

RESEARCH ARTICLE

ASSESSMENT OF RESERVOIR PERFORMANCE IN THE CZ FIELD, NIGER DELTA BASIN, UTILIZING INTEGRATED FACIES AND PETROPHYSICAL ANALYSES FOR PREDICTIVE MODELING

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ABSTRACT

The "CZ" field refers to a promising hydrocarbon reservoir situated inside the Niger Delta region in Nigeria. The field is characterised by the presence of three distinct reservoir zones, namely the Agbada, Benin, and Akata formations. The research employed a multidisciplinary methodology to assess the hydrocarbon potential of the field, using techniques such as well log analysis, seismic interpretation, and petrophysical modelling. The findings of the research indicate that the "CZ" region has noteworthy potential for hydrocarbon resources. The aggregate assessed in-situ reserves of oil and gas amount to 1.2 billion barrels of oil equivalent (BOE) and 8.0 trillion cubic feet (TCF) of gas, correspondingly. The expected recovery factor for oil in the field is 20%, while for petrol it is predicted to be 80%. The study has identified a number of issues that want attention in order to advance the subject of "CZ." The problems encompass several factors, namely the existence of water and gas within the reservoir, the intricate structural geology of the field, and the field's distant geographical position. Notwithstanding these obstacles, the "CZ" sector exhibits the capacity to emerge as a significant hydrocarbon producer. The research offers a significant foundation for subsequent assessment and advancement of the discipline.

KEYWORDS

Petroleum Play Elements, Reservoir Quality, Thin Sand Reservoir, Sequence Stratigraphy, Systems Tracts

1. INTRODUCTION

Hydrocarbons are extremely important economically for Nigeria and many other countries across the world. To maximise the use of these resources, it is vital to understand the typical behaviour of the traditional reservoirs in which they are gathered (Ahmadova et al., 2021). The Earth is made up of a broad range of rocks with various characteristics, making it difficult to conduct a full examination of the planet's enormous resources. To perform a thorough analysis of the subsurface and its contents, particularly hydrocarbons, a full understanding of the Earth's physical and chemical properties is required. To achieve accurate reserve estimation and the development of successful reservoir management plans, a thorough understanding of the depositional environment within a specific region is required (Agbasi et al., 2018; Onyekuru et al., 2012).

Sand sedimentation in diverse depositional contexts is distinguished by a variety of patterns, compositions, and levels of variability. As a result, the reconstruction of depositional settings in clastic successions provides the best foundation for characterising and forecasting reservoir quality dispersion. The effectiveness of a reservoir is commonly evaluated using its petrophysical properties, which are greatly impacted by the heterogeneity of deposition at different scales and the presence of diagenetic processes (Essien et al., 2017; Agbasi et al., 2020). To effectively estimate reservoir performance and successfully apply reservoir management approaches, it is necessary to have a thorough understanding of facies fluctuations and their impact on reservoir quality.

Since the Tertiary period, the Niger Delta Basin has been firmly established as a particularly productive delta, famous for its important role in world petroleum production (Inyang et al., 2021). Extensive study has been conducted to have a complete understanding of the depositional conditions and petrophysical features of reservoirs in the Niger Delta Basin. Nton and Adesina (2009) focused their inquiry on the Tomboy Field, which is located in the basin's maritime region (Nton and Adesina, 2009). The researchers made an important discovery concerning the deposition of reservoir sands in a variety of geological contexts, including tidal channels, barrier islands, mouth bars, and distributary channels. These sand deposits were also found to be scattered across typical development faults and anticlinal structures (Agbasi et al., 2021; Harry et al., 2022).

As part of their different research, examined the Uzek well separately. On the other hand, investigated the Amma field, Bob field, Apete field, and DC70X reservoirs situated inside the Mbakan field. The aforementioned research has revealed significant differences in the petrophysical characteristics of reservoirs across the Niger Delta Basin. The observed variances can be linked to the depositional environment's different properties (Alao et al., 2013; Rotimi et al., 2013; Omoboriowo et al., 2014).

The CZ Field is an offshore oil and gas field located inside the Niger Delta Basin. The field was discovered in 2010, and it is now in an active development phase. The reservoir is located inside the CZ. The field is classed as a clastic reservoir, which means that it is predominantly made up of sedimentary rocks that are made up of pieces or grains. The

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reservoir was formed and deposited inside a deltaic environment, which is marked by silt buildup near the confluence of a river and a larger body of water, such as a lake or ocean. The goal of this study is to determine the depositional environment, evaluate and compare the spatial distribution of water saturation, permeability, and porosity within the designated study area, distinguish distinct sand bodies within the reservoirs, and predict the reservoir system's quality and efficacy.

2. GEOLOGICAL SETTING OF THE STUDY AREA

The Niger Delta is a physically remote sag basin located in the Equatorial Gulf of Guinea, near to West Africa's continental boundary. The Benue Trough to the north, the Anambra Basin to the east, and the Atlantic Ocean to the south and west define the physical limits of this region. According to Adedapo et al. (2014), the basin is around 75,000 km² in size.

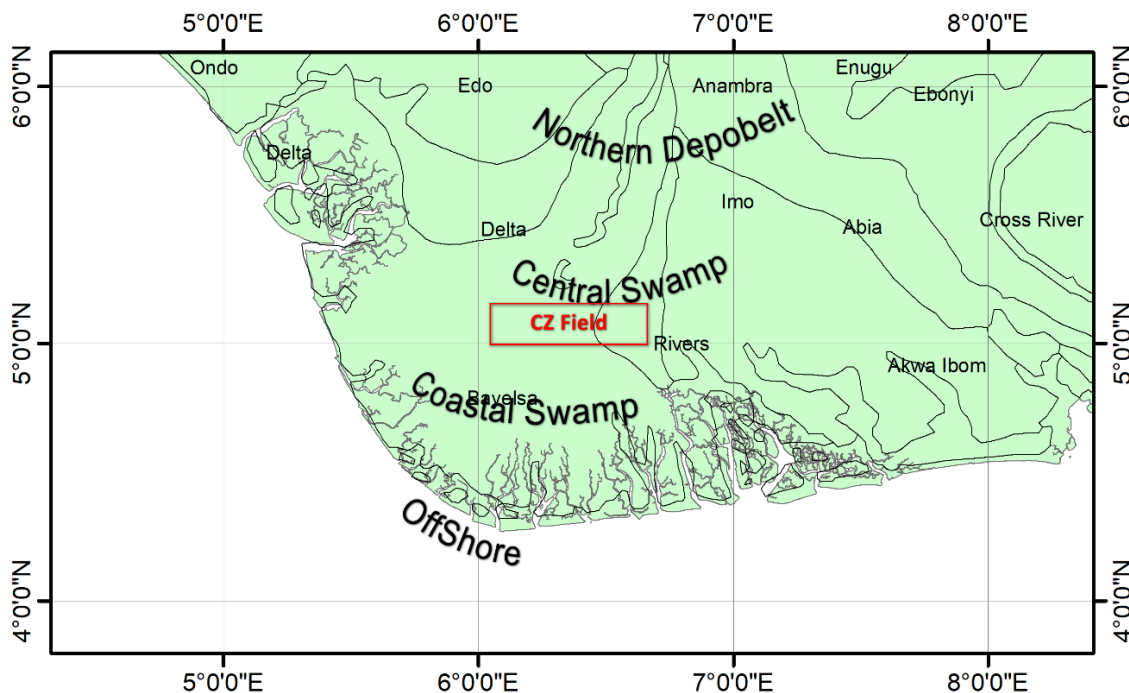


Figure 1: The "CZ field" is located in the Niger Delta as seen on the map

The Niger Delta is made up of three major layers: the upper Benin Formations, the lower Akata, and the middle Agbada. The Benin Formation, which ranges from the Miocene to the Recent, has been recognised as both the most recent and the earliest in its geological environment (Igboekwe et al., 2021). The southern coastal area, the Niger Delta complex, and non-marine sandstone deposits are also under investigation. It is situated in a river and continental environment. It is frequently associated with low levels of hydrocarbon accumulation (Akanji et al., 2018). The thickness of this Formation varies greatly, occasionally exceeding a value of 1820 m. The lower Agbada Formation is located under the upper Agbada Formation, a notable geological formation that spans the Eocene to Pliocene epochs and is principally known for its vast petroleum resources. This organism has been observed in a variety of settings, including fluvial and brackish coastal habitats. The proportions of shale and sandstone in the lower layers are usually equal, while the highest layer has a larger concentration of sand particles. Furthermore, inside the lowermost strata, the unconsolidated to slightly consolidated sandstones with a well-graded texture and varied degrees of roundness undergo a sluggish transition into shales.

Hydrocarbons are held inside sand formations, which act as reservoirs, and are successfully confined and sealed by shale formations, according to the results of (Corredor et al., 2005; Adeoti et al., 2014). The Akata Formation, a significant marine deposit that dates from the Eocene to the Recent epoch, with a thickness of nearly 7000 m. It resembles a diapir and shows apparent traces of significant overburden pressure, possibly emanating from the offshore continental slope. A significant geological sequence composed of shale, turbidites, and modest quantities of clay and silt has the potential to function as a hydrocarbon reservoir. According to Haack et al. (2000), the shales in issue also contain sandstones and siltstones in isolated locations.

Ridges, rollover anticlines, shale dippers, and growth faults are among the geological characteristics found in the Niger Delta region. These faults run northeast to southwest and northwest to southeast and can be classified as listric, crestal, antithetic, regional, or flank faults (Inyang et al., 2022). Furthermore, these faults are important in the production of many structural characteristics in the region (Oyanyan et al., 2020). The Niger Delta region is made up of depobelts and megaunits, which are important in geology, hydrocarbon distribution, and structural development. The relationship between sediment sinking rate and supply is tightly tied to the construction and design of individual mega units.

3. MATERIALS AND METHODS

3.1 Data Sets

The datasets used in this study include information about well heads and variations, as well as composite log suites gathered from 11 wells in the Greater Ughelli depobelt's "CZ" Field. Several logging techniques were used on the wells, including gamma ray, resistivity, neutron, acoustic, and density logs. Biostratigraphic markers, a 3D seismic volume containing the intended research area, and checkshot data were also used. CZ_01, CZ_02, CZ_03, CZ_04, CZ_05, CZ_06, CZ_07, CZ_08, CZ_09, CZ_10, and CZ_11 are the names of the wells. Total Producing Nigeria, in partnership with the Department of Petroleum Resources in Port Harcourt, made the dataset public.

The data acquired in the field was thoroughly evaluated and interpreted utilising a multidisciplinary approach. This method included defining the underlying geological formations and identifying areas prone to sand buildup that might possibly serve as hydrocarbon reserves.

The study's findings show that the CZ Field has good possibilities as a significant hydrocarbon producer. The study used a multidisciplinary technique that proved effective in determining the underlying structures and locating places prone to sand buildup that might possibly host hydrocarbon resources. The following stages of this research project will involve the execution of further drilling operations inside the selected region to confirm the presence of hydrocarbon deposits and determine the size of the reservoir.

3.2 Well Log Correlation

The biomarker data from well CZ_11 was used to build correlations between the wells and identify the significant reservoirs and sands. This information was then used to assess the potential reserves in the area. The ability to identify reservoir sand units in true vertical depth subsea (TVDSS) aided in the understanding of maximum flooding surfaces and sequence boundaries. The biostratigraphic report was used to determine the relationship between the marker shales. Check shot data was used to accomplish temporal and geographical alignment of the well data and seismic data (Okoli et al., 2021). This approach was also used for converting interpreted faults and horizon depths.

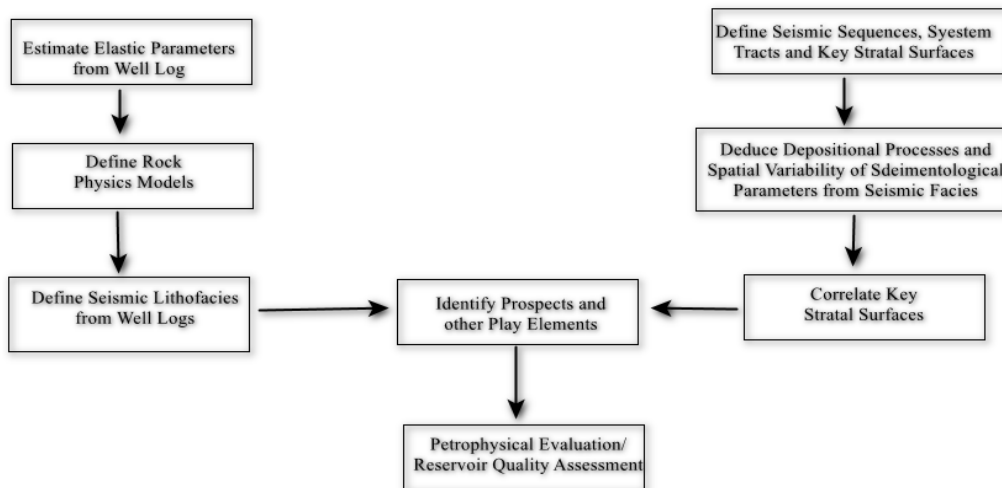


Figure 2: Workflow to integrate rock physics and seismic stratigraphy

3.3 Well-To-Seismic Tie

The process of "well to seismic tie" was employed to establish a correlation between the depth-domain wells and the time-domain seismic data. In order to accomplish this task, a synthetic seismogram, commonly referred to as a synthetic, was formulated by combining the wavelet obtained from seismic data with reflectance values computed from digitised density and acoustic logs (Okoli et al., 2021). The data's interpretive quality can be enhanced by the utilisation of well logs, which provide additional correlation points and markers for comparison with prominent reflections observed on the seismic section.

Seismic data is commonly acquired and documented in the time domain, whereas well data is normally acquired and documented in the depth domain (Chikezie et al., 2022). In order to present a seismic segment with a directed well projection, it is necessary to convert either the seismic data or the well data into depth or time domain. In both cases, the velocity plays a crucial role in the conversion process. The process of seismic conversion is a laborious undertaking that necessitates precise velocity data. As a result of this, interpreters opt to transform well data into temporal units and establish a correlation with seismic data. The majority of interpretation software comprises several tools designed to assist in the process of conversion.

To identify seismic reflections that correspond to potentially significant sand reservoirs, it is necessary to establish a connection between well data and seismic data. In order to enhance the correlation between seismic and well data, the data obtained from readily available check shots were integrated with the synthetic seismogram. The use of synthetic seismograms facilitated the establishment of a well-to-seismic correlation, serving as the preliminary stage in the identification of activities pertaining to the interpretable sand tops (Okoli et al., 2021). The inclusion of this hyperlink has enhanced the reliability of the horizon mapping process by utilising selected instances.

3.4 The Interpretation Of Structures

An examination of the seismic and structural data of the "CZ" field along both its dip and strike orientations were done to gain a knowledge of the subsurface's structural designs and depositional geometry. It is clear that fault and horizon maps have been included. These tools were used to document structural patterns and exercise power over the sediment supply rate and deposition regions caused by fault displacement. The genetic unit is constrained by the chosen horizons, which contain extensive vertical and lateral reservoir units.

3.5 Analysis Of The Biostratigraphy

Biostratigraphy serves as the fundamental framework for all sequence stratigraphic interpretations. The biostratigraphic data from the CZ_11 well in the research region was utilised in our interpretative analysis of seismic sequence stratigraphy. This data facilitated the identification of correct correlations within the well field by employing the stratal surface. To establish a comprehensive understanding of genetic sequences and their associated depositional settings, it is necessary to construct a chronostratigraphic framework. This framework is then utilised to analyse further field wells, employing the interpreted maximum flooding surfaces (MFSs) and sequence boundaries (SBs) (Okoli et al., 2021).

3.6 Analysis Of Seismic Sequences

The identification of discontinuity surfaces is required for the study of seismic sequences because it allows the identification of important reflection "packages." According to Octavian et al. (2010), discontinuities may be identified by examining the regular reflection termination patterns seen on the discontinuity surfaces.

Seismic facies assessment, seismic sequence evaluation, and interpretation of lithofacies and depositional contexts are the three key processes in understanding stratigraphy from seismic data.

3.7 Petrophysical Parameters Estimation

To comprehend the distributions of these characteristics throughout the field, well logs were used to calculate petrophysical variables such as effective porosity (ϕ_e), net-to-gross ratio (NTG), water saturation (S_w), and volume of shale (V_{sh}). Prior to that, the well data utilized in this study underwent a thorough quality check and control process. Where necessary, changes were then made.

Using petrophysical analysis, trends in shale, sand-clay and clean sand, and interested reservoir sands that have been chosen, the clay volume, water saturation parameters, porosity and net-to-gross were then calculated (Nwokoma et al., 2022). The resulting values were distributed over the full research region using modeling.

For petrophysical computations, the aforementioned equations were employed:

$$\phi_{den} = \frac{(\rho_m - \rho_b)}{(\rho_m - \rho_f)} \quad 1$$

where ϕ_{den} is density-derived porosity, ρ_m is the matrix density, ρ_b is bulk density, ρ_f is fluid density

This formula was used to determine each reservoir's overall porosity.

The volume of shale, which is the percentage of shale contained in a sandstone or heterolithic reservoir, was calculated using the following algorithm:

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

where I_{GR} is the gamma ray index and its formula is:

$$I_{GR} = \frac{(GR_{log} - GR_{min})}{(GR_{max} - GR_{min})} \quad 3$$

The gamma ray log, which yields the maximum and minimum gamma ray values, is a prerequisite for this procedure.

The formation's water saturation was initially estimated using Archie's equation for water saturation, which is provided as, in order to determine the fluid content's saturation of the reservoir sands:

$$S_w = \left(\frac{FR_w}{R_t} \right)^{\frac{1}{n}} \quad 4$$

where R_w is the formation's water resistivity, F is the formation factor; R_i is the genuine rock resistivity (i.e. the resistance of the untouched area) and n is the saturation exponent (typically 2). The Humble's formula for unconsolidated sands, which is as follows, was employed to establish the formation factor:

$$F = \frac{0.62}{\phi^{2.15}} \tag{5}$$

where 0.62 serves as a constant for the tortuosity factor and was employed in this approach for the Niger delta's unconsolidated Tertiary rocks.

The ratio of the thickness of the clean, porous, and productive (Net) reservoir sand to the total (Gross) thickness of the reservoir was calculated using the Net-to-Gross (NTG) technique:

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

The ratio of the thickness of the clean, porous, and productive (Net) reservoir sand to the total (Gross) thickness of the reservoir was calculated using the Net-to-Gross (NTG) technique. Equation below was used to determine effective porosity:

$$\phi_e = (1 - V_{sh})\phi_{den} \tag{7}$$

3.8 Seismic Lithofacies Definition And Fluid Substitution

Seismic lithofacies are sedimentary units on a seismic scale that may be distinguished by their unique petrophysical properties. According to Avseth (2005), various characteristics contribute to clay characterisation, including its quantity, bedding type (massive or interbedded), particle size, cementation, density, and seismic velocities. Seismic data were used to quantify the facies and fluid characteristics. The utilisation of a complete suite of dependable logs that reached the subsurface and gathered samples from the majority, if not all, of the major lithologies resulted in the identification of a substantial well (Onyekuru et al., 2022). The utilisation of well logs is critical in creating a link between the detailed seismic data and the rock formation features.

4. RESULTS AND FINDINGS

4.1 Estimated In-Place Hydrocarbon Volumes

Volumetric techniques attempt to estimate the amount of oil in a reservoir by taking into account both its dimensions and the physical qualities of its

fluids and rocks. Following that, a recovery factor (RF) is computed using ideas developed from fields with similar features. To calculate the reserves, execute a multiplication operation with the beginning quantity of gas or oil and the recovery factor, which is indicated as STOIIP for gas and GIIP for oil. Recovery factors for solution gas drive and gas cap drive in gas cap fields, such as the "CZ" field, as well as saturated reservoirs with water drive, are frequently in the 15% to 25% range. Until other production procedures within the corresponding area are established, this first estimation typically acts as the principal assessment for a unique discovery (Sandrea and Sandrea, 2007).

Using a simple average weighted calculation that includes the key oil producing locations, an average recovery factor of 22% can be determined, which is well within the range of the reservoirs. In terms of the solution gas driving mechanism. According to a comparative investigation, the global recovery factor for the majority of conventional oil reserves globally is expected to be no more than 20%. Sandrea and Sandrea (2007) used a recovery ratio of 20% for oil and 80% for gas in their investigation.

The formulas below might be used to calculate the oil reserve and gas reserve:

$$\text{Oil Reserve} = \left(\frac{7758 \times A \times h \times S_o \times \phi}{B_o} \right) \times \text{RF} \tag{8}$$

$$\text{Gas Reserve} = \left(\frac{43560 \times A \times h \times S_g \times \phi}{B_g} \right) \times \text{RF} \tag{9}$$

Where: 7758 = factor for converting an acre-foot to a barrel, 43560 is Conversion from acre-ft to ft³ factor, ϕ is average reservoir effective porosity (fractional), h_{is} reservoir's net thickness, A_{is} Area of the field, B_o is Formation oil volume factor = 1.2 bbls/STB, S_o is oil saturation on average (fractional), B_g is Formation gas volume factor = 0.005 cuft/scf, S_g is fractional (gas) saturation with hydrocarbons, RF is Recovery factor (fractional).

The reserve of field gas has an estimated area of 240km², or 1245.40 acres, as determined by seismic data. Table 1 makes it clear that the three reservoir zones contain significant amounts of hydrocarbon, sufficient to support a positive commercial conclusion. The number of hydrocarbons present in the reservoir sands under investigation was the goal of every approach utilized in this investigation. A summary of the estimated in-place volumes in the analyzed reservoir sands of oil and gas is presented in table 1 below.

Table 1: For the Two Reservoirs, a Hydrocarbon Volume Calculation Summary Report Sheet

Reservoir		STOIIP (Mbbbl)	STGIIP (Bcf)	Recoverable Oil@20% (Mbbbl)	Recoverable Gas@ 80% (Bcf)
Thin Sand		-	10.4	-	8.3
Sand B	Zone 1	-	30.6	-	24.5
	Zone 2	46.8	-	9.4	-

5. DISCUSSIONS

The petrophysical evaluation, rock physics modelling, synthetic seismic generation, sequence stratigraphy, time to depth calibration, reservoir identification, and prospects projection in this work were all conducted using well log data, which is widely acknowledged as the most dependable data source in the industry.

Lithofacies were discerned from well logs by extrapolating the physical requirements derived from gamma ray and resistivity log responses. Shales, also known as clay minerals, exhibit relatively strong gamma radioactive reactions, rendering them useful markers of grain size. The gamma ray log is utilised to monitor the levels of radioactivity in geological formations. Therefore, the estimation of depositional energy may be deduced by the use of logarithmic analysis. Sand particles with a larger grain size have a lower gamma ray value, resulting in a reduced quantity compared to mud samples with a higher gamma ray signal. The measurement of gamma ray levels in units is conducted by the American Petroleum Institute (API), whereby anhydrite exhibits a very low number of units, whereas shales demonstrate an excess of 200 API units. In the study region, the differentiation between reservoir sands and non-reservoir shales was achieved by the use of gamma ray log patterns.

The correlation analysis conducted in this study demonstrated a limited sand reservoir interval throughout the eleven wells that were studied. The considerable rock physics feature and the observed high resistivity kick during that period provided evidence for this assertion. The low porosity

zone perhaps constitutes a component of the transgression sands observed within the paralic Agbada Formation's shale stages.

The use of the biostratigraphic report, namely the Maximum Flooding Surfaces (MFSs) and Sequence Boundaries (SBs), obtained from well CZ 11, facilitated the ease of interpreting the well log data through the application of sequence stratigraphy. The dissemination of these organisms extended to additional wells within the designated research area.

The 23.2 million years ago (Ma), 28.7 Ma, and 31.3 Ma maximum flooding surfaces (MFSs) serve as the primary stratal boundaries employed for well correlation purposes. The correlation surfaces known as the 23.7 million years ago (Ma), 29.3 Ma, and 37.4 Ma SBs are included as part of the supplementary set. Two genetic sequences were obtained from the markers shales of the Maximum Flooding Surfaces (MFS), as per Galloway's (1989) concept. The markers exhibited a significant correlation over the whole well-field. Based on the available stratigraphic data sheet pertaining to the Niger Delta, it can be inferred that the clastic sediments within the designated research area exhibit an age range spanning from the Oligocene epoch to the early Miocene epoch. This conclusion is drawn from the established dates of the sequence boundaries (SBs) and maximum flooding surfaces (MFSs).

The determination of the depositional environment for the relevant units may be deduced from the analysis of grain size using gamma log data and the identification of depositional systems based on stacking patterns. The

isochore maps generated from the well tops in the field provided visual representations of the accurate vertical thicknesses of the penetrated formations, as well as the orientation of the depositional axis. The axes of depo-tendency exhibited a consistent northeast to southwest orientation, mirroring the path of sediment influx into the Niger Delta Basin.

5.1 Structural Styles In "CZ" Field

The study faults, which include both regional and local scales, are critical in defining the principal reservoir compartments and petroleum traps within the examined area. The existence of fractures and flexures within reservoir beds and other geological layers can be linked to the creation of these structural traps. A sealing effect is required to prevent fluid passage via the fault plane, therefore protecting the reservoir rocks. The Niger Delta Basin's hydrocarbon exploration operations have mostly focused on the discovery and characterisation of structural traps, which may be found using both surface measurements and seismic analysis. The utilisation of growth structures and four-way dip closures has been

critical in identifying around 75% of the world's huge oil reserves.

Growth faults have the ability to form inside rapidly deposited sediments, particularly in deltaic settings. Sedimentation causes syndepositional faulting, which causes an imbalance in the thickness of related strata. Specifically, the strata on the downthrown side are thicker than those on the upthrown side. Vertical displacement between equivalent strata reduces with increasing elevation over the fault line. The strata that cross the major fault plane are more likely to generate subsidiary fault planes with opposing displacement, which are frequently referred to as antithetic faults. It is usual custom to impede the fault plane in order to avoid further escalation of oil and gas. The displacement of sandstone strata away from the fault plane may result in the construction of fault traps. Nonetheless, particular petroleum traps occur within "roll-over" anticlines in the down-faulted block. Growth faults in sedimentary basins have the ability to impede pore-water flow owing to compaction, resulting in the creation of clay dippers, which are frequently linked with these growth faults.

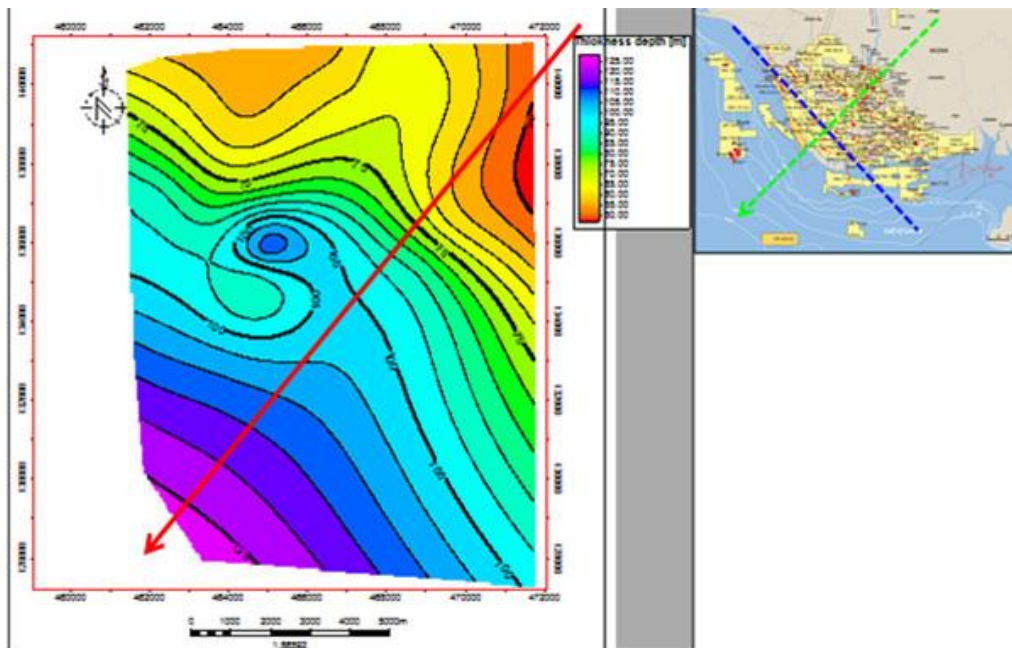


Figure 3: Isochore map generated from Well-tops. Arrow points to the depo-axis direction

Figure 3 depicts the configuration of growth faults F2, F3, F5, and F6, which have varied orientations. The two principal growth faults, F3 and F5, are large in size and have a south-westward dip. The defect F6 has a splay (branched) feature, whereas the alternative defect F2 is classified as

an antithetic imperfection and is of moderate severity. This model adds to the data gathered from the variance map generated from the 2000ms time slice shown in the top right corner of Figure 4.

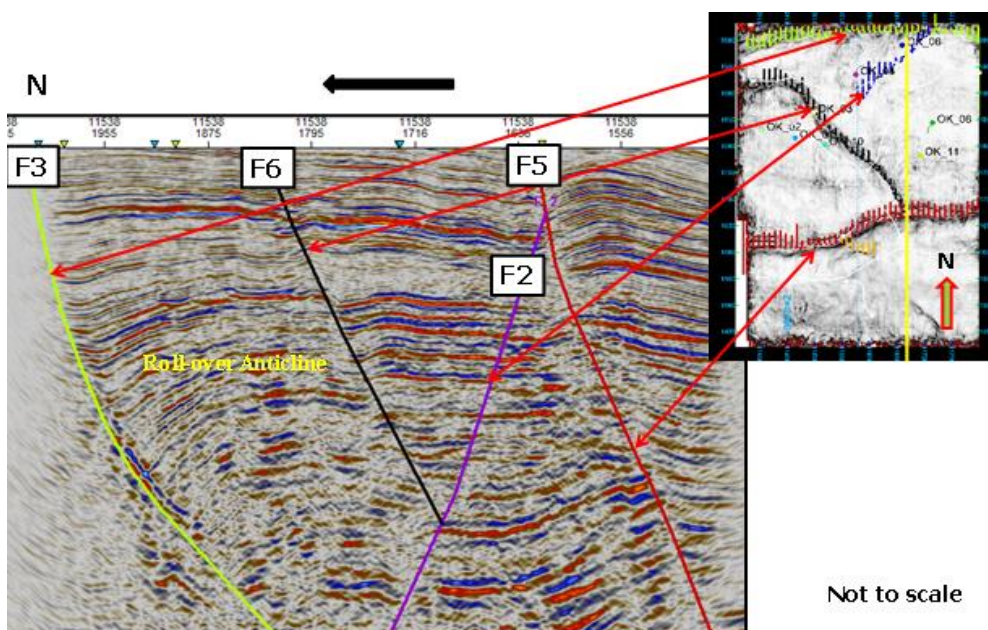


Figure 4: The mapped growth faults and roll-over structures are displayed in line 11538. F3 and F5 are structure building faults; F6 is a splay fault; F2 is an antithetic fault

5.2 Play Elements And Prospect Prediction

The dynamic interplay of a producible reservoir, a petroleum charge system, a regional topseal, and traps in the formation of petroleum accumulations within a certain stratigraphic level is explored in the play. To properly predict the presence of source rocks, reservoirs, topseals, and traps, a thorough understanding of the structural and stratigraphic development of the depositional phases occurring within a specific basin is required. The initial and pivotal phase in the development of geological models that underpin play evaluation is the accurate identification and interpretation of the fundamental tectonic and thermal processes that impacted basin formation, as well as the geometry and sedimentary facies within the basin-fill (Allen & Allen, 2005).

The basic goal of play element analysis is to provide a comprehensive categorization system that limits the varied range of geological and technical elements used in estimating undiscovered hydrocarbon reserves. According to Otis and Schneidermann (1997), the play is the most important component of the hydrocarbon system, with the play elements being designated as the key play components. Many play factors and their sub-elements were studied, including seal type, source facies, reservoir facies, and reservoir quality and distribution.

Seismic properties and traditional well-log patterns in the reservoir were used to identify depositional facies and ecosystems. A complete chronostratigraphic framework was used throughout the whole area by using maximum flooding surfaces as a primary reference. This method permitted the incorporation of stratigraphic units into genetically linked packages judged adequate for reservoir mapping. The development of a link between amplitude and lithology has proven useful for calibrating wells to seismic events and analysing regional stratigraphy. Sandstones commonly have large seismic amplitudes, whereas Shaley units typically have small seismic amplitudes.

The presence of roll-over anticlinal structures and growth faults within the studied area indicates considerable structural deformations. When the seal integrity of roll-over anticlines is not compromised, these geological formations serve as ideal traps for hydrocarbon resource accumulation. Furthermore, the Agbada Formation, which is located

within the selected research region, has stratigraphic traps and sealing faults. Because of these geological characteristics, permeable reservoir sands and impenetrable shaley strata coexist.

The source facies are the precise sedimentary habitat or depositional context from which a certain sediment or rock formed. According to Weber and Daukoru (1975), the principal source rock within the Akata Formation is shale intervals. According to Kouadio et al. (2020), these intervals also get contributions from the Agbada Formation's organic-rich shale sections. The principal source facies were identified through the use of well logs and seismic facies research. Because the source rocks are thought to be present across the field, the thermal maturity, availability of source material, and quality of the source rocks are typically regarded suitable for the creation and release of hydrocarbons over the whole field.

5.3 Prospect Prediction

Certain geological elements must be in sync for the growth and accumulation of petroleum in a specific place. These include the following:

There is a rock reservoir in the region that serves as a petroleum gathering station.

The petroleum resource has been entrapped and is now being kept in a reservoir.

A nearby source rock contains organic stuff that, given the right temperature and pressure circumstances, has the potential to be converted into petroleum. To expedite the movement of petroleum from its source to the reservoir rock, a conduit must be built.

It is unusual for these components to exist at the same time. The lack of one or more oil and gas buildups in the surrounding area rules out their presence. In this paragraph, the phrase "prospect" refers to a noticeable prospective petroleum resource. This research combined well data from an active producing well in the onshore Niger Delta Petroleum Province with seismic survey data collected around the boundaries of the Greater Ughelli Depobelt.

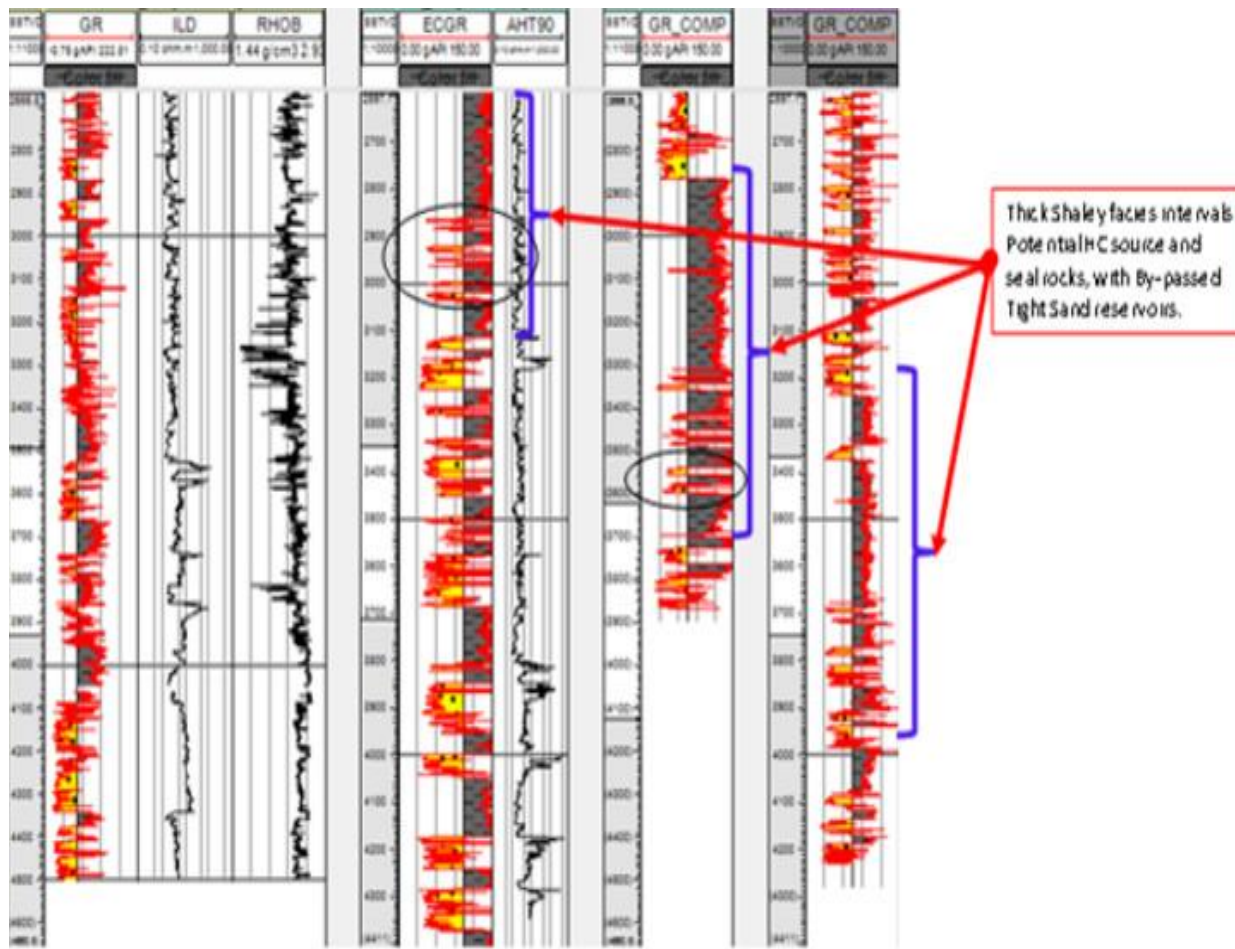


Figure 5: Source and seal facies identified from well logs

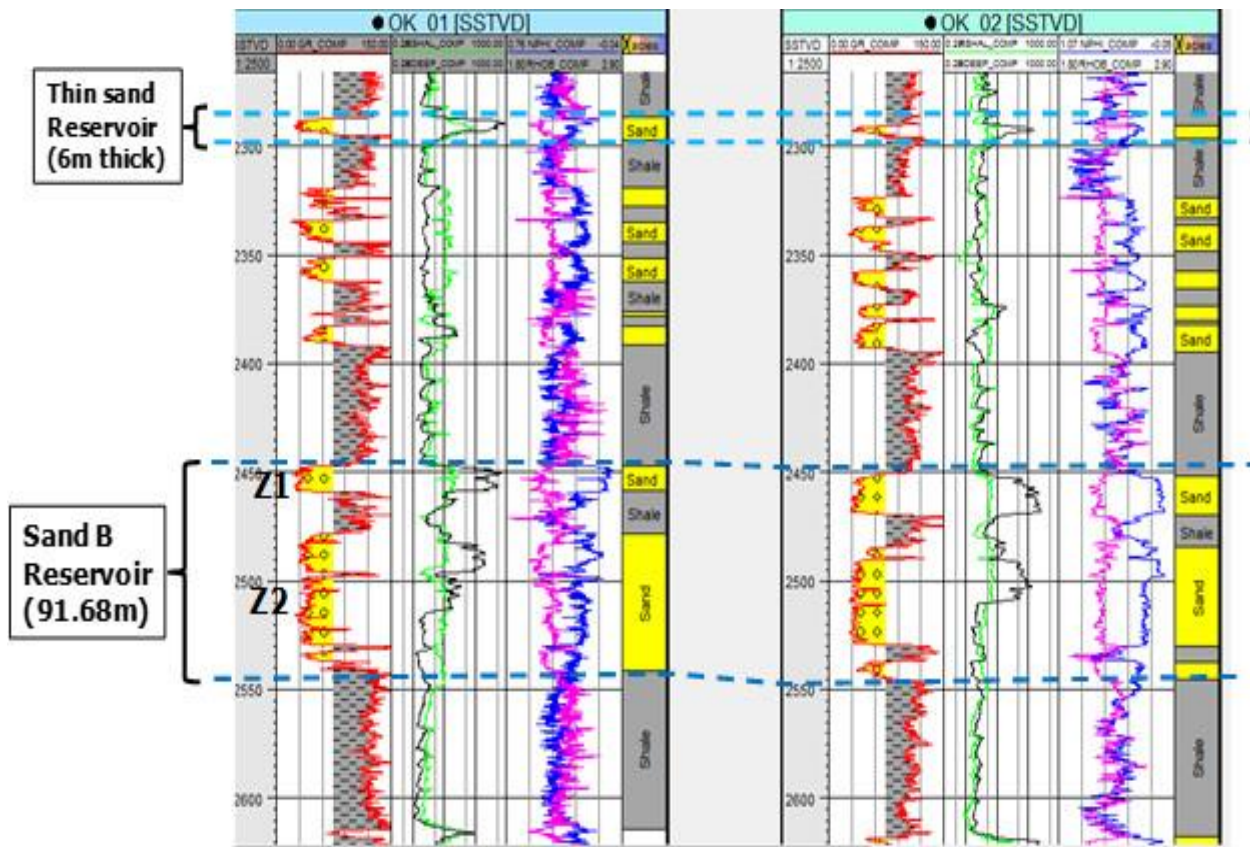


Figure 6: Predicted from well logs are potential hydrocarbon possibilities in the research area.

The hydrocarbon fluid types in these reservoirs were assessed utilising a mix of shallow and deep resistivity log readings, as well as the detection of a "gas-effect" using density and neutron logs. This method allows for a

quick examination of the reservoir sands. The existence of gas is visible in the thin reservoir sand and the upper zone (Z1) of the Sand B reservoir, but oil is discovered in the bottom zone of the Sand B reservoir.

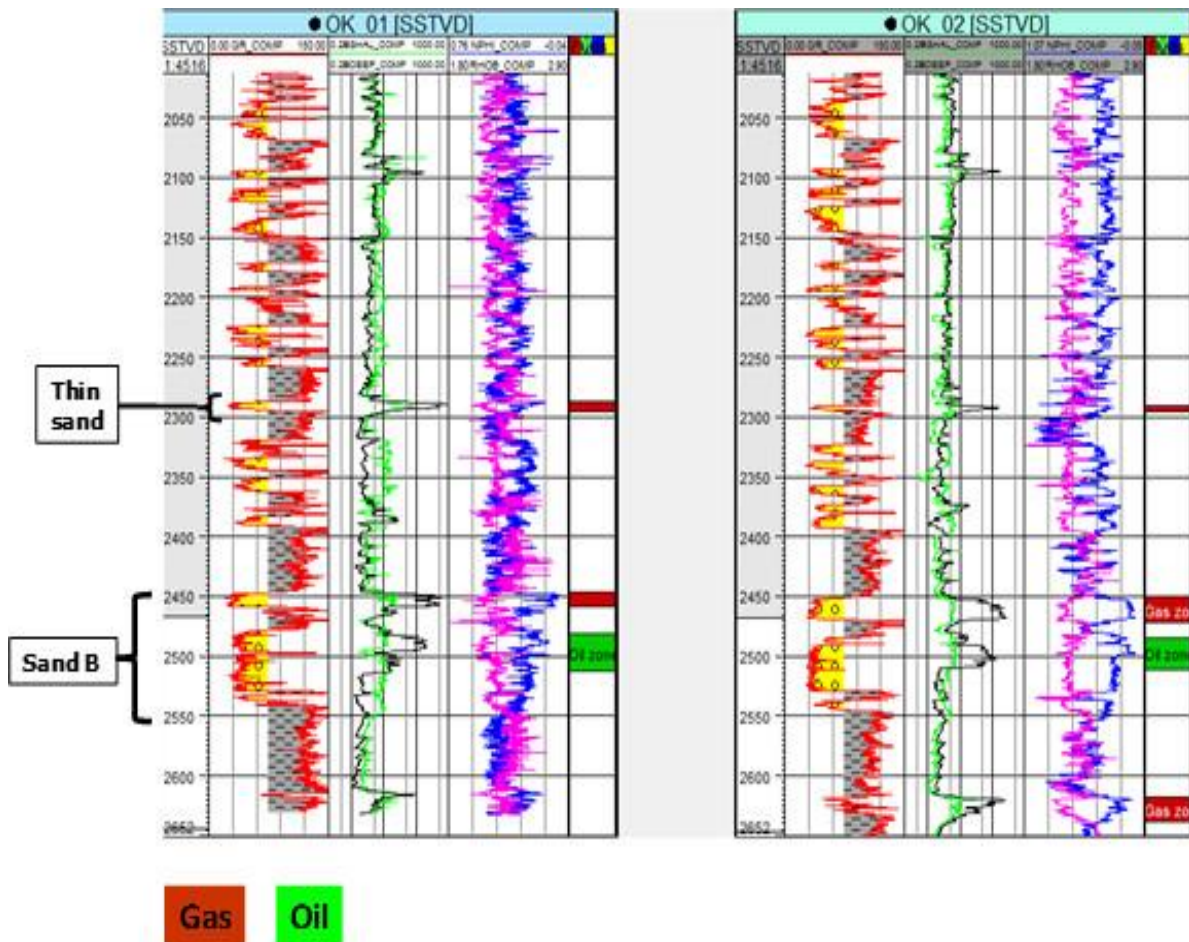


Figure 7: Types of hydrocarbons found in the reservoir target sands

5.4 Reservoir Quality Assessment

The quality of reservoirs can vary significantly at the microscopic level. The evaluation of reservoir rock quality in terms of fluid transport and retention capacity is based on two important parameters: porosity, which measures fluid retention capacity, and permeability, which measures fluid transfer capacity. The dynamics of fluid flow, distribution, and storage within a reservoir are heavily influenced by reservoir quality. Porosity and permeability are important factors that may be effectively analysed by examining rock samples collected from well logs. Flow units can be derived from a variety of petrophysical and geological criteria; however, the three most important factors—porosity, permeability, and thickness—are typically gathered and used to assess the capacity of flow units to store and transfer fluids within a reservoir.

Throughout the Cenozoic age, the Niger Delta area has had a considerable amount of sand within its geological structure. Reservoir extension is usually inhibited during the paralic section's sandy regressive offlap phases, especially when reservoirs are strategically linked with intraformational seals. The depositional environment and depth at which sand reservoirs originate have a substantial influence on their quality in paralic sequences. The construction of multiple reservoirs in the Niger Delta area can be linked to the development of either a single barrier bar or a point bar. Reservoir sands with thicknesses greater than 15 metres are frequently made of composite deposits in the majority of geographical locations. These formations are made up of multiple layers of sand produced from similar or dissimilar sedimentary settings. Stacking of two or three barrier bars is common in the absence of considerable marine shale deposition. Oil-bearing reservoirs can have porosities of up to 40% and are marked by insufficient consolidation. According to Ehrenberg et al. (2009), porosity decreases steadily with increasing depth.

Reservoirs have a wide range of lateral variety. A barrier bar is frequently pierced by a distributary channel fill at the same stratigraphic level. Larger fields have higher lateral heterogeneity because the variations in the depositional environment from one cycle to the next in regard to the shoreline location are more noticeable.

Because of the delicate interplay between diagenesis and primary depositional variations in environment and texture, a thorough understanding of the processes that regulate and distribute reservoir quality is critical in the context of tight-gas reservoirs. These interactions have a significant influence on pore networks, rock mechanical characteristics, and natural fracture occurrence. The permeability and porosity of a reservoir both impact its quality. The quality of reservoirs in tight-gas sandstones is determined by both the initial sediment composition and subsequent modifications. Fracture, cement deposition and dissolution, as well as physical and chemical compaction, are all common mechanisms of modification.

The clastic rocks, notably sands, dominate the lithological makeup of the petroleum reserves in the examined region. Because of their poor effective porosity and permeability, which limit fluid flow in both horizontal and vertical directions, the Shaley facies or clay layers are considered unsatisfactory reservoir rocks. The presence of a sandstone matrix frequently inhibits the reservoir's ability to develop. By evaluating its reaction to the presence of clay minerals, the gamma ray log was used as a substitute for core and thin-section data to derive the grain sizes of the sediments in the research region.

These sands' effective porosity values vary from 21% to over 28%, which corresponds to the usual porosity oscillations reported in the Niger Delta. This finding is based on a petrophysical examination of the indicated reservoir zones. Depending on the exact deposition environment, the reservoirs in issue range in quality from acceptable to extraordinary. The shoreface beach deposits and tidal channel sands are particularly remarkable among the many reservoir types discovered in the "CZ" field, as indicated by the study of the studied wells, due to their advantageous reservoir quality and geometry.

Rider (2002) performed research in which the permeabilities and porosities of reservoirs were qualitatively analysed. This conclusion implies that the reservoirs' water saturation is extremely low. This finding implies that the reservoirs in issue have high levels of hydrocarbon saturation and a large capability for hydrocarbon production. The terms porosity and permeability are frequently used interchangeably, with clastic rocks acting as an excellent example. The reservoirs studied have high effective porosity values, demonstrating their permeability and interconnectivity for fluid transmission.

6. CONCLUSION

The present study employed rock physics and seismic stratigraphic methodologies to provide a quantitative prediction of potential petroleum play features and opportunities inside the "CZ" Field, located in the Greater Ughelli Depobelt. The investigation integrated well logs, seismic volume, and biostratigraphic data in order to ascertain the variables that govern reservoir quality and seismic signatures within the designated research region.

The well log data was used to identify two reservoir sand masses by lithological correlation. The reservoirs in question are often known as the "Thin Sand" and "Sand B" reservoirs. The reservoirs exhibit discernible variations in their petrophysical and elastic characteristics.

The principal growth faults and antithetic faults displayed on the structural map of the field were identified via the use of well log data and seismic analysis. The subsurface reservoir trapping mechanism in the region may be attributed to the presence of an anticlinal structure that is supported by faults. Nevertheless, there was a lack of generated structural maps to provide evidence for this claim.

The sequence stratigraphic architecture of the "CZ" Field in the Niger Delta was determined by integrating seismic and biostratigraphic data with well log responses, namely gamma-ray and resistivity logs. The identification of sequences and system tracts was accomplished by the utilisation of well log data to analyse stacking patterns. The identification of sequence boundaries was conducted by locating the inflection points of the lowstand prograding complexes and the parasequences inside a sand unit that exhibits a shallowing upward trend, transitioning from progradation to retrogradation, known as the lowstand systems tract. The dataset exhibiting the highest gamma-ray intensity and the lowest resistivity values was employed to ascertain the greatest flooding surfaces. Subsequently, these surfaces were corroborated by the utilisation of biostratigraphic data. An effort was undertaken to conduct a sequence-stratigraphic analysis of the well by considering the occurrence of a limited number of chosen indicator fossils.

The temporal scope of the study encompassed the Oligocene epoch to the Early Miocene epoch. The seismic data was utilised to map two genetic sequences, and their respective stacking patterns of systems tracts were determined using Galloway's (1989) stratigraphic model. The interpretation of the geologic dates of the sequence boundaries (SBs) indicates that they span from 23.7 Ma for sequence I, 29.3 Ma for sequence II, and 32.4 Ma for sequence III. Similarly, the maximum flooding surfaces (MFSs) are located at around 23.2 Ma, 28.7 Ma, and 31.3 Ma for the corresponding sequences. The sediments observed within the research region are indicative of the sedimentary facies associated with the Greater Ughelli depobelt.

The analysis focused on the petrophysical features of the sand reservoir units that were found. The effective porosities and net-to-gross ratios of the Sand B reservoir exhibit a range of 21% to 28%, but the Thin Sand reservoir has a wider range of 23% to 79%. The net-to-gross ratios seen in the Sand B reservoir exhibit a range of 79% to 86%, whereas the Thin Sand reservoir has a consistent ratio of 79%. The petrophysical and elastic parameters were determined by use the Thomas-Stieber and modified lower Hashim-Shtrikman models.

Four seismic lithofacies were discerned by the use of crossplots of elastic properties, namely sands, shaly sands, heteroliths, and shales. These findings were also identified by means of analysing seismic facies and well data. The clastic sediments in the research region were interpreted to have been deposited in fluvio-deltaic or shallow marine shelf environments, based on the available evidence.

The petrophysical analysis of fluid typing revealed that the Thin Sand reservoir had gas characteristics, whereas the Sand B reservoir exhibited gas properties in the top zone and oil properties in the bottom zone. The volumetric evaluations conducted on the in-situ hydrocarbons have indicated that these reservoirs contain substantial quantities of oil and gas that have significant economic value, hence enabling informed and prudent commercial decision-making.

The present study, which employs seismic stratigraphy and rock physics methodologies, as well as the integration of well logs and biostratigraphic data, has yielded significant results on the CZ Field, which is located inside the Niger Delta Basin. Future exploration activities and decision-making processes will benefit from a better knowledge of possible hydrocarbon possibilities as a result of reservoir, structural, and sequence stratigraphic research.

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