RESERVOIR CHARACTERIZATION IN ALERO FIELD, NIGER DELTA, NIGERIA.

BY

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A PROJECT WORK SUBMITTED TO THE DEPARTMENT OF GEOLOGY, FACULTY OF PHYSICAL SCIENCES, UNIVERSITY OF BENIN, IN PARTIAL FULFILMENT OF THE REQUIREMENT FOR THE AWARD OF A BACHELOR OF SCIENCE DEGREE (B.Sc), GEOLOGY.

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CERTIFICATION

This is to certify that Ezekiel Onyedikachi OKPALAEKE, with mat no. PSC2008258, carried out this project work which was submitted and approved by the department of Geology, in fulfilment of the degree of Bachelor of science (B.Sc.), Geology.

Dr. S.A. Salami ________________ ________________
(Head of Department) (signature) Date

Dr. A. Ogbamikhumi ________________
____
(Supervisor) (signature)
Date

DEDICATION

I dedicate this project work to the Almighty God, whose grace, mercies, wisdom and divine guidance have been my source of strength throughout my academic journey.

I also dedicate this work to my dearly beloved parents, Mr. and Mrs. Okpalaeke, for their unwavering support, encouragement, and sacrifices that have shaped my path.

To my siblings, I am thankful for your constant motivation and love throughout, which have been a source of inspiration for me. Your belief in me has made this accomplishment possible.

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I want to specially thank the Lord Almighty for His enduring and persistent grace over my life; Who specially saw me through my academic journey in the attainment of a B.Sc. degree. Honestly, His loving kindness and tender mercies came through for me till the very end of this phase.

Special thanks to my amiable supervisor, Dr. A. Ogbamikhumi, for his help and guidance towards the success of this work. I appreciate the head of department, Dr. S.A. Salami for his effort and contribution to the attainment of this degree. I also specially appreciate all the staff and lecturers of the department; Dr. (Mrs). O. Odokuma-Alonge, Dr. (Mrs). O. Andre-Obayanju, Dr. N.S. Igbinigie, Dr. (Mrs) E. G. Maju-Oyovwikowhe and Others.

I won’t fail to express my gratitude to my supportive parents Mr. and Mrs. Okpalaeke whose love, care, support and encouraging kept me on the go. I also express my gratitude to my siblings, other members of my family and friends who contributed in making this work and my entire academic journey a success.

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ABSTRACT

This study attempts to access the quality, spatial variation and economic viability of A and C reservoirs across eight wells in the Alero Field. Suites of wireline well log data for the wells of the Alero Field were evaluated to characterize the reservoirs. From the quantitative and qualitative analyses carried out, it was revealed that reservoir A has the following petrophysical characteristics across the wells; Gross thickness 14.85m to 193.01m, shale volume 16% to 28%; total porosity: 31% to 34%; effective porosity: 25% to 29%; permeability: 9962.25mD to 12912.90mD; water saturation: 7% to 24%, while for reservoir C across the wells; shale volume 10% to 36%%; total porosity: 28% to 33%; effective porosity: 21% to 29%; permeability: 10174.20mD to 12498.70mD; water saturation: 5% to 59%.

The results show both reservoirs to exhibit favourable properties across the wells, including moderate to high net-to-gross (NTG) ratios, effective porosity, high hydrocarbon saturation, and good permeability. However, variations in shale content (VSh), water saturation, as well as pay zone thickness across the wells suggest spatial heterogeneity in reservoir quality.

Overall, reservoir A is found to be a more promising candidate for oil production, showing better permeability (10174.20mD to 12498.70mD) and overall hydrocarbon saturation (75% to 93%).

CHAPTER ONE

1.0 INTRODUCTION

1.1 GENERAL INTRODUCTION

Petroleum is a naturally occurring mixture of solid, liquid, and gaseous hydrocarbons, commonly yellowish-black in color. While petroleum is generally regarded as an organic material derived from the decomposition of ancient biological matter, some theories support an inorganic origin. Being less dense than water, petroleum tends to migrate from source rock beds into permeable formations such as sandstone and limestone, where it accumulates until trapped by impermeable barriers like shale or dense limestone. Geological processes, including folding, faulting, and erosion, contribute to the formation of petroleum reservoirs. Petroleum may exist in various phases: gas, liquid (crude oil), or semi-solid forms (bitumen, tar, pitch, or asphalt). When these phases occur together, gas typically overlays liquid petroleum, which, in turn, rests above the more solid phase. The recognition of petroleum's diverse applications has driven advancements in exploration and extraction technologies, shaping the global energy industry.

A comprehensive understanding of reservoir rock properties is crucial in evaluating reservoir quality, estimating hydrocarbon volume, optimizing well placement, and reducing uncertainty in hydrocarbon production. Reservoir characterization involves assessing intrinsic properties such as thickness, net-to-gross ratio, pore fluid distribution, porosity, permeability, water saturation, and volumetric reserves. Well log evaluation is a fundamental technique in reservoir characterization, providing geoscientists with critical insights into the physical properties, structure, and fluid content of the reservoir.

The Niger Delta spans approximately 75,000 km^2 and contains clastic sedimentary deposits reaching thicknesses of up to 12,000 meters (Weber, 1987). It is considered one of the most prolific petroleum-producing tertiary deltas globally, accounting for approximately 5% of the world's oil and gas reserves. Sedimentation in the Niger Delta depobelts is controlled by sediment supply and the availability of accommodation space created by the subsidence of underlying basement rocks. The dominant structural features of the Niger Delta are growth faults, which result from the contemporaneous deformation of deltaic sediments. These faults often displace parts of the Agbada Formation, creating structural traps for hydrocarbon accumulation. Reservoir rocks in the Niger Delta primarily consist of sandstones and unconsolidated sands, predominantly of Eocene to Pliocene age, with thicknesses ranging from less than 15 meters to approximately 45 meters (Evamy, 1978). The geometry and quality of these reservoirs are influenced by listric faults, with reservoir thickness increasing towards the downthrown fault blocks (Weber, 1975).

To minimize resource wastage and reduce uncertainty—two significant challenges in the oil and gas industry—accurate reservoir evaluation and characterization are essential. This process involves determining petrophysical properties, including porosity, permeability, water saturation, shale volume, and hydrocarbon saturation, as well as estimating recoverable reserves.

This study aims to utilize and analyze well log data for reservoir characterization to assess the hydrocarbon storage potential of the Niger Delta reservoirs.

1.2 BACKGROUND THEORY

1.2.1 WELL LOGGING AND PETROPHYSICS

Petrophysics is a field that finds great application in the study and evaluation of reservoirs for hydrocarbon industries. Some of the major properties studied in this field of study include lithology, total and effective porosity, water saturation, permeability, density, shale volume and net-to-gross ratio. A major aspect of petrophysics involves the careful evaluation of these rock properties, by acquiring well log measurements from available well logs.

Well log evaluation is basically the arrangement of specific characteristics of a formation in a well against depth. Key information about the formation is revealed in the drilled hole and these are recorded against depth on logs. Logs unlike seismic sections (which provides spatial resolution) provide good information about the vertical resolution of a particular portion of the survey area. Log analysis comes in very handy in delineation of reservoirs and estimation of its properties (Mode and Anyiam, 2007). The log may be based on either geological Logs (i.e on visual inspection of ditch cuttings brought to the surface) or geophysical logs (on physical measurements made by measuring tools attached to a sonde, lowered into the hole). Logs are acquired from a well by lowering a sonde attached to a cable into the well bore, section after section with increasing depth. The the measuring tools attached to the sonde takes record of properties like gamma ray radiation, electrical conductivity/resistivity, nuclear or acoustic energy, after which the sonde is continuously raised from the bore bottom at a specific rate. The well record is taken when the sonde arrives at the top of the particular interval to be investigated.

The Formation fluid content, density, porosity, permeability, radioactivity and so on, are rock properties that affect logging and the types of logs to be obtained. Formation evaluation involves the comparison of different type of well logs, after which the properties of the rocks are established. Well logging is an indirect means of evaluating formations as it only reveals the properties of the rock, and directly its composition. Logging of well is carried out when drilling boreholes for oil and gas, minerals, groundwater, environmental investigation as well as geotechnical studies. Basically, well logs can be acquired in two major forms, which are:

a) Logging While Drilling
b) Wire Line Logging (open hole and cased hole)

Logging while drilling (LWD) or measurement while drilling (MWD) is a contemporary technique that allows the continuous collection of a well information at the surface. In the use of these logs, data is transmitted from the tools at the bottom of the drill string to the processors at the surface. On the other hand, wireline logging involves the lowering of the measuring tool (sonde) attached to a wireline into a well to take recordings across the well bore. There are many petrophysical logs in use today. For the purpose of this research work, a few will be discussed.

Some examples of petrophysical logs include:

a) Gamma ray log
b) Resistivity log
c) Density log
d) Neutron log

1.2.1a GAMMA RAY LOG

Radioactive elements naturally emit high-energy electromagnetic waves known as gamma rays. A gamma ray log measures the natural radioactivity of the rocks surrounding a borehole, primarily detecting isotopes of potassium, uranium, and thorium. These elements are most commonly found in shales, which originate from the weathering of preexisting igneous rocks. Gamma ray logs are primarily used to assess the shale or clay content within a formation. Since low-density formations like sandstones generally lack significant amounts of radioactive elements, clean sandstones exhibit low gamma ray readings—except in cases of radioactive sands. The gamma ray log is useful in evaluating the shale volume within a reservoir, detecting radioactive sands, and distinguishing lithologies. When combined with other well logs, it provides valuable insights into reservoir properties, aiding in hydrocarbon exploration and production.

1.2.1b RESISTIVITY LOG

The resistivity log measures variations in the electrical properties of the formation surrounding a wellbore. It is one of the fundamental principles on which the science of well logging was developed. Different materials have varying capacities to resist the flow of electric current, with resistivity being inversely related to conductivity.

Resistivity logs provide a key measurement for evaluating a reservoir’s fluid saturation. Since resistivity is influenced by fluid content, the log helps differentiate between fresh water, saltwater, and hydrocarbons within the formation. Hydrocarbons exhibit the highest resistivity, whereas saltwater has the lowest. Consequently, hydrocarbon-bearing zones appear as high-resistivity regions on the log, making resistivity logging an essential tool for fluid discrimination.

Additionally, resistivity logs help delineate areas with relatively high permeability. This is evident in the triple resistivity readings—MSFL (Micro Spherically Focused Log), LLS (Laterolog Shallow), and LLD (Laterolog Deep)—which are recorded in hydrocarbon-bearing permeable rocks. In permeable formations, drilling fluids infiltrate the rock, creating distinct zones around the wellbore. The resistivity values follow a characteristic pattern: MSFL records the flushed zone (where drilling mud filtrate has displaced formation fluids), LLS records the invaded zone, and LLD represents the uninvaded zone, where the original formation fluids remain.

1.2.1c DENSITY LOG

The density log is a porosity log that measures the bulk density of a formation. It plays a crucial role in identifying gas-bearing zones, particularly when cross-plotted with the neutron log. This is observed in the characteristic "balloon effect" that results from the combination of the two logs, where gas zones exhibit a distinct separation between neutron and density readings.

Density logs are also essential for determining the total porosity of a formation. Higher-density regions indicate more compacted formations with lower porosity, whereas lower-density regions correspond to less compacted formations with higher porosity. The density log is typically recorded on a scale ranging from 1.65 to 2.65 g/cm^3 or 1.85 to 2.85 g/cm^3, depending on the rock matrix.

The presence of fluids in a rock influences its bulk density, which represents the combined density of both the rock matrix and the fluid it contains. Denser fluids contribute to a higher bulk density. Consequently, the density of a formation decreases in the following order: water-bearing rocks have the highest density, followed by oil-bearing rocks, with gas-bearing rocks exhibiting the lowest density.

1.2.1d NEUTRON LOG

Just like the density log, the neutron log is also a porosity log; however, it specifically measures the hydrogen concentration within a formation. During neutron log recording, neutrons are emitted into the formation, targeting the hydrogen present in the pores of rocks. The hydrogen atoms slow down the neutron energy, and this attenuation is recorded by the sonde. This makes the neutron log a more effective tool for measuring porosity compared to the density log.

Since pores are filled with fluids, the hydrogen concentration is influenced by fluid type. Water and oil (both liquids) have similar hydrogen counts, whereas gas has a relatively lower neutron count. This property makes the neutron log highly effective for hydrocarbon fluid discrimination, distinguishing gas-bearing zones from oil zones. When used in conjunction with the density log, gas-bearing zones are identified by a "balloon effect," where the neutron-density readings exhibit significant separation due to the lower hydrogen content of gas. Conversely, the "shale effect" is observed as high neutron-density readings due to the presence of hydroxyl ions in shales, which contribute to higher hydrogen counts compared to sands.

The neutron and density logs also aid in lithology discrimination. The point where these two logs intersect indicates a change in lithology, while zones where they overlay each other suggest water-bearing formations. Consequently, combining neutron and density logs helps validate lithology interpretations made using gamma-ray logs.

1.3 AIM

To evaluate the petrophysical properties of prospective reservoirs in Alero field, characterize them and tell their qualities for hydrocarbon storage.

1.4 OBJECTIVES

1. To carry out well log evaluation
2. To identify reservoirs of interest across wells
3. Carry out petrophysical analysis on the reservoirs
4. To tell spatial variation of the reservoirs' properties
5. To determine the reservoir types and qualities
6. To give helpful suggestions for further studies

1.5 SCOPE OF STUDY

Reservoir property evaluation: petrophysical properties of the reservoir will be evaluated from well logs.

1.6 LOCATION OF STUDY FIELD

The study area is located within the shallow offshore depobelt of the Niger Delta Sedimentary Basin.

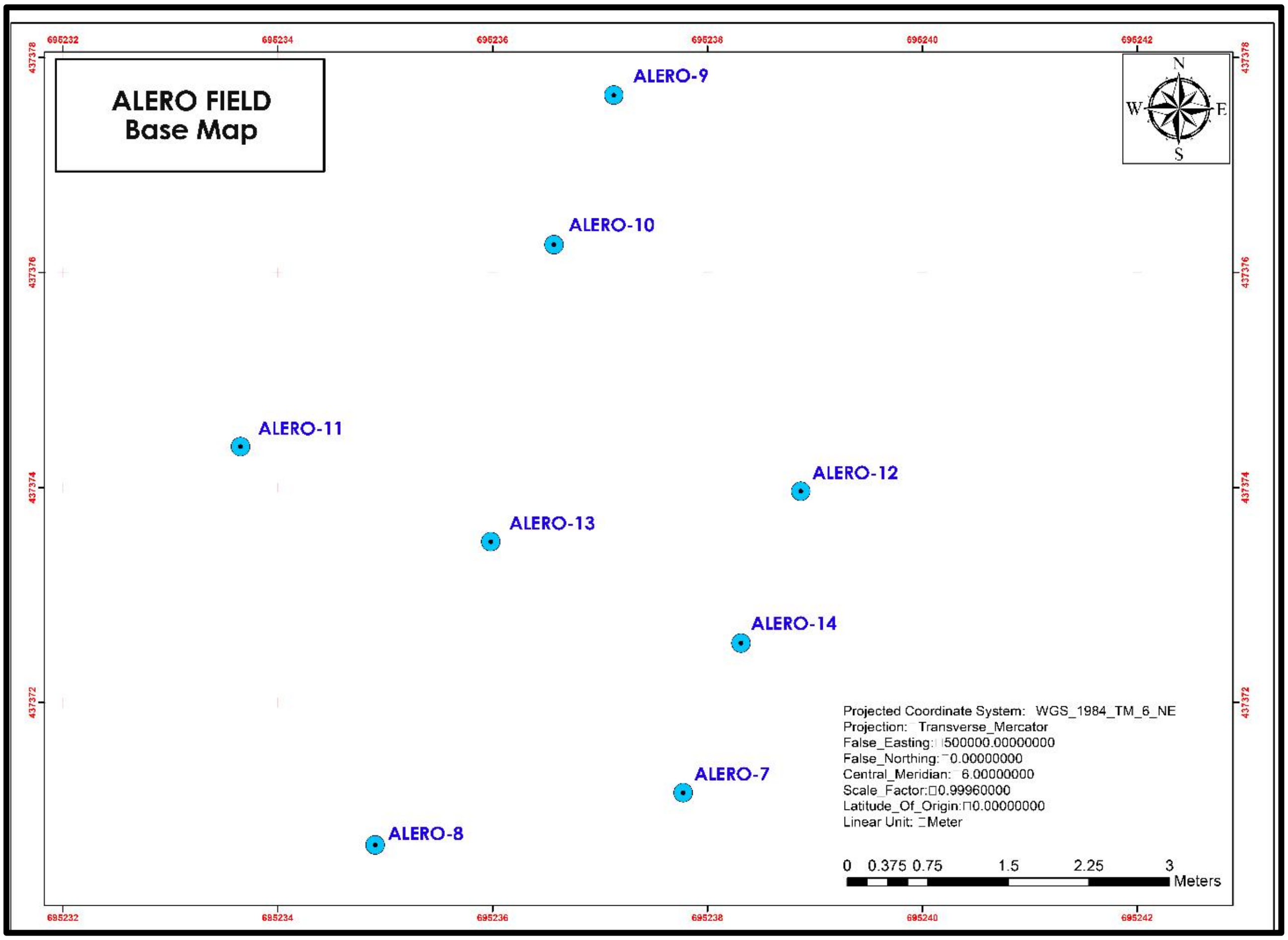

Figure 1: Base map showing the position of wells in Alero field

CHAPTER TWO

2.1 LITERATURE REVIEWS AND GENERAL GEOLOGY

Ogbamikhumi and Andrew, (2024) in their research work, ‘Reservoir Characterization and Reserve Estimation in Akings Field, Niger Delta, Nigeria.’, attempted to access the economic viability of the C reservoir in the Akings Field. They were able to achieve this using suites of wireline well logs from four wells and 3D seismic datasets which were evaluated to characterize the reservoir. Their results showed that the C reservoir in the Akings Field has a net thickness of about 176.5ft, payzone thickness of 129.90ft, total porosity of 30%, effective porosity of 26%, permeability of 2239.70mD. The fluid types being oil and water, the C reservoir was found to have a water saturation of 47%, and a prospect area of about 1049.46 acres.

According to Orji et al., (2019), a reservoir rock is considered to be an exploitable reservoir without stimulation if its permeability is greater than 100mD. Hence from the results of this research work of Ogbamikhumi and Andrew, the C reservoir has excellent sand quality for exploitation.

Maju and Ighodaro (2023) conducted a reservoir characterization study in X Field, onshore Niger Delta, using digital well logs from three wells. They identified four reservoirs (A, B, C, and D) with porosity (25–27%) and permeability (1863.22–2759.78 md), indicating good storage and fluid flow. Well X showed significant hydrocarbons, while Well Z had none. Estimated resources include 1.11×10^5 barrels of oil and 5.16×10^7 cubic feet of gas per acre in Well X, and 4.43×10^6 cubic feet of gas in Well Y. The reservoirs, ranging from slightly shaly sand to shaly sand, are interpreted as fluvial channel deposits with deltaic influences.

Kalu *et. al.*, (2020) carried out the re-evaluation of the Emerald Field in Niger Delta Basin to produce 3D structural model of the field as well as identify and estimate the petrophysical properties of the reservoirs in the field. This was achieved by the use of 3D seismic volume and 4 wells from the field and the combination of techniques of well log analysis. Integrated analysis of Gamma Ray, Resistivity, Neutron and Density logs show that 3 hydrocarbon-bearing reservoirs-Emy A, B and C were penetrated by 4 wells studied. The petrophysical analysis of the field reveals that reservoir porosity ranges from 10-29%, hydrocarbon saturation ranges from 0.75-0.84, water saturation ranges from 0.16-0.25%, volume of shale ranges from 0.24-0.33% and net-to-gross ranges from 0.72-0.93%. Five seismic facies were identified within the study area. Integrating the log motifs and results from the seismic facies analysis suggests the environment of deposition at different locations within the field to be distributary channel fills, overbank and floodplain deposits, which depicts paralic zone. Two prospects (Emerald prospect A and Emerald prospect B) and one hydrocarbon lead were identified within the study area. Results of risk evaluation and estimated volume of hydrocarbon in place ranked Emerald prospect B as highest. It is therefore concluded that prospect for hydrocarbon exist in the Emerald field and the identified prospect for hydrocarbon exist in the Emerald field and the identified prospect should be tested for production.

Adaeze *et. al* (2012) used petrophysical well logs and core data to analyze the reservoir characteristics of Uzek well, offshore Depobelts, Niger Delta Basin, Nigeria. Reservoir properties were gotten from well logs and cores to determine the reservoir quality. They identified four hydrocarbon bearing reservoirs (I, P, Q and R) during their analysis which are coarsening upward sequences with gradational/transitional basal and sharp upper contact reflecting sedimentation in high energy environments. The fluid types are basically oil and gas while the average porosity value ranged between 20-30%. The permeability value of the reservoirs was above 1000mD. Different cross plot was done which showed fairly strong linear relationships between two variables in the reservoirs. This indicated that Uzek Well reservoirs are permeable and have pores that are in strong communication and that the reservoirs can produce hydrocarbon in an economic quantity.`

Rahman et al.,(2021) Carried out petrophysical evaluation of the Titas gas field (Titas-15) for its reservoir characterization and to quantify the reservoir hydrocarbon prospects and gas productivity. The Quick Log Analysis Tool (QLAT) of PE^2 Essentials software was utilized for the computer-processed interpretation and the following well log data were inputted, gamma-ray (GR), density log (RHOB), density-porosity (DPHI), neutron-porosity (NDHI), resistivity logs, etc. Among three reservoir sand groups, three gas bearing sub-zones were identified in the upper sand group, which are primarily producing gas from the least net-pay of 9.5m, 39.5m and 28.5m, respectively. From the petrophysical evaluations carried out, the shale volume was calculated to comprise between 26.3% and 33.9%. The range of effective porosity was found to be 18.4-18.6%, permeability of 14.11-25.95mD. Additionally, the hydrocarbon saturation in the respective zones varied from 48%-60%. The results from the evaluations made on the Reservoir in the Titas gas field suggested it to be a good hydrocarbon reservoir, whereas the water saturation was found to be 40-52%. Moreover, the range of measured 'gas initially in place' in upper, middle and lower gas sands are 2371.6-2579.1, 10330.7-11206.1 and 6373.1-7110.5 MMscf, respectively, implying an adequate gas reserve on commercial criteria.

Amigun and Odole (2013) evaluated the petrophysical properties of the SEYI oil field in the Niger Delta to assess their impact on hydrocarbon potential and productivity. Using geophysical wireline logs, including gamma ray, resistivity, spontaneous potential, and density logs, key parameters such as porosity, permeability, fluid saturation, and net-to-gross thickness were analyzed across four wells. Seven reservoirs (A–G) were identified at depths of 2,396m to 3,429m, all containing hydrocarbons. Porosity ranged from **0.22 to 0.31**, while permeability varied between 881.58md and 14,425.01md, indicating good reservoir quality. Hydrocarbon saturation was highest in reservoirs F (91.97%) and G (85.11%), suggesting significant accumulations. The Movable Hydrocarbon Index (MHI) values (0.05–0.75) further confirmed the reservoirs' production potential. These findings highlight the SEYI field's high hydrocarbon prospectivity and the importance of petrophysical evaluation in reservoir assessment.

Chikiban et al. (2022) conducted a petrophysical evaluation of the Shahd SE field in the East Ras Qattara concession, Western Desert, Egypt, to assess hydrocarbon potential and productivity. The study proposed a systematic workflow that can be applied to similar evaluations. Well log data from four wells were analyzed, covering three formations: (1) Bahariya Formation, divided into Upper Bahariya (a shaly zone) and Lower Bahariya (the primary reservoir), and (2) Kharita Formation, composed of clean sand. Key petrophysical parameters were assessed, including shale volume (Vsh) from gamma-ray logs, effective porosity (φeff) from neutron logs and shale volume, and water saturation (Sw) using multiple equations. The Simandoux equation provided the most accurate results for the shale-rich Upper Bahariya (Chikiban et al., 2022).

The results revealed promising net reservoir and net pay thicknesses in all four wells, particularly within the Lower Bahariya Formation. Reservoir quality indicators, such as effective porosity and hydrocarbon saturation (Sh), remained consistent across the wells, confirming favorable conditions for hydrocarbon accumulation (Chikiban et al., 2022).

2.2 GENERAL GEOLOGY OF THE STUDY AREA

2.2.1 NIGER DELTA BASIN

The Niger Delta Basin is located in the Gulf of Guinea, positioned at a rifted triple junction associated with the opening of the southern Atlantic Ocean, a process that began in the Late Jurassic and continued into the Cretaceous. The delta itself started developing and accumulating sediments during the Eocene, with its sedimentary thickness now exceeding 10 kilometers.

Geographically, the Niger Delta Basin is situated in West Africa, specifically between latitudes 3º and 6ºN and longitudes 5º and 8ºE (see Figure 2). It is recognized as one of the most prolific petroleum-producing Tertiary deltas globally, containing approximately 5% of the world's hydrocarbon reserves. Additionally, it accounts for about 2.5% of the current global basin areas. To date, an estimated 34.5 billion barrels of recoverable oil and 93.8 trillion cubic feet of recoverable gas have been discovered within the basin.

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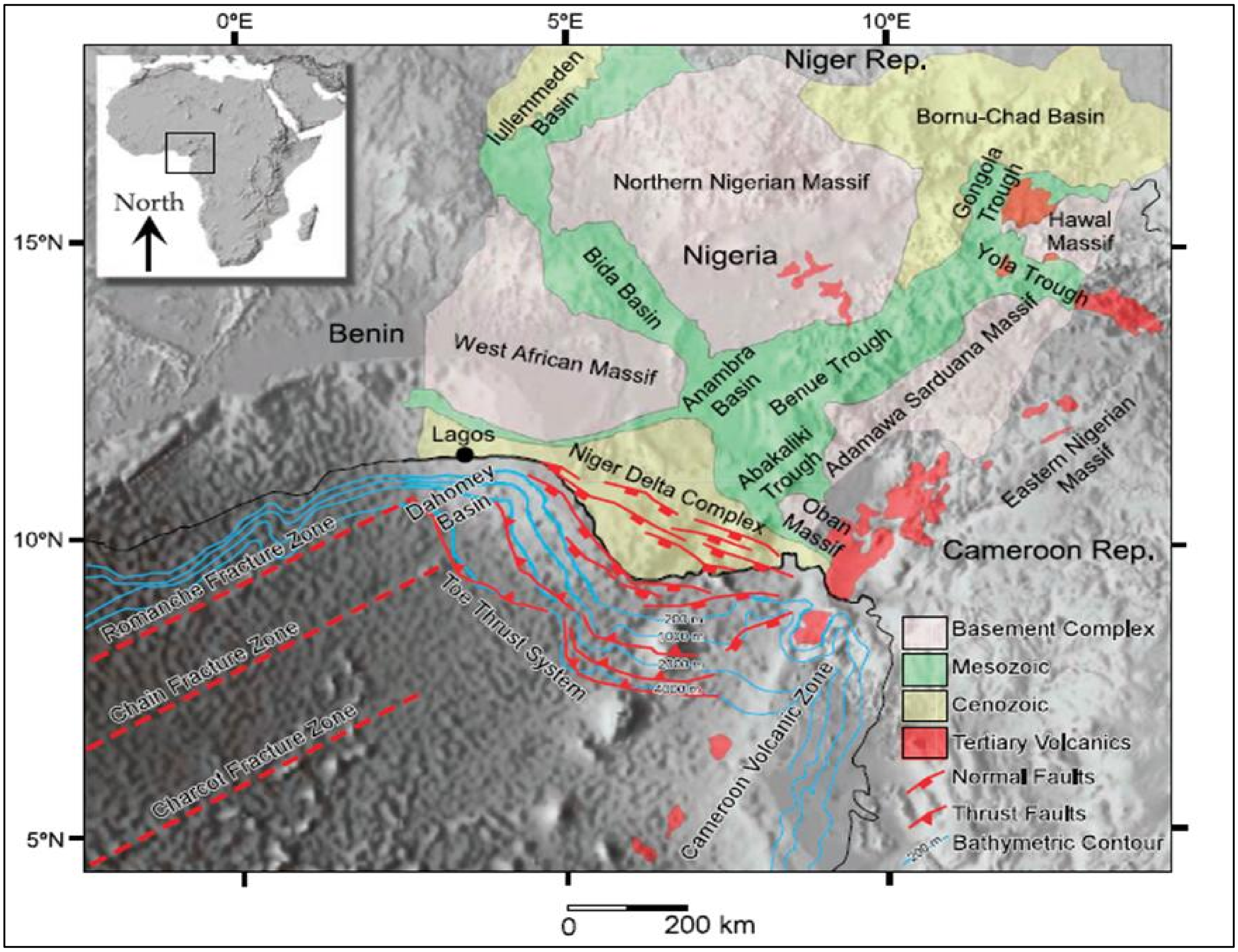


Figure 2: Map of Niger Delta showing the study area (Whiteman,

2.2.2 TECTONIC FRAMEWORK AND EVOLUTION OF THE NIGER DELTA BASIN

The evolution of the Niger Delta Basin is largely controlled by pre- and syn-sedimentary tectonic activities, as outlined by Evamy et al., (1978), Ejedawe (1981) and Stacher (1995). The basin's tectonic framework is linked to its development along a failed arm of a triple junction (RRR) system, known as an aulacogen, which formed during the breakup of the South American and African plates, coinciding with the opening of the South Atlantic Ocean (Burke et al., 1972; Whiteman, 1982).

Rifting in the Niger Delta Basin commenced in the Late Jurassic and extended into the Middle Cretaceous (Lehner and De Ruiter, 1977). This rifting phase led to the formation of numerous faults, including low-angle reverse faults. During this period, syn-rift sands were deposited, followed by the accumulation of shales in the Late Cretaceous, signaling a shoreline regression. Concurrently, the basin underwent extensional tectonics, leading to the development of high-angle normal faults and the rotation of fault blocks.

Subsidence occurred along major strike-slip faults that penetrated the lithosphere, which represented the landward extensions of the Chain and Charcot oceanic fracture zones (Emery et al., 1975). These fault systems played a crucial role in the formation of the Benue Trough and subsequently influenced the positioning of the main subsidence axes within the basin.

2.2.3 STRATIGRAPHY OF NIGER DELTA

The Niger Delta is fundamentally a prograding delta with three main lithostratigraphic units: the Akata, Agbada, and Benin Formations, arranged in ascending order (Figure 3). These formations exhibit stratigraphic continuity in both space and time, spanning from the Eocene to the Holocene. Some of their lateral equivalents are present in the Anambra Basin within the Lower Benue Trough.

The stratigraphy of the Niger Delta consists of an upper sequence of massive sand and gravel deposited under continental conditions, a transitional series of sandstone and shale intercalation formed under paralic conditions, and a basal marine shale section containing isolated sand lenses and turbidite deposits (Evamy et al., 1978).

According to Nwachukwu and Chukwura (1986), the depositional environments of the Niger Delta clastics range from the delta plain in a continental setting, through a transitional delta-front environment, to the prodelta and submarine fan environment typical of the deepwater setting. The delta plain environment consists primarily of sandstone units representing braided streams, point bars, channel fills, crevasse splays, and back-swamp shale deposits (Frankl and Cordry, 1967). The delta-front environment features tidal channels, beach sands, lagoons, distributary mouth bars, and barrier bar deposits. The submarine fan and prodelta environments are characteristic of the deepwater Niger Delta, where continuous pelagic and hemipelagic shale deposition occurs. Due to rapid sedimentation, the shale in this setting is largely under-compacted and over-pressured, containing isolated sand lenses and turbidite deposits (Avbovbo, 1978).

Benin Formation

The Benin Formation, located in the continental area, is the uppermost unit in the Niger Delta. It consists primarily of Late Eocene to Holocene continental deposits, including alluvial and coastal plain sands, with a thickness of approximately 2000 m (6600 ft) (Avbovbo, 1978). Onshore, in some coastal regions, the Benin Formation directly overlies the Agbada Formation (Kulke, 1995). Offshore, the continental sands of the Benin Formation become progressively thinner and eventually disappear near the edge of the continental shelf (Cohen and McClay, 1996). Seismic sections of this formation typically exhibit parallel reflectors with varying amplitude and frequency, along with low discontinuities that trend landward.

Agbada Formation

The paralic Agbada Formation is the primary petroleum-bearing unit in the Niger Delta. This paralic clastic sequence is present in all Niger Delta depobelts and ranges in age from Eocene to Pleistocene. The formation exceeds 3500 m (11,500 ft) in thickness and represents the main deltaic sequence, which accumulated in delta-front, delta-topset, and fluvio-deltaic environments (Doust and Omatsola, 1990). The primary reservoirs in the Niger Delta Basin are found within this formation, consisting of basin-floor fan deposits and channel sands

Akata Formation

The Akata Formation, positioned at the base of the Niger Delta Basin, is the oldest of the three main formations (see Figure 3). Composed predominantly of clays, shales, and silts, it forms the foundation of the deltaic sequence. This formation is widely regarded as the primary petroleum source rock and may also contain turbidite sand deposits. On seismic sections, the Akata Formation generally lacks internal reflections, except for a strong, high-amplitude reflection locally observed in the middle of the formation (Bilotti and Shaw, 2005).

The mid-Akata Formation plays a crucial role as a structural marker for delineating detachment levels, typically appearing on seismic sections as transparent and chaotic reflections. Its thickness varies significantly, ranging from approximately 2000 m (6,600 ft) to 7000 m (23,000 ft), with deeper offshore sections reaching up to 5000 m (16,400 ft) (Doust and Omatsola, 1990). Due to its composition of massive shale deposits interbedded with turbidite sands, the Akata Formation is often characterized on seismic sections by acoustically chaotic and transparent facies (Adeogba et al., 2005).

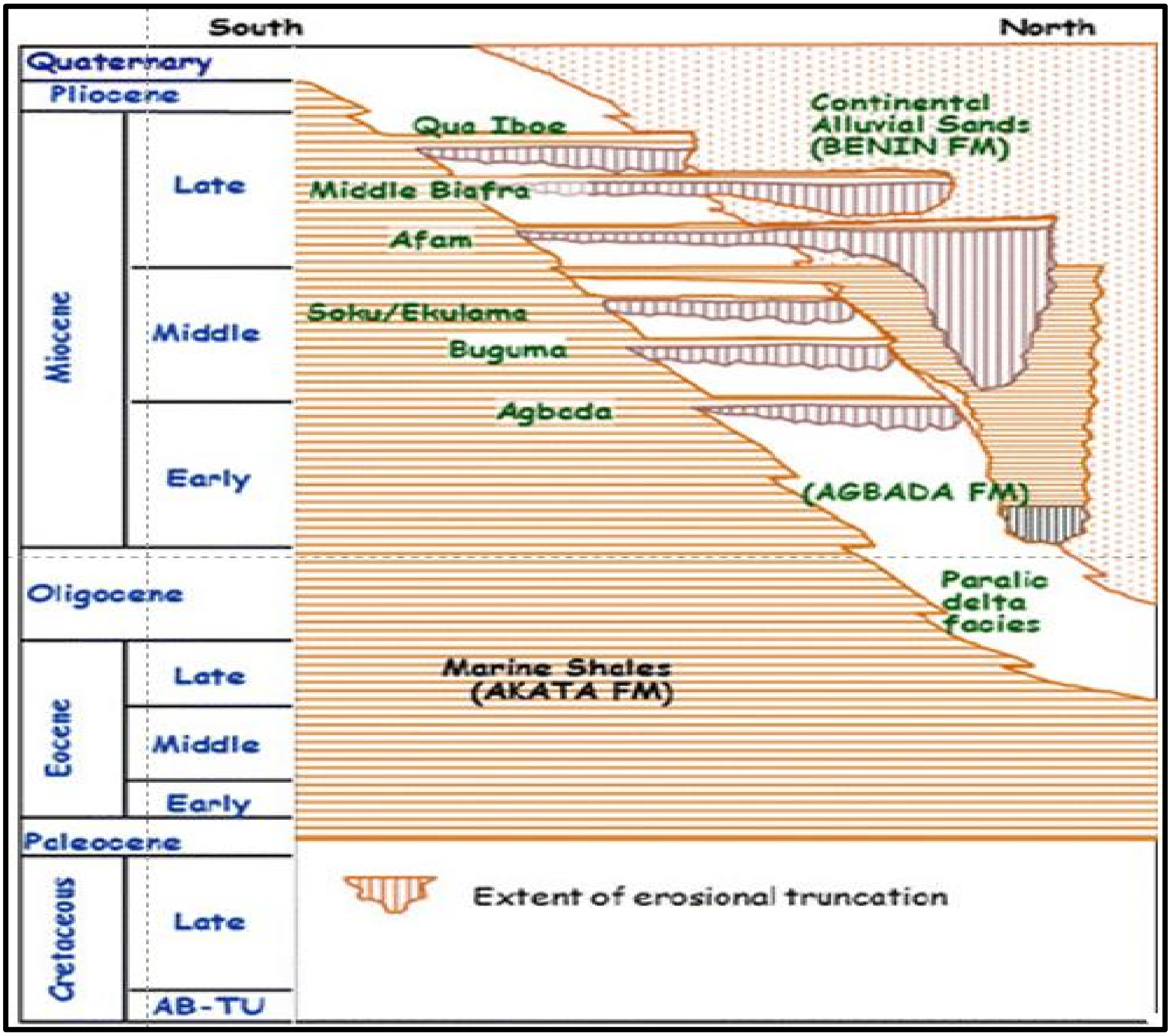


Figure 3: stratigraphy of the Niger Delta showing different Formations

2.2.4 DEPOBELTS OF NIGER DELTA PROVINCE

The deposition of the three main formations of the Niger Delta Basin has been attributed to five off-lapping siliciclastic sedimentation cycles, collectively known as depobelts. These depobelts range in width from 30 km to 60 km and prograde southwestward approximately 250 km over the oceanic crust and into the Gulf of Guinea. They are characterized by syn-sedimentary faulting, with their formation driven by variations in subsidence and sediment supply. As sedimentation progressed, subsidence caused the basin to deepen until it could no longer accommodate additional sediments, leading to a seaward shift in deposition. This shift created a new depocenter, forming a new depobelt. This repetitive process led to the sequential development of depobelts from the landward to the seaward region (see Figure 4).

Each depobelt has a distinct history of sedimentation, structural deformation, and petroleum accumulation. The ***northern delta depobelt***, located in the continental region, is the oldest and is characterized by the oldest growth faults. Seaward from this is the ***Greater Ughelli depobelt***, followed by the ***central swamp depobelt***, which contains well-developed structural elements such as deeper rollover crests shifting seaward with growth faults. Some researchers have further divided the central swamp depobelt into two separate units. Beyond this lies the coastal swamp depobelt, which is the most structurally complex onshore depobelt due to gravity-driven internal tectonics along the modern continental slope. Like the central swamp depobelt, it has also been subdivided into two units by some workers. The offshore depobelt, which is the most tectonically complex, extends into deeper waters and has been separated into shallow offshore and deep offshore depobelts.

These depobelts play a crucial role in the petroleum system of the Niger Delta, influencing reservoir distribution, structural trapping mechanisms, and hydrocarbon accumulation.

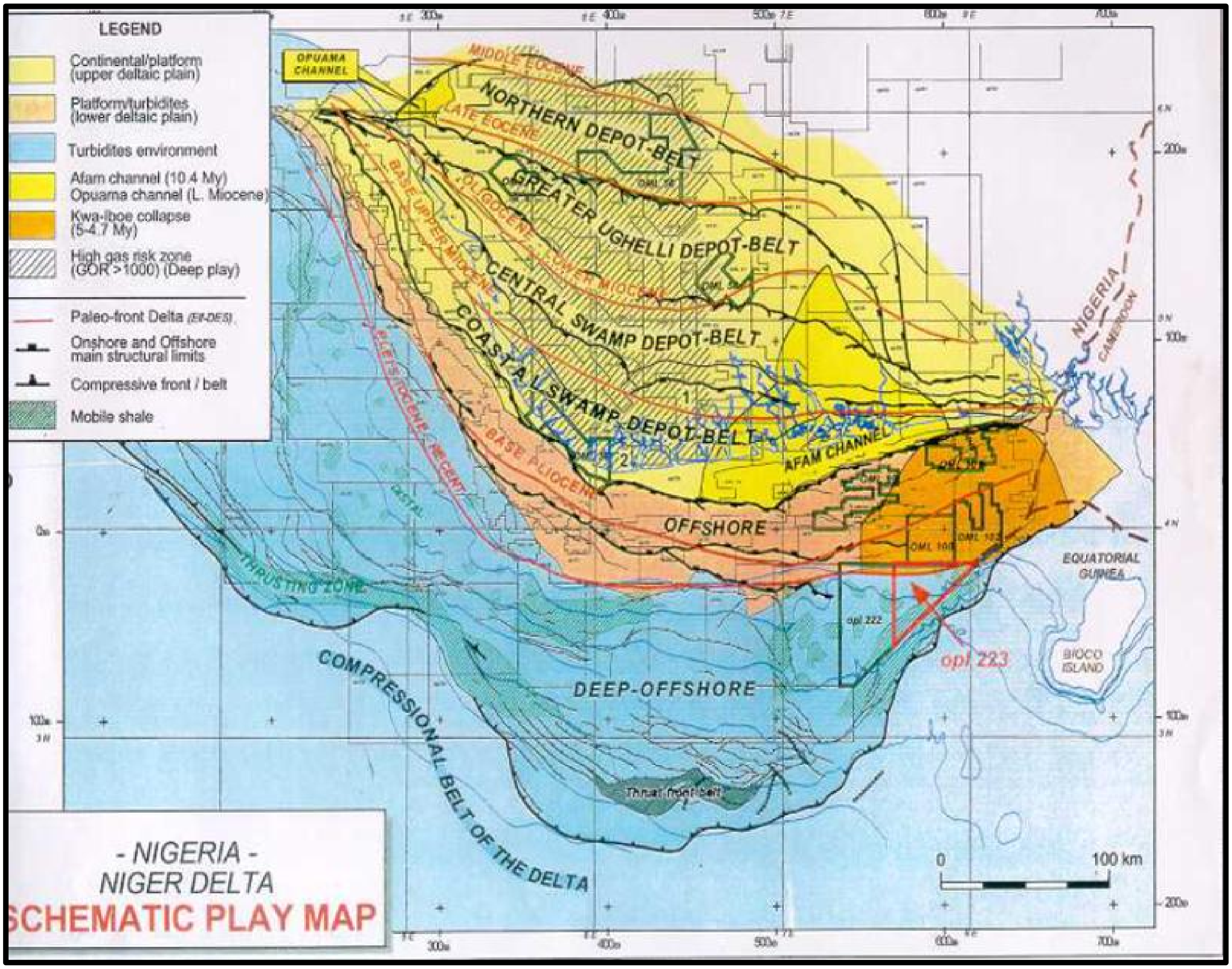


Figure 4: Map view of the different Depobelts in Niger Delta

2.2.5 STRUCTURAL FEATURES OF THE NIGER DELTA BASIN

The Niger Delta Basin is structurally divided into three distinct zones based on its tectonic framework. These include the upper extensional zone, located on the continental shelf, which results from crustal thickening; a transitional intermediate zone; and the lower contractional zone, which comprises the deep-sea portion of the basin. Normal faults are primarily formed due to extensional forces around the continental shelf, while compressional forces in the deep-sea region lead to the development of reverse faults. Evamy et al. (1978) identified the dominant structural features of the Niger Delta as growth faults and rollover anticlines.

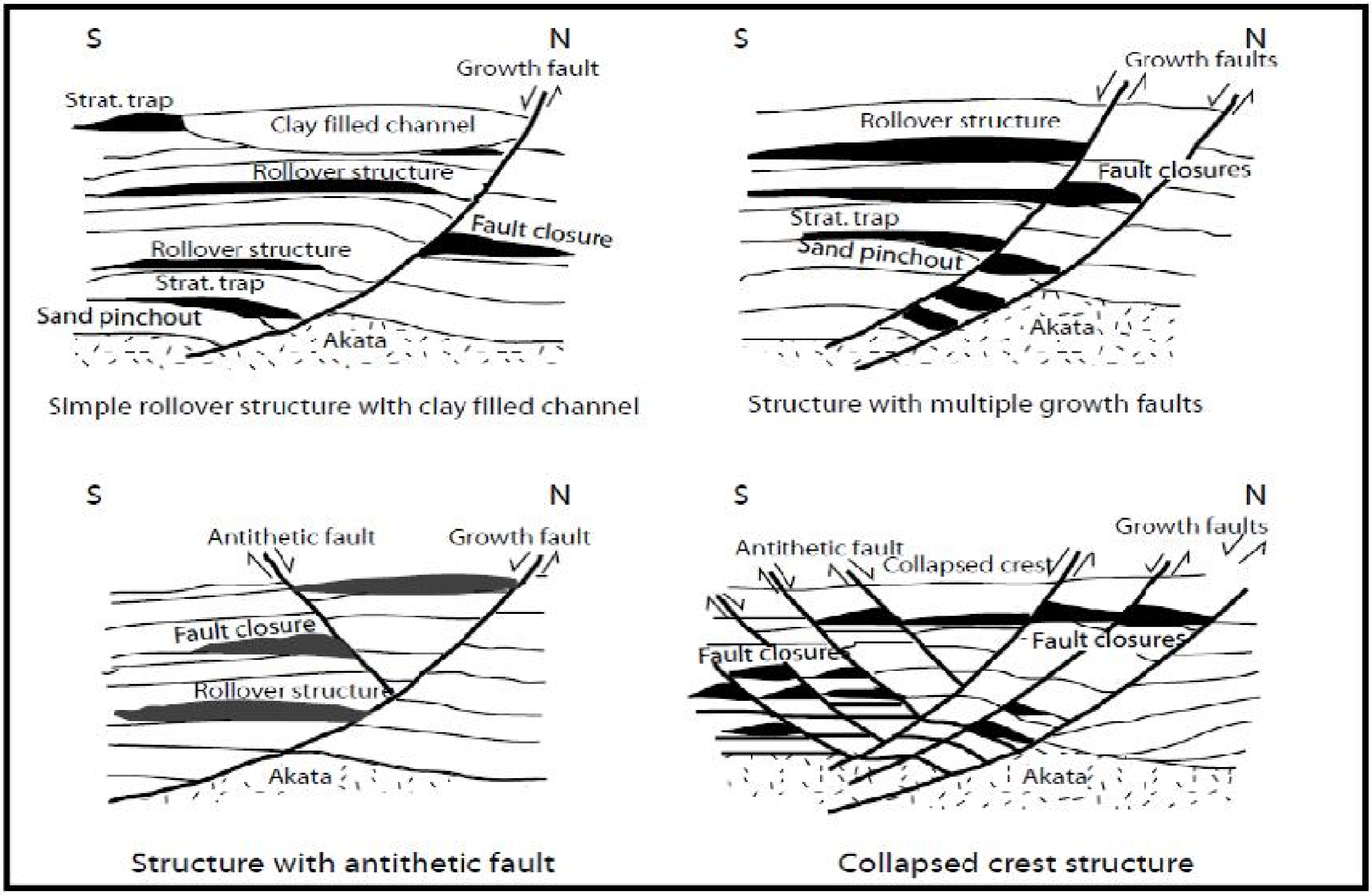


Figure.5: Niger Delta oil field structures and associated trap types. (Modified from Doust and Omatsola, 1990; Stacher, 1995).

2.2.5a Growth Faults

According to Whiteman (1982), growth faults derive their name from their formation around local depocenters, where they continue to evolve during sedimentation. This ongoing movement allows for greater sediment accumulation in the downthrown block compared to the upthrown block. Caillet and Batiot (2003) proposed that these faults develop due to the movement of deep-seated, over-pressured, ductile marine shale, with slope instability further influencing their formation. Whiteman (1982) also described growth faults as faults that displace an actively depositing surface. In the Niger Delta Basin, most listric faults exhibit a distinctive crescent-shaped geometry, with their concave side oriented toward the downthrown block, typically in a seaward direction. Growth faults tend to flatten with increasing depth and generally take on a listric form. These faults extend through the Agbada and Akata formations but terminate below the base of the Benin Formation. At greater depths, they may transition into low-angle reverse faults, with displacements reaching thousands of feet in toe-thrust zones.

These faults play a crucial role in hydrocarbon migration, serving as conduits that facilitate the movement of hydrocarbons from the Akata and Agbada formations into reservoir units within the Agbada Formation. Additionally, they can function as seals for hydrocarbon accumulation. When the fault throw surpasses the thickness of the reservoir, the fault zone acts as a seal, with its effectiveness largely influenced by the extent of shale smearing along the fault plane.

2.2.5b Structure building faults

The up-dip boundary of major rollover anticlinal structures is typically controlled by structure-building faults. These faults exhibit concavity toward the down-dip direction and tend to repeat in a similar pattern. Additionally, they play a key role in defining the boundaries of megastructures or depobelts.

2.2.5c Crestal Faults

One or more of this kind of faults, is found in a rollover structure. These faults vary from the structure-building faults as it shows lesser curvature with regards to the horizontal plane and they also show parallelism to the axis of the structure. (Figure 5). In the vertical planes, crestal faults appear to be steeper and also show less growth, tending to be less continuous.

2.2.5d Flank Faults

Flank faults are found at the flanks of major structures, towards the southern region; and at shallow levels, these faults often show major deformation associated with rollover. At regions of greater depth, flank faults show dip towards the south. Most K-type faults are flank faults, which show very closed spacing, resulting in fault block multiplicity.

2.2.5e Rollover Anticlines

The primary factor responsible for the formation of this type of structure is dip section reversal, which occurs due to the rotation of a fault block. This rotation is induced by movement along a listric fault plane, typically associated with gravity-driven faulting. Such curved fault planes are commonly linked to gravitational instability and occur concurrently with sediment deposition.

2.2.6 PETROLEUM AND ITS OCCURRENCE

DISTRIBUTION OF PETROLEUM IN THE NIGER DELTA

Petroleum is generally present throughout the Agbada Formation in the Niger Delta. Additionally, multiple directional trends form an "oil-rich belt" characterized by the largest fields with the lowest gas-oil ratios (Ejedawe, 1981; Evamy et al., 1978; Doust and Omatsola, 1990). This belt extends from the northwest to the southwest of the offshore region and follows several north-south trends near Port Harcourt. It roughly aligns with the transition between continental and oceanic crust and coincides with the zone of maximum sedimentary thickness. Initially, the distribution of hydrocarbons was thought to be influenced by the timing of trap formation in relation to petroleum migration, where earlier migrating oil was captured by older landward structures. However, Evamy et al. (1978) argued that in many rollover structures, structural growth and fault movement shifted progressively southward into younger deposits, showing no direct link between fault growth and petroleum distribution.

Ejedawe (1981) associated the oil-rich areas within the belt with five delta lobes, supplied by four distinct fluvial systems. He suggested that two key factors influenced this distribution: an increased geothermal gradient relative to the minimum gradient at the delta center and the generally older age of sediments in the belt compared to those farther seaward. These factors contributed to the highest "maturity per unit depth" observed in the sediments within this belt. Weber (1987) further proposed that this "golden lane" of petroleum accumulation aligns with a concentration of rollover structures across depobelts, characterized by short southern flanks and limited paralic sequences to the south. Doust and Omatsola (1990) suggested that petroleum distribution may be influenced by variations in source rock composition (with paralic sequences in the west playing a greater role) and/or the effects of remigration and segregation.

2.2.6a SOURCE ROCK

There has been extensive debate regarding the petroleum source rock in the Niger Delta (e.g., Evamy et al., 1978; Ekweozor et al., 1979; Ekweozor and Okoye, 1980; Doust and Omatsola, 1990). Potential sources include contributions from the interbedded marine shale within the Agbada Formation, the Akata shale, and possibly a Cretaceous shale (Weber and Daukoru, 1975; Evamy et al., 1978; Ejedawe et al., 1979; Ekweozor et al., 1979; Doust and Omatsola, 1990; Haack et al., 1997). The Agbada Formation contains sections with sufficient organic carbon content to qualify as effective source rocks (Ekweozor and Okoye, 1980; Nwachukwu and Chukwura, 1986). However, these sections generally lack the necessary thickness to support a world-class oil province and are considered immature in several areas of the delta (Evamy et al., 1978; Stacher, 1995).

In contrast, the Akata shale, which underlies the Agbada Formation, possesses substantial thickness and is large enough to generate the volume of oil required for a world-class petroleum province like the Niger Delta. Ejedawe et al. (1984) used sediment maturation models to conclude that in the central part of the delta, oil is primarily generated by the

Agbada shale, while gas is derived from the marine Akata shale. In other parts of the delta, they suggested that both shale types contribute to oil generation. Doust and Omatsola (1990) proposed that while both the Agbada and Akata Formations contain source rock intervals, the majority of the source material is likely within the Agbada Formation. Conversely, Stacher (1995) argued that the Akata Formation is the only source rock with sufficient thickness and burial depth to align with the oil generation window. Based on organic matter composition and type, Evamy et al. (1978) suggested that both the Akata and Agbada shales serve as the primary source rocks for Niger Delta petroleum.

2.2.6b RESERVOIR ROCK

Oil and gas in the Niger Delta are primarily produced from sandstone and unconsolidated sands, which dominate the paralic Agbada Formation. The characteristics of reservoirs within this formation are influenced by both the depositional environment and burial depth. The known reservoir rocks range in age from the Eocene to the Pliocene and are often stacked, with thicknesses varying from less than 15 meters to 100 meters, exceeding 45 meters in certain locations (Evamy et al., 1978). Thicker reservoirs likely result from composite accumulations of stacked channel systems (Doust and Omatsola, 1990).

Based on reservoir geometry and quality, Kulke (1995) identified the most significant reservoir types as point bars within distributary channels and coastal barrier bars, which are intermittently interrupted by sand-filled channels. The lateral variation in reservoir thickness is largely controlled by listric faults, with reservoirs thickening toward the fault within the down-thrown block (Weber and Daukoru, 1975).

In the distal regions of the delta complex, deep-sea channel sands, low-stand sand bodies, and proximal turbidites have been identified as potential reservoirs (Beka and Oti, 1995). Burke (1972) described three primary deep-water basin floor fans that were likely active throughout the delta's evolution. However, these fans are smaller compared to those associated with other major deltas. This is attributed to the substantial deposition of sands from the Niger-Benue system on the delta top, which were subsequently buried along with the proximal sections of the fans as successive depobelts migrated seaward (Burke, 1972).

2.2.6c TRAPS AND SEALS

Most of the known traps in the Niger Delta fields are structural, although stratigraphic traps are also present within the basin. Structural traps primarily formed alongside the syn-sedimentary deformation of the Agbada paralic sequence (Evamy et al., 1978; Stacher, 1995). The complexity of these structures increases from north to south, corresponding to the transition from older to younger depobelts. This trend is driven by the growing instability of the under-compacted, over-pressured marine Akata shale. Doust and Omatsola (1990) identified several structural trapping configurations, including simple rollover structures, clay-filled channels, structures with multiple growth faults, structures with antithetic faults, and collapsed crest structures.

Stratigraphic traps are equally significant, particularly along the delta flanks, where sandstone accumulations are interbedded between marine shale diapirs (Beka and Oti, 1995).

The primary seal rock in the Niger Delta is the interbedded shale within the Agbada Formation. This shale provides three key types of seals: clay smears along faults, vertical seals, and interbedded sealing units, where faulting juxtaposes reservoir sands against shale (Doust and Omatsola, 1990). Additionally, on the delta flanks, clay-filled canyons—formed through erosion during the early to middle Miocene—serve as critical top seals for several major offshore fields (Doust and Omatsola, 1990).

2.2.6dPETROLEUM GENERATION AND MIGRATION

Evamy et al. (1978) established the top of the present-day oil window in the Niger Delta at the 240ºF (115ºC) isotherm. In the northwestern part of the delta, the oil kitchen is located within the upper Akata Formation and the lower Agbada Formation. However, moving southeast, the oil kitchen extends deeper stratigraphically, reaching depths of up to 4000 meters below the upper Akata/lower Agbada sequence (Evamy et al., 1978). Several researchers (Nwachukwu and Chukwura, 1986; Doust and Omatsola, 1990; Stacher, 1995) have linked the distribution of the oil window's top to sediment thickness and the sand/shale ratios of the overlying rock, particularly the Benin and Agbada Formations.

The Benin Formation exhibits the lowest thermal gradient, ranging between 1.3ºC and 1.8ºC per 100 meters. The Agbada Formation has a moderate thermal gradient of approximately 2.7ºC per 100 meters, whereas the under-compacted, over-pressured marine Akata Formation has the highest gradient, reaching about 5.5ºC per 100 meters (Ejedawe, 1981). Consequently, within any depobelt, the depth at which a given temperature is reached is influenced by the overall distribution of sediments (sand and shale). In distal offshore regions, subsurface temperatures tend to be higher due to the lower proportion of sand. Beka and Oti (1995) suggest that hydrocarbon kitchen depths in these areas are likely greater than within the delta itself, as oil generation depth is controlled by a combination of factors such as temperature, time, and tectonic deformation.

Hydrocarbon migration from mature, over-pressured, and under-compacted shales in the more distal parts of the delta may resemble the process observed in the over-pressured shales of the Gulf of Mexico.

CHAPTER THREE

3.0 MATERIALS AND METHODOLOGY

3.1 MATERIALS

The materials used for this work include:

1. A Portable Computer with an installed reservoir assessment software: Schlumberger TechLog software to be precise.
2. The datasets for the well: Well logs (Gamma ray, Resistivity, Spontaneous potential, Neutron and density Logs)

3.2 WORKFLOW

The workflow is simply a step-by-step process which outlines the tasks and activities needed to complete this project. (Figure 6)

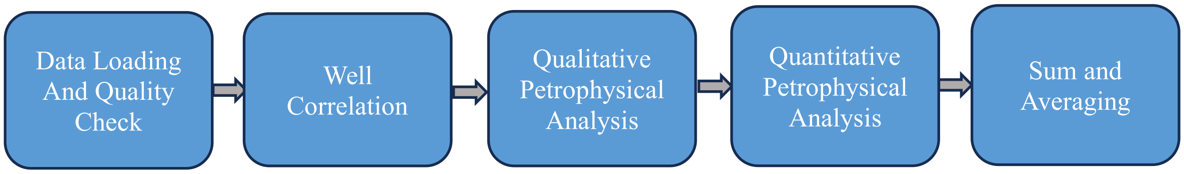


Figure 6: Project

3.3 DATA INVENTORY

Proper data inventory activities were carried out before the start of this work in order to ascertain project feasibility.

3.3.1 DATA USED

Well log data was used for carrying out this project. The table below shows the logs available for each well from the ALERO field. (Table 1)

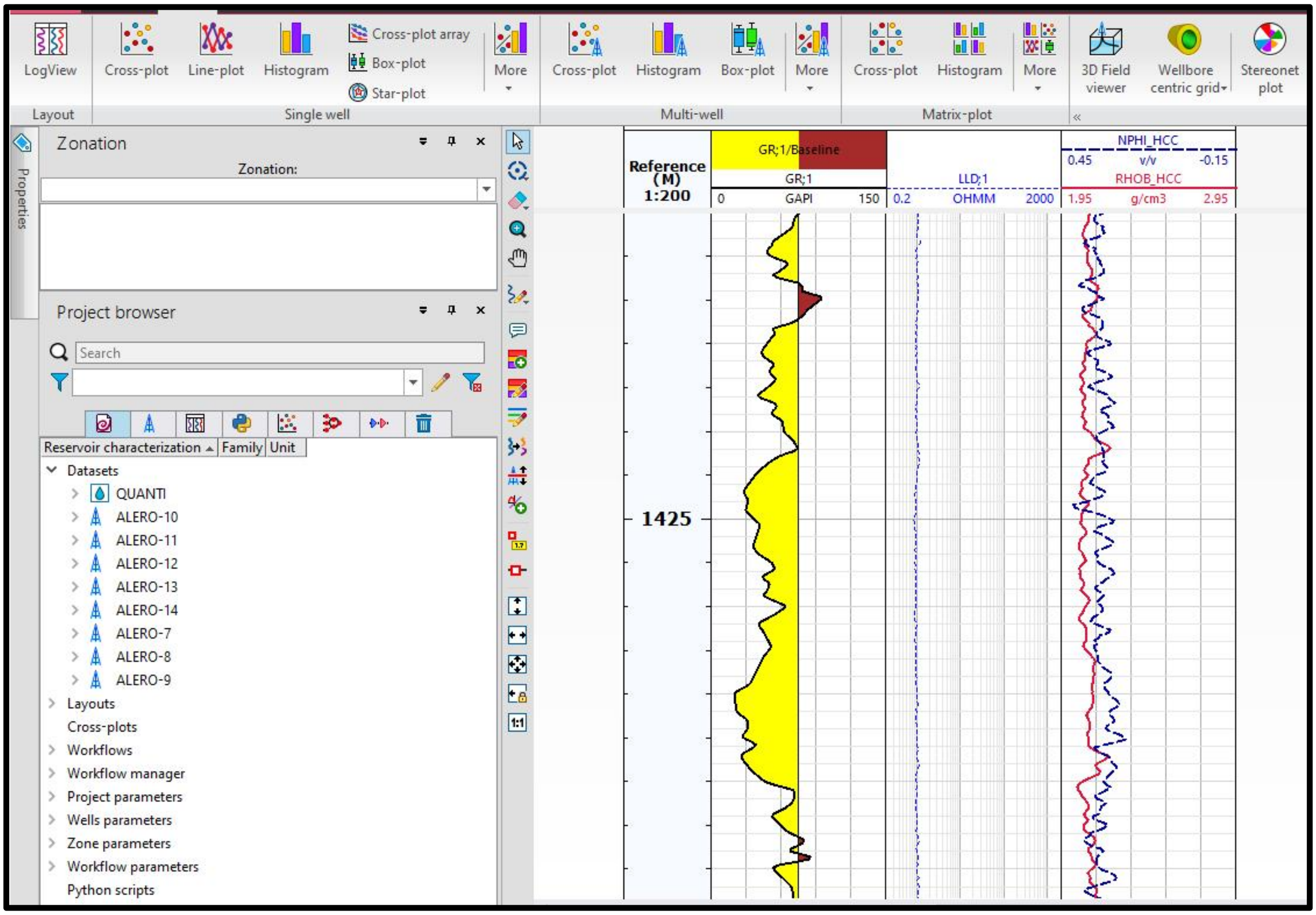
Table 1: Available logs for each well. Gamma Ray (GR), Resistivity (RT), Density (DN), Neutron (NT), Spontaneous potential (SP)

WELLS	**GR**	**RT**	**SP**	**NT**	**DN**
ALERO 7	Yes	Yes	No	Yes	Yes
ALERO 8	Yes	Yes	Yes	Yes	Yes
ALERO 9	Yes	Yes	No	Yes	Yes
ALERO 10	Yes	Yes	No	Yes	Yes
ALERO 11	Yes	Yes	No	Yes	Yes
ALERO 12	Yes	Yes	No	Yes	Yes
ALERO 13	Yes	Yes	No	No	No
ALERO 14	Yes	Yes	No	Yes	Yes

3.3.2 DATA LOADING AND QUALITY CHECK

The level of accuracy of results from a project as this highly depends on the accuracy at which data is imported into the software for analysis.

The image in below shows the well data on a ‘Logview’ window in the Techlog software. (Figure 7)



3.4 WELL CORRELATION

The logs were imported and displayed on the well section window, on which correlation was carried out using the lithology log (gamma ray log).

3.5 WELL LOG ANALYSIS

This involves the careful analysis of the various stratigraphic units in the four wells present. It entails the use of well logs such as gamma ray, for discrimination of lithology; resistivity log for discrimination of fluid; density and neutron logs for fluid and lithology discrimination as well. The hydrocarbon intervals in the reservoirs were delineated.

3.5.1 PETROPHYSICAL EVALUATION

Petrophysical evaluation is a process in reservoir characterization that involves the quantitative estimation and interpretation of the physical and fluid properties of rocks in the subsurface. These properties include permeability, effective and total porosity, water saturation, permeability, net-to-gross ratio and shale volume. Petrophysical properties provide insights into the potential of the reservoir, it's fluid content, and other properties of the rock. They are crucial for reservoir characterization and hydrocarbon exploration. Different mathematical formulars were used to obtain these properties from the well logs.

3.5.1a SHALE VOLUME

Shale volume refers to the proportion or percentage of shale present within a rock formation. It is a fundamental petrophysical parameter used in the analysis and characterization of reservoir rocks, particularly in hydrocarbon exploration and production. It was obtained from the gamma ray log with the formula:

$$VSH=0.083*(2^{(3.7*GR_{index})}-1) \quad \text{---}(1)$$

Where:

VSH=Shale volume

GR=Gamma ray

NB: The gamma ray index is the difference between the highest and lowest values for gamma ray log readings.

3.5.1b TOTAL POROSITY

Total porosity represents the total volume of pore space within a reservoir rock, including all interconnected and non-interconnected pores. It includes both effective porosity (contributing to fluid storage and flow) and non-effective or non-productive porosity. Total porosity is important in estimating the overall fluid storage capacity of a reservoir but does not directly indicate the volume of fluids available for production.

It was calculated from density log as shown in the following relationship:

$$\Phi= \frac{\rho_{ma}-\rho_b}{\rho_{ma}-\rho_{fl}} \quad \text{---(2)}$$

Where:

Φ=porosity derived from density log

ρ_{ma} =matrix (or grain) density (2.65gm/cm^3)

ρ_b= bulk density (as measured by the tool and hence includes porosity and grain density)

ρ_{fl}= fluid density (1.0gm/cm^3)

3.5.1c EFFECTIVE POROSITY

This is the portion of total porosity within a reservoir rock that contributes to fluid storage and flow. It represents the interconnected pore spaces accessible to fluids. It is a critical parameter for estimating fluid storage capacity and determining the potential for hydrocarbon accumulation and flow. Effective porosity reflects the amount of accessible pore space available for fluid storage and flow, directly impacting reservoir performance.

The mathematical formular used is expressed below.

$$\Phi_e = (1\text{-}VSH) * \Phi t \quad \text{---(3)}$$

Where:

Φ_e =Effective Porosity

VSH=Shale volume

Φt= Total porosity

3.5.1d PERMEABILITY

Permeability refers to the ability of a rock to allow fluids (oil, gas, or water) to flow through it. Permeability is an essential property in assessing reservoir productivity and determining the potential for fluid flow rates. Higher permeability indicates greater fluid mobility and better reservoir quality, allowing for efficient hydrocarbon production.

Permeability was attained with the formula:

$K(MD)=307+(26552*(\Phi_e)^2 - (\Phi_e * S_w)^2$ --(4)

Where:

K=Permeability

Φ_e=Effective porosity

SW=water saturation

3.5.1e WATER SATURATION

Water saturation represents the fraction of pore space within a reservoir rock that is occupied by water. It is typically expressed as a percentage. Water saturation is a crucial property for reservoir characterization as it helps determine the extent of water flooding within the reservoir and its impact on hydrocarbon production

This is the amount of water contained in the reservoir. It is obtained from the resistivity log.

S_w= SQRT (2.5/RES) --(5)

Where:

S_w= water saturation

RES=Resistivity

3.5.1f HYDROCARBON SATURATION

Hydrocarbon saturation refers to the fraction of pore space within a reservoir rock that is occupied by hydrocarbons (oil or gas). It is typically expressed as a percentage. High hydrocarbon saturation indicates a reservoir with a significant amount of oil or gas present, which is desirable for commercial production. It can be calculated by subtracting the value for water saturation from 1

$SH = 1 - Sw$ ---(6)

3.5.1g NET-TO-GROSS RATIO

The net to gross ratio (N/G ratio) is a measure of the proportion of reservoir rock that meets specific criteria for porosity, permeability, and lithology. It represents a fraction between the net reservoir thickness which is the thickness of rock within the reservoir that has sufficient porosity and permeability to store and transmit fluids (Hydrocarbons or water), and the Gross reservoir thickness which is the total thickness of the rock interval being evaluated, including both reservoir-quality rock and non-reservoir rock such as shale of impermeable layers.

$NTG = NH/NG$ ---(6)

Where:

NTG-Net-to-gross

NH=Net Reservoir thickness

NG=Gross thickness

CHAPTER FOUR

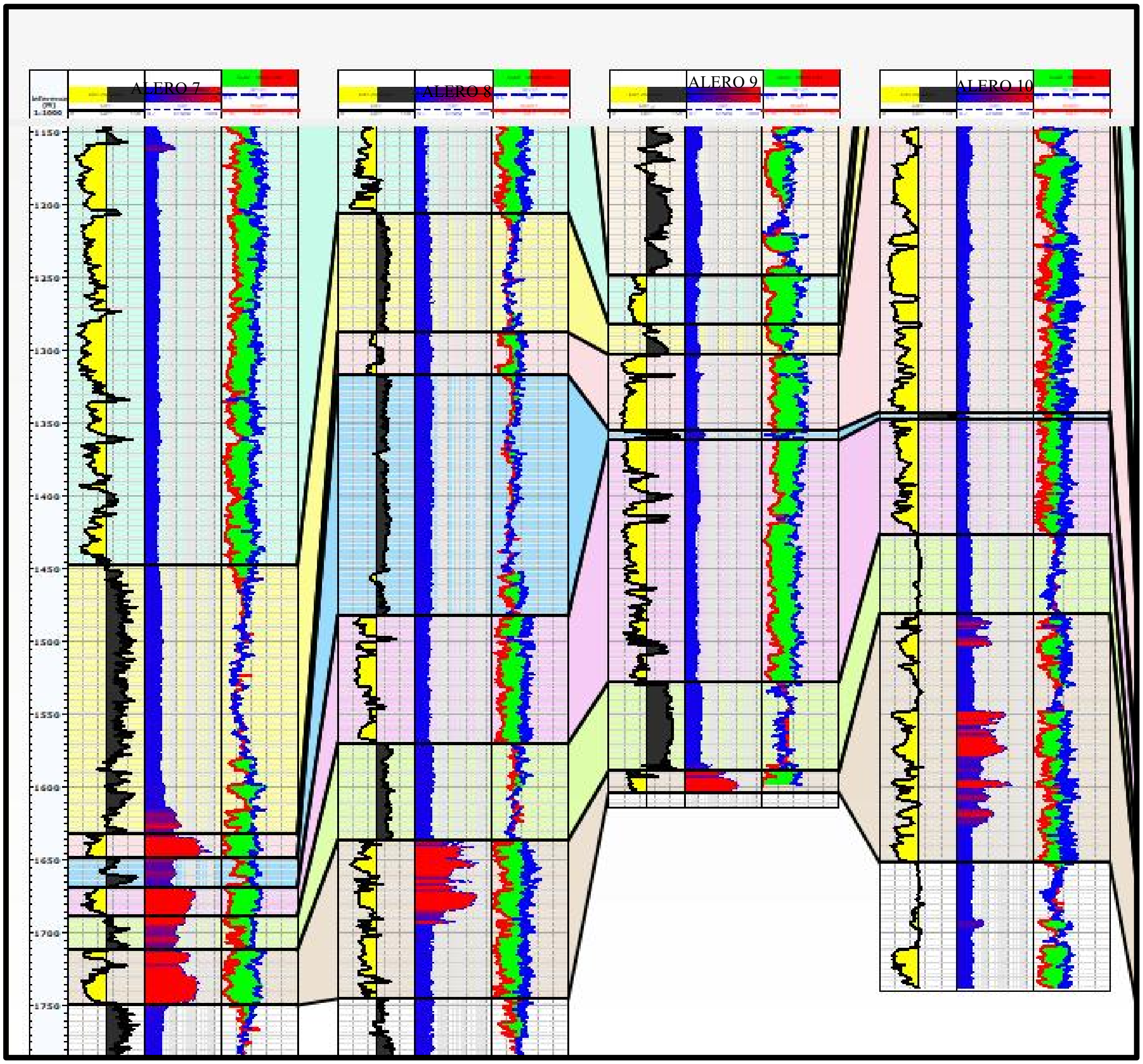
4.0 RESULTS AND DISCUSSIONS

4.1 QUALITATIVE INTERPRETATION

Upon examination of the Gamma Ray log, two lithologies were Identified and correlation established across 8 wells in the ‘ALERO’ field (Alero 7, 8, 9, 10, 11, 12, 13, 14). Several reservoirs were identified across the wells but for the purpose of this project, focus is limited to Reservoir A and Reservoir C which are of interest.

The reservoirs in the wells were identified qualitatively using the log signatures; low Gamma Ray, high Resistivity, and favourable neutron and density readings, all of which are indicative of hydrocarbon presence.

The Correlation also gives an insight to the general stratigraphy of the ‘ALERO’ field.



Resv C

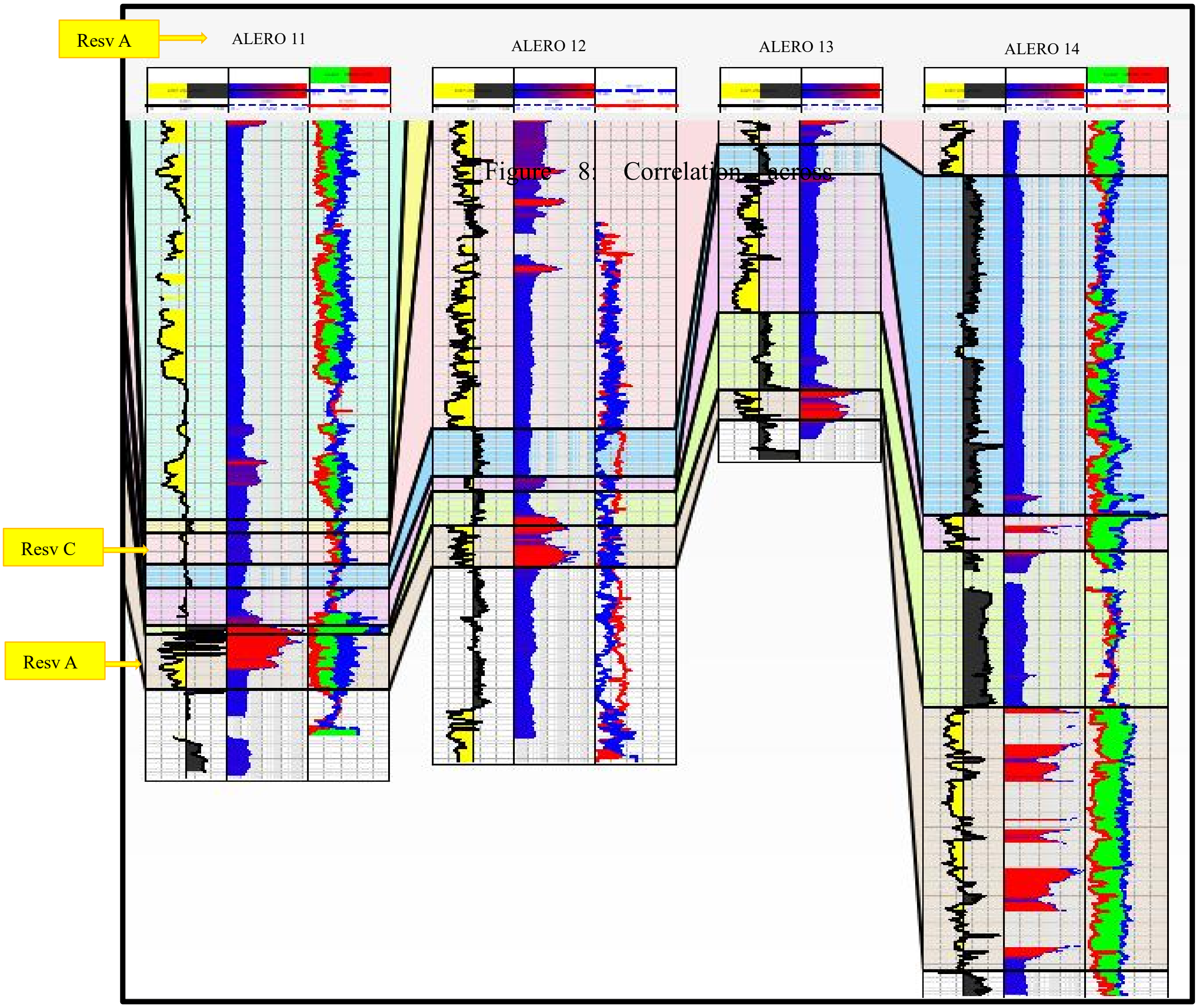


Figure 8: Correlation across

4.2 RESERVOIR THICKNESSES ACROSS WELLS

The thicknesses of the reservoirs A and C across the wells are presented in tables as follow (Tables 2, 3, 4, 5, 6, 7, 8, 9)

Table 2: Reservoir thicknesses for Alero 7

Reservoir	Top (m)	Bottom(m)	Gross thickness
A	1711.41	1749.49	38.08
C	1632.04	1648.20	16.16

Table 3: Reservoir thicknesses for Alero 8

Reservoir	Top (m)	Bottom(m)	Gross thickness
A	1636.14	1745.00	108.86
C	1287.65	1316.99	29.34

Table 4: Reservoir thicknesses for Alero 9

Reservoir	Top (m)	Bottom(m)	Gross thickness (m)
A	1588.69	1603.54	14.85
C	1302.90	1354.25	51.35

Table 5: Reservoir thicknesses for Alero10

Reservoir	Top (m)	Bottom(m)	Gross thickness (m)
A	1481.11	1651.7	170.57
C	1079.71	1342.13	262.42

Table 6: Reservoir thicknesses for Alero 11

Reservoir	Top (m)	Bottom(m)	Gross thickness (m)
A	1760.10	1799.96	39.86
C	1686.45	1709.11	22.67

Table 7: Reservoir thicknesses for Alero 12

Reservoir	Top (m)	Bottom(m)	Gross thickness (m)
A	1680.8	1711.31	30.53
C	1380.08	1609.92	229.84

Reservoir	Top (m)	Bottom(m)	Gross thickness

Table 8: Reservoir thicknesses for Alero 13

A	1581.69	1603.43	21.74
C	1325.54	1402.64	77.1

Table 9: Reservoir thicknesses for Alero 14

Reservoir	Top (m)	Bottom(m)	Gross thickness (m)
A	1812.77	2005.78	193.01
C	1141.97	1425.19	283.23

4.3 EVALUATION OF PETROPHYSICAL PARAMETERS

With the aid of the well logs, petrophysical analysis was carried out on reservoirs A and C. The analysis carried out revealed that the shale volume for Reservoir A across the wells ranges from about 16% to 28%; total porosity: 31% to 34%; effective porosity: 25% to 29%; permeability: 9962.25mD to 12912.90mD; water saturation: 7% to 24% and hydrocarbon saturation: 75% to 93%, While for Reservoir C across the wells; shale volume 10% to 36%%; total porosity: 28% to 33%; effective porosity: 21% to 29%; permeability: 10174.20mD to 12498.70mD; water saturation: 5% to 59% and hydrocarbon: 40% to 95%.

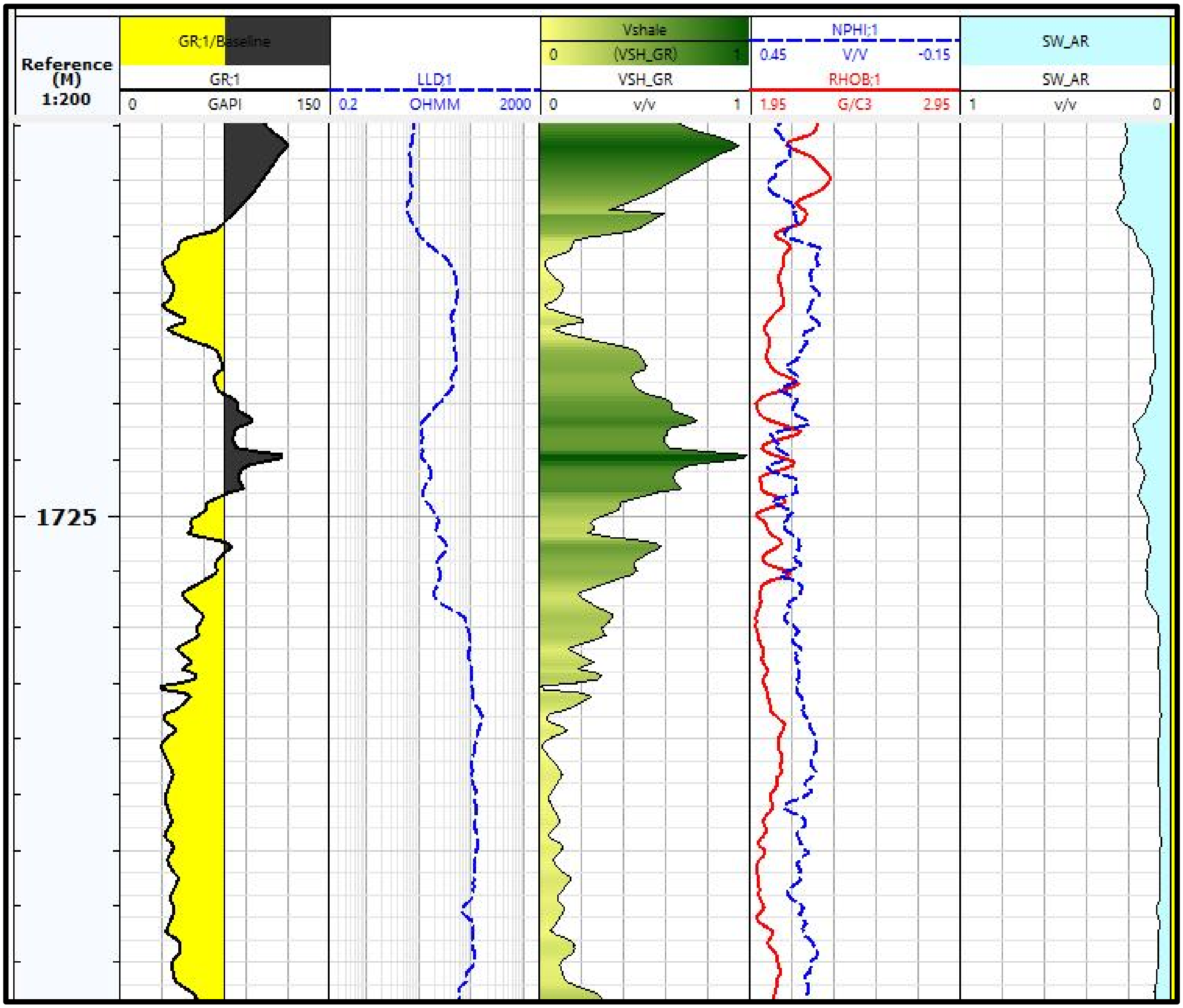


Figure 10: Log responses; Reservoir

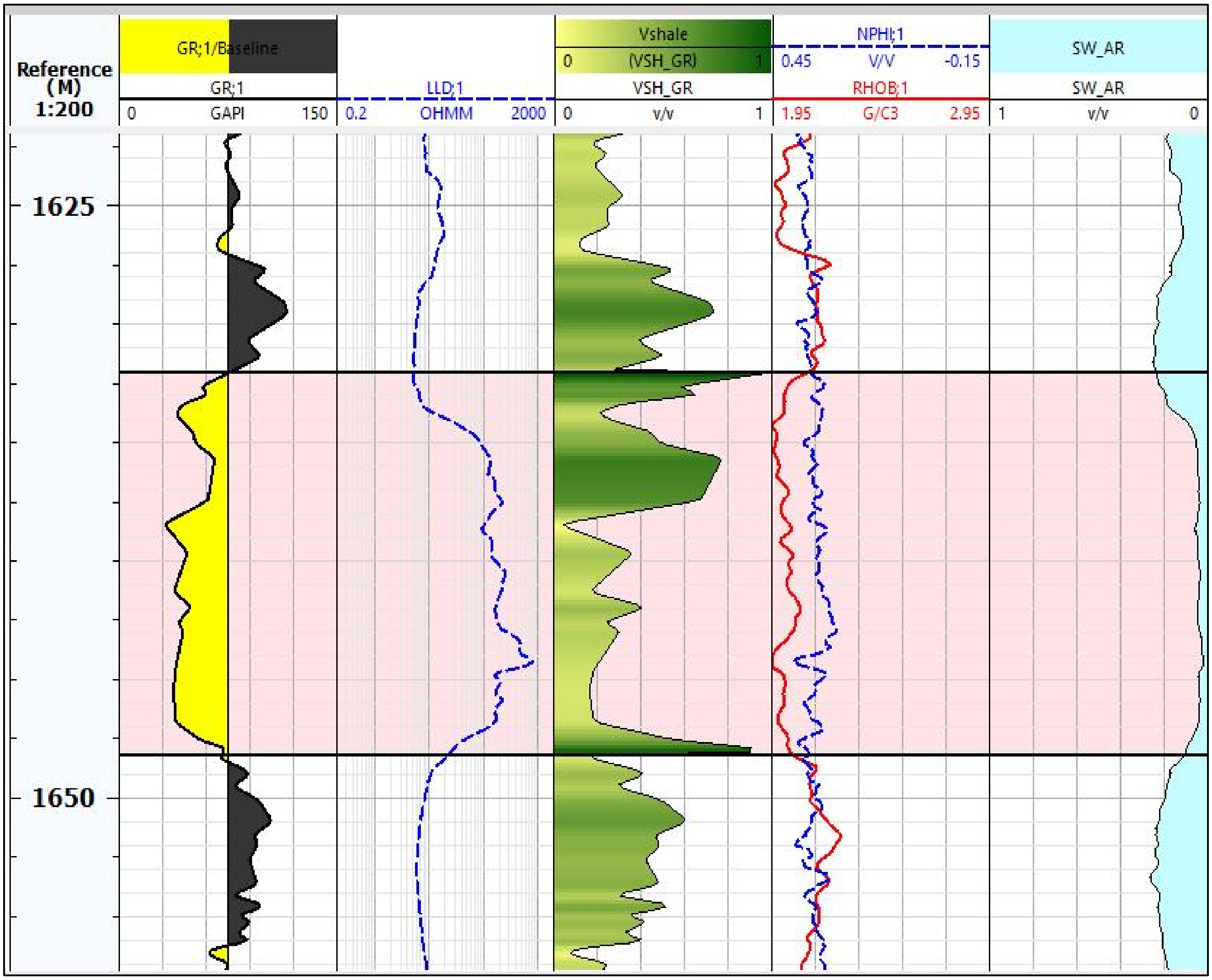


Figure 11: Log responses; Reservoir

The tables below summarize the results of the petrophysical evaluation of reservoirs A and C. (Table 10, Table 11)

Table 10: Spatial variation of Reservoir A properties across wells

Wells	**NTG**	**VSh**	**Total P**	**Effective P**	**W Sat.**	**HC Sat**	**Permeability (mD)**	**Fluid Type**	**WOC (m)**	**Pay Zone (m)**
Alero 7	0.73	0.18	0.32	0.28	0.07	0.93	10446.20	Oil		38.08
Alero 8	0.79	0.28	0.33	0.27	0.23	0.75	11547.30	Oil & Water	1693.05	57.65
Alero 9	0.21	0.16	0.34	0.29	0.13	0.87	12912.90	Oil		14.85
Alero 10	0.43	0.28	0.33	0.27	0.24	0.76	11746.90	Oil & Water	1625.06	143.95
Alero 11	0.38	0.23	0.33	0.27	0.19	0.81	11341.10	Oil & Water	1785.58	25.48
Alero 12	0.52	0.26	0.32	0.26	0.09	0.91	10835.10	Oil		30.53
Alero 13	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Alero 14	0.36	0.27	0.31	0.25	0.09	0.90	9962.25	Oil & Water	1995.92	183.15

Table 11: Spatial variation of Reservoir C properties across wells

Wells	**NTG**	**VSh**	**Total P**	**Effective P**	**W Sat.**	**HC Sat**	**Permeability (mD)**	**Fluid Type**	**OGC (m)**	**WOC (m)**	**Pay Zone**
Alero 7	0.51	0.26	0.33	0.28	0.05	0.95	12498.70	Oil			16.16
Alero 8	0.203	0.36	0.33	0.25	0.46	0.54	12124.20	water			
Alero 9	0.861	0.10	0.32	0.29	0.59	0.40	10253.40	water			
Alero 10	0.310	0.21	0.32	0.27	0.59	0.42	10745.00	water			
Alero 11	0.236	0.29	0.28	0.21	0.37	0.62	6010.94	Oil			22.67
Alero 12	0.379	0.27	0.32	0.26	0.42	0.58	10174.20	Oil & Water		1499.76	119.68
Alero 13	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Alero 14	0.285	0.23	0.33	0.28	0.49	0.50	12147.60	Gas, Oil & Water	1160.39	1199.80	53.83

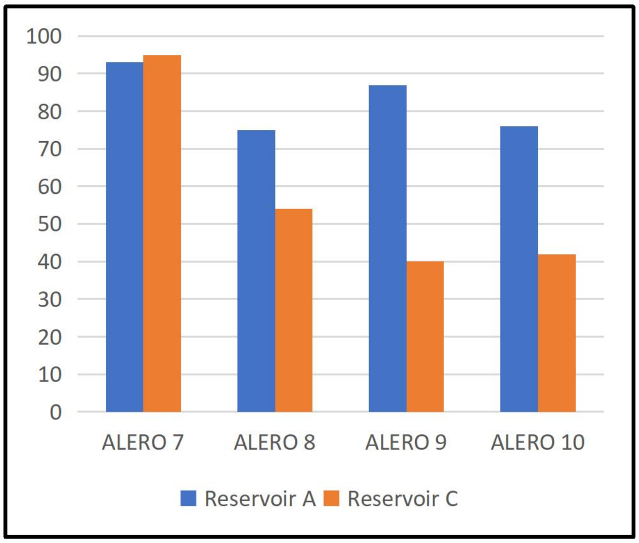


Chart 1: Hydrocarbon saturation in reservoirs A and C across wells

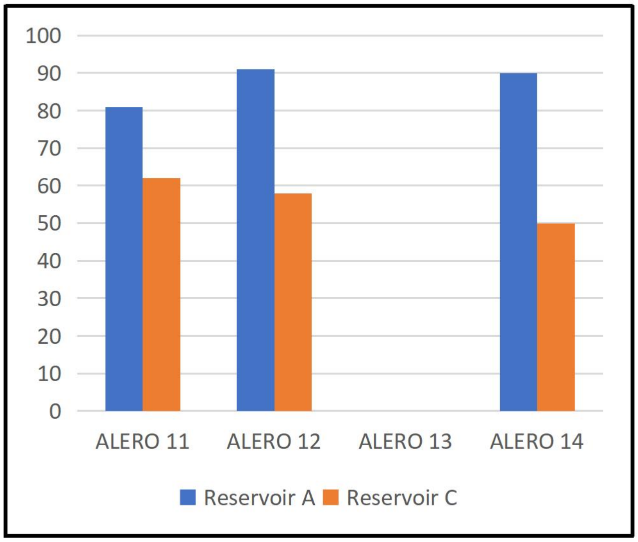


Chart 2: Hydrocarbon saturation in reservoirs A and C across wells

4.4 RESERVOIR TYPES AND QUALITIES

4.4.1 Reservoir A

The petrophysical evaluation of reservoir A reveals that it is a sandstone oil-bearing reservoir with associated water phase, as is observed from the fluid type distribution across the wells.

The presence of oil in the reservoir across multiple wells, along with variation in water-oil contact (WOC), suggests that the reservoir is laterally continuous.

Based on key petrophysical parameters, including net-to-gross (NTG), shale volume (VSh), porosity, water saturation (sw), hydrocarbon saturation (HC Sat), and permeability, the reservoir quality was assessed. From the results of the assessment, overall, Reservoir A is classified as a high-quality oil reservoir with excellent permeability, moderate-to-high porosity, and low water saturation across the wells, which indicates strong production potential.

4.4.2 Reservoir C

Petrophysical evaluation of Reservoir C suggests that it contains a combination of oil, gas, and water across different wells. While some wells (e.g., Alero 7 and Alero 11) contain only oil, others (e.g., Alero 8, 9, and 10) are water-bearing, and Alero 14 contains a mixture of gas, oil, and water. The presence of water in multiple wells suggests that the reservoir may have undergone significant water encroachment or may have poor hydrocarbon retention in certain areas.

From the overall results of the assessment of key petrophysical parameters, Reservoir C is revealed to exhibit moderate to good quality but with significant water presence in some wells and gas influence in Alero 14, which may complicate oil production.

CHAPTER FIVE
5.0 CONCLUSION AND SUMMARY

5.1 CONCLUSION

The petrophysical analysis of Reservoirs A and C in the ALERO field provides valuable insights into their hydrocarbon potential. Both reservoirs have been revealed to exhibit favourable properties across the wells, including moderate to high net-to-gross (NTG) ratios, effective porosity, high hydrocarbon saturation, and good permeability. However, variations in shale content (VSh), water saturation, as well as pay zone thickness across the wells suggest spatial heterogeneity in reservoir quality.

Reservoir A shows better permeability (10174.20mD to 12498.70mD) and overall hydrocarbon saturation (75% to 93%), making it a more promising candidate for oil production. On the other hand, Reservoir C contains mix of oil, water, and gas, with some wells revealing significant water saturation which may pose challenges during production. Correlation across the wells has also enhanced the understanding of the general stratigraphic framework of the ALERO field, aiding in reservoir delineation and potential field development planning.

5.2 SUMMARY

This research work provides insights into the petrophysical characteristics of Reservoirs A and C in the ALERO field, highlighting their hydrocarbon potential. Techlog software was utilized for petrophysical analysis, allowing for the evaluation of key reservoir properties. Both reservoirs exhibit moderate to high NTG ratios, effective porosity, and good permeability, though variations in shale content, water saturation, and pay zone thickness indicate spatial heterogeneity.

Reservoir A shows higher permeability (10,174.20mD – 12,498.70mD) and hydrocarbon saturation (75% – 93%), making it more promising for oil production. In contrast, Reservoir C contains a mix of oil, water, and gas, with some wells showing high water saturation, which may pose production challenges.

5.3 SUGGESTION FOR FURTHER STUDIES

For further studies, I suggest the integration of seismic inversion techniques to improve reservoir characterization by linking well log data with seismic attributes. Additionally, applying machine learning algorithms for petrophysical property prediction could enhance the accuracy of hydrocarbon identification. A comparative analysis of various water saturation models across multiple reservoirs would help refine Sw estimation, especially in shaly formations. Lastly, incorporating dynamic reservoir simulation with production data would provide deeper insights into reservoir performance and optimize recoveries.

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