotman Ltd, London, p. 166.