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Reservoir Quality Evaluation Using Petrophysical Logs and Seismic Attribute Techniques: A Case Study of GOTO Field, Niger Delta Basin

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ABSTRACT

The 21st-century global energy demand necessitates advanced reservoir characterization to optimize hydrocarbon exploitation and minimize drilling risks. This study integrates petrophysical analysis and multi-attribute seismic interpretation to evaluate the hydrocarbon potential of the GOTO Field in the Niger Delta. Using suites of well logs from seven wells and 3D post-stack seismic data, four reservoir sands (A, B, C, and D) were delineated and correlated across the field. Petrophysical evaluation reveals that Sand A is the most prospective unit, exhibiting excellent reservoir quality with average effective porosity of 29.3%, permeability reaching 758 mD, and moderate water saturation. Sands C and D show moderate quality with localized potential, while Sand B is identified as predominantly water-saturated (91–96%). Seismic interpretation identified major structural traps, including rollover anticlines and fault-assisted closures. Analysis of seismic attributes—including RMS Amplitude, Average Energy, and Sweetness—revealed strong anomalies in Sands A, C, and D that conform to structural highs, serving as direct hydrocarbon indicators (DHIs). The high degree of consistency between petrophysical data and seismic attribute responses demonstrates that this integrated quantitative approach significantly reduces exploration uncertainty and improves the precision of reservoir evaluation in complex deltaic environments.

INTRODUCTION

The 21st century has seen an unprecedented global and local demand for energy driven by the needfor economic advancement and an improved standard of living. This growing demand has placed immense pressure on energy resources, particularly hydrocarbons, necessitating advanced and efficient methods of exploration and production. In Nigeria, oil constitutes the backbone of the national economy, making the effective and optimal exploitation of this non-renewable resource a critical priority for both government and research institutions.

Advancements in computational technology have significantly improved the ability to predict hydrocarbon presence with reduced risk. Seismic attributes and inversion techniques have emergedas powerful tools in the oil and gas industry, particularly in determining hydrocarbon potential.

These tools are vital for minimizing uncertainties in reservoir characterization, which is crucial for ensuring cost-effective field development and reducing drilling-associated risks. By integrating these methods, geoscientists can better evaluate potential prospects and optimize drilling locations in regions like the Niger Delta. The Niger Delta basin, a prolific oil province, is characterized by a complex stratigraphy of sand and shale formations. It hosts numerous reservoirs with varying petrophysical properties, making precision in reservoir evaluation critical. Conventional seismic interpretation techniques often leave uncertainties in identifying and delineating hydrocarbon reservoirs. However, the integration of seismic inversion with well log data and attributes provides a more robust framework, enabling the characterization of reservoir heterogeneity, fluid distribution, and hydrocarbon volume with higher accuracy.

Reservoir characterization is essential for understanding the properties and behavior of hydrocarbonreservoirs. It integrates geological, geophysical, petrophysical, and reservoir engineering data to build models that describe the reservoir's capacity to store and produce hydrocarbons. Recent studies in the Niger Delta emphasize the importance of combining structural interpretations with seismic inversion and well log analysis. Studies such as those by Aizebeokha and Olayinka (2011), Adetoye (2009), and Oyedele et al. (2020) have demonstrated the effectiveness of integrating these methods for accurate reservoir delineation in the Niger Delta region.

The seismic method, particularly reflection seismic, has proven to be the most effective tool in hydrocarbon exploration. Over the years, seismic interpretation has transitioned from a qualitative to a more quantitative approach. Techniques such as Amplitude Versus Offset (AVO) analysis, seismic attributes, acoustic and elastic impedance inversion, forward seismic modeling, and rock physics have become instrumental in providing geoscientists with critical insights into lithology, porosity, fluid properties, and saturation. These advancements enable geoscientists to evaluate prospects and delineate reservoirs with greater precision, leading to enhanced hydrocarbon recovery.

The digital revolution has significantly influenced geoscience, transforming it from a descriptive discipline into one heavily reliant on quantitative analysis. Advances in 3D seismic data and geophysical wireline log datasets allow for the application of probabilistic and statistical models toimprove exploration outcomes. The advent of big data and artificial intelligence (AI) has further revolutionized the field by enabling the extraction of patterns and predictions from large datasets. This approach is particularly beneficial in integrating diverse datasets, often referred to as "soft data," to create coherent and reliable subsurface models.

The GOTO Field in the Niger Delta presents a unique opportunity to explore the integration of quantitative seismic interpretation and well log analysis. By employing petrophysical analysis, seismic inversion, and AVO techniques, this study aims to minimize uncertainties in reservoir evaluation, enhance precision in hydrocarbon volume estimation, and improve drilling success rates by identifying optimal drilling locations. Recent studies within the Niger Delta highlight the use of lithologic and fluid discrimination to analyze delineated reservoirs, often through the incorporation of structural interpretation and inversion analysis. These approaches are essential for characterizinghard-to-image reservoirs, predicting interwell reservoir properties, and fine-tuning drilling locations.

Given the critical role of hydrocarbons in Nigeria's economy, this study seeks to advance scientific understanding and contribute to the sustainable and efficient exploitation of the country's energy resources. The task of minimizing pitfalls in quantitative reservoir assessment and evaluation is an integral aspect of any promising petroleum exploration project. The integration of seismic inversion and attributes has proven to be a reliable approach for effective delineation of reservoir characteristics, volume, and distribution in the Niger Delta region. As energy resources become scarcer and older fields mature, the need for accurate reservoir characterization and optimized production has never been greater, making this research both timely and critical.

Geology of the Niger Delta

The Niger Delta is ranked among the major prolific deltaic hydrocarbon provinces in the world and is the most significant in the West African continental margin. Oil and gas in the Niger Delta are principally produced from sandstones and unconsolidated sands predominantly in the Agbada formation. The goal of oil and gas exploration is to identify and delineate structural and stratigraphic traps suitable for economically exploitable accumulations and delineate the extent of discoveries in field appraisals and development (Aizebeokhai and Olayinka, 2011)

The Niger Delta, situated at the apex of the Gulf of Guinea on the west coast of Africa, covers an area of about 75 000 km^2 as shown in Figure1a. The Basement tectonics of the Niger delta related to crucial divergence and translation during the late Jurassic and Cretaceous continental rifting probably determined the original site of the main rivers that controlled the early development of the Delta. The Cenozoic development of the delta is also believed to have taken place under approximate isostatic equilibrium. The main depocenter is thought to have been at the triple junction between the continental and oceanic crust where the delta reached a main zone of crustal instability (Doust and Omatsola, 1990).

The Tertiary section of the Niger Delta is divided into three formations, representing prograding depositional facies that are distinguished mostly on the basis of sand-shale ratios. These are Akata, Agbada and Benin formations (Doust and Omatsola, 1990).

The Delta's sediments show an upward transition from marine pro-delta shales (Akata Formation) through a paralic interval (Agbada Formation) to a continental sequence (Benin Formation) as shown in Figure.1b. These three sedimentary Environments, typical of most deltaic environments, extend across the whole delta and ranges in age from early tertiary to resent (Murat, 1970). The Niger Delta is said to be formed at the site of a rift triple junction related to the opening of the southern Atlantic starting in the Late Jurassic and continuing into the Cretaceous (Adejobi *et al.,* 1997).

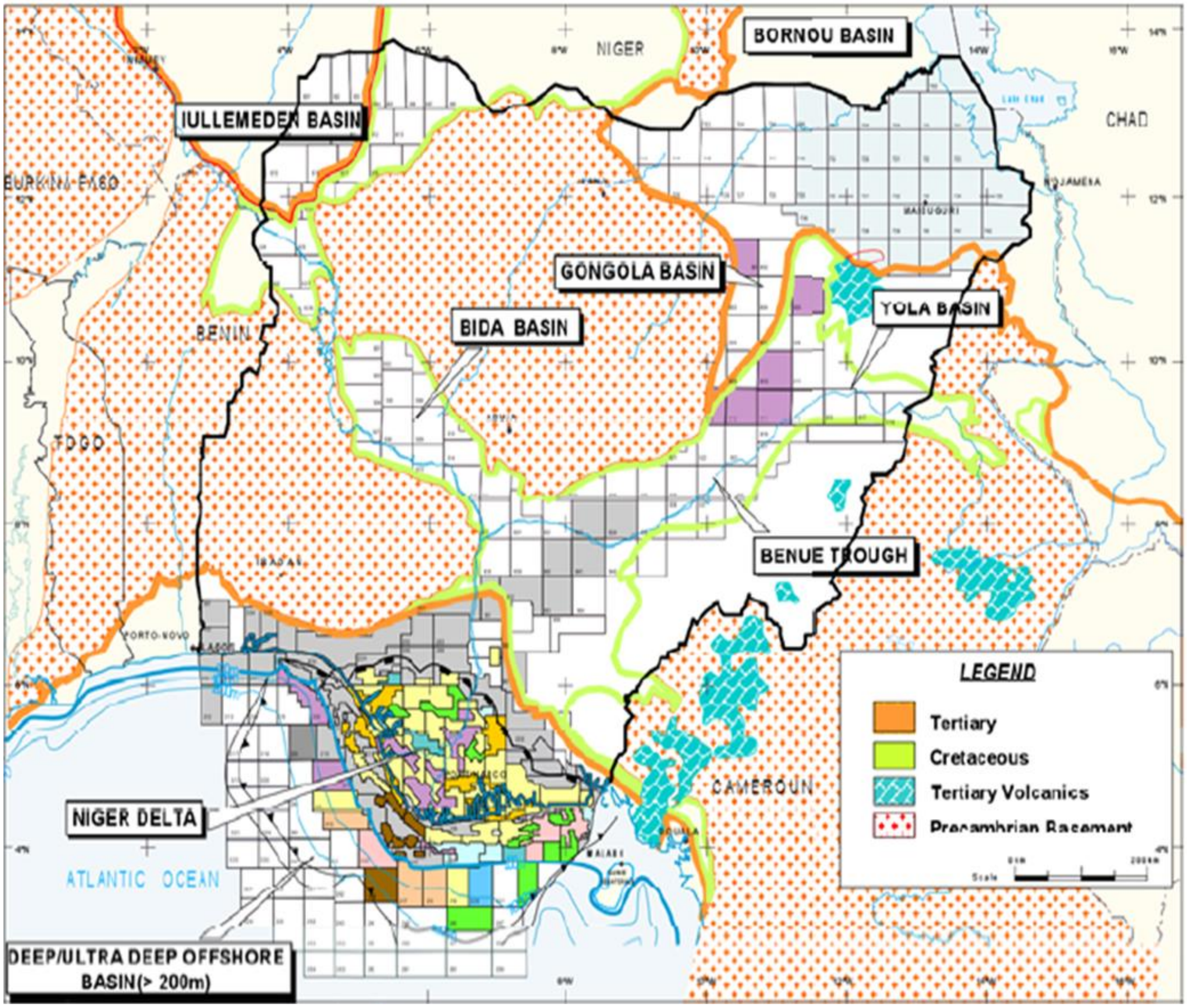

Figure 1a: Geological map of Nigeria showing the Niger Delta Basin

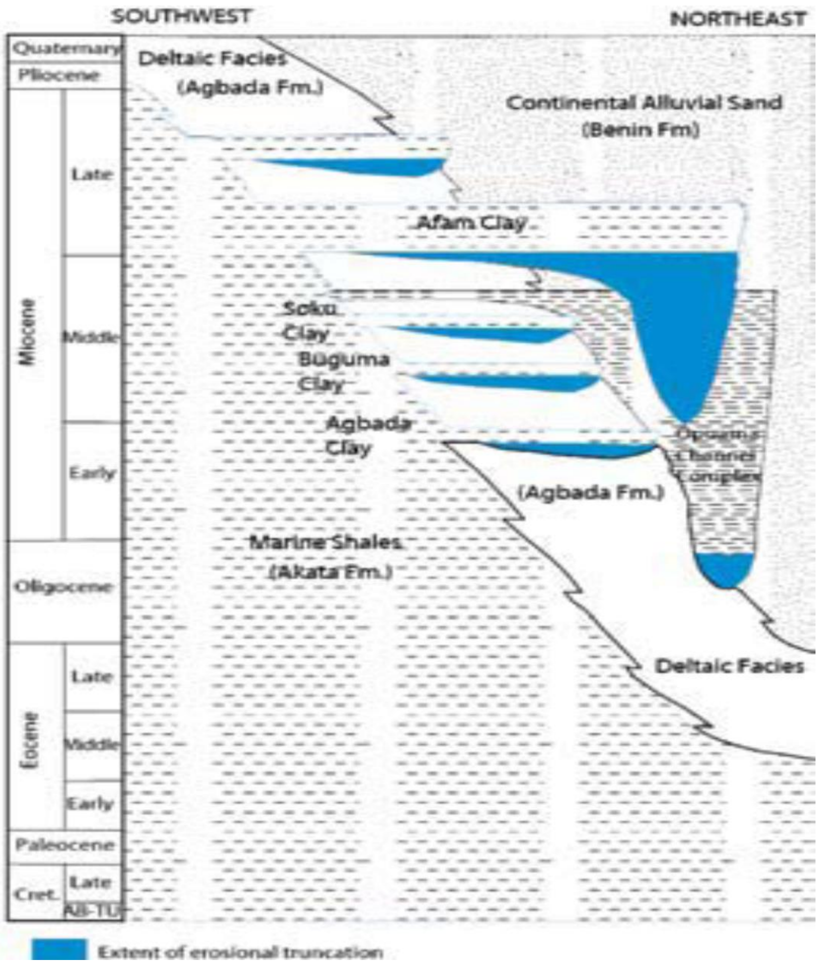

Figure 1b: Stratigraphic column showing the three formation of Niger Delta. (Short and Stauble, 1967).

The production of oil and gas is from accumulation in the pore spaces of reservoir rocks usually sandstone, limestone and dolomite. The formation is characterised by alternating sandstone and shale units varying in thickness from 100ft to 1500ft (Doust and Omatsola, 1990; Short and Stauble, 1967). The sand in this formation is mainly hydrocarbon reservoir with shale providing lateral and vertical seal.

The delta proper began developing in the Eocene, accumulating sediments that now are over 10 kilometers thick. The Niger Delta Province contains only one identified petroleum system, namely the Tertiary Niger Delta (Akata –Agbada) petroleum system (Doust and Omatsola, 1990).

The tectonic framework of the continental margin along the West Coast of equatorial Africa is controlled by Cretaceous fracture zones expressed as trenches and ridges in the deep Atlantic. The fracture zone ridges subdivide the margin into individual basins, and, in Nigeria, form the boundary faults of the Cretaceous Benue-Abakaliki trough, which cuts far into the West African shield. The trough represents a failed arm of a rift triple junction associated with the opening of the South Atlantic. In this region, rifting started in the Late Jurassic and persisted into the Middle Cretaceous. In the region of the Niger Delta, rifting diminished altogether in the Late Cretaceous (Ogboke, 2006).

After rifting ceased, gravity tectonism became the primary deformational process. Shale mobility induced internal deformation and occurred in response to two processes. First, shale diapirs formed from loading of poorly compacted, over-pressured, prodelta and delta-slope clays (Akata Formation.) by the higher density delta-front sands (Agbada Formation.). Second, slope instability occurred due to a lack of lateral, basinward, and support for the under-compacted delta-slope clays (Akata Formation.). For any given depobelt, gravity tectonics were completed before deposition of the Benin Formation and are expressed in complex structures, including shale diapirs, roll-over anticlines, collapsed growth fault crests, back-to-back features, and steeply dipping, closely spaced flank faults (Doust and Omatsola, 1990). These faults mostly offset different

parts of the Agbada Formation and flatten into detachment planes near the top of the Akata Formation.
Petroleum in Niger Delta is produced from sandstone and unconsolidated sands predominantly in the Agbada Formation (Bouvier et al., 1989). Most known traps in Niger Delta fields are structural although stratigraphic traps are not uncommon. The structural traps developed during synsedimentary deformation of the Agbada paralic sequence. A variety of structural trapping elements exists, including those associated with simple rollover structures; clay filled channels, structures with multiple growth faults, structures with antithetic faults, and collapsed crest structures (Ogboke, 2006).
The onshore portion of the Niger Delta province is delineated by the geology of southern Nigeria and southwestern Cameroon. The northern boundary is the Benin flank, an east-northeast trending hinge line south of the West Africa basement massif (Aigbedion and Iyayi 2006). The northeastern boundary is defined by outcrops of the Cretaceous on the Abakaliki High and further east-south-east by the Calabar flank a hinge line bordering the adjacent Precambrian

Description of Key Elements
The primary objective of this research is to transform raw subsurface data into a predictive geological model. This process is governed by three major scientific pillars: Petrophysics, Geophysics, and Structural Geology.

Petrophysical Analysis
Petrophysics serves as the primary tool for establishing the "ground truth" of the reservoir at the borehole level (Tiab & Donaldson, 2015). This element focuses on characterizing the rock's physical properties:
*Lithological Discrimination***:** Identifying the spatial distribution of sandstone reservoirs versus shale seals to determine the stratigraphic framework (Asquith & Krygowski, 2004).
Storage and Flow Potential: Quantifying porosity (the rock's storage capacity) and permeability (the rock's ability to transmit fluids), which together define the reservoir's economic viability (Tiab & Donaldson, 2015).
Fluid Characterization: Utilizing resistivity measurements to differentiate between water-saturated zones and those containing commercial quantities of hydrocarbons (Archie, 1942; Schlumberger, 1989).

The Structural Architecture: Seismic Interpretation
While petrophysics provides detail at the well, seismic interpretation provides the field-wide context by mapping the subsurface architecture (Bacon et al., 2007):
Seismic-Well Calibration: Establishing a precise correlation between the vertical depth of the well and the horizontal time-slices of seismic data to ensure spatial accuracy (Veeken, 2007).
Geometric Mapping: Tracing continuous stratigraphic horizons to define the lateral extent of reservoir units (Brown, 2011).
Structural Trapping: Identifying faults and folds—such as rollover anticlines—that serve as the physical boundaries where hydrocarbons are trapped and accumulated (Bally, 1987; Adetoye, 2009).

The Predictive Layer: Multi-Attribute Analysis
The research elevates standard interpretation through the use of Seismic Attributes, which are mathematical extractions that act as Direct Hydrocarbon Indicators (DHIs) (Chopra & Marfurt, 2007). By analyzing variables like Amplitude, Energy, and Sweetness, the workflow identifies "sweet spots"—localized areas where high-quality rock is likely to be saturated with oil or gas (Taner, 2001). These attributes serve to validate the structural mappings and reduce the uncertainty inherent in subsurface modeling (Chopra & Marfurt, 2007; Ajisafe & Ako, 2013).

MATERIALS AND METHODS
The Materials used for this research is composed of Dataset which was provided by Shell Petroleum and Development Company through the Department for Petroleum Resources Nigeria. Well header information and suites of logs were provided for the seven drilled wells within the study area all in LAS format. Well header data are important aspect of the well data information since they carry information about individual positions (surface X, Y), total depth(TD), elevation depth (KB, DF, RT). The following suites of logs were provided; gamma ray (GR), resistivity (LLD), density (RHOB), neutron (NPHI), sonic (ΔT) and checkshot data.

Seismic data
3-D post-stack seismic data was provided in SEG-Y 8-bit digital format. The seismic data contained 961 inlines (IL) and 444 cross-lines (XL).

Software
Geophysical software used for this research analysis are Schlumberger Petrel 2014 andHampson Russell software (HRS 10.3.2). Petrel is been used for well correlation, seismic structural and stratigraphic interpretation while Hampson Russell is been used for the inversion of the seismic data into acoustic impedance volume and other reservoir properties.

RESULTS AND DISCUSSION
Well log interpretation
Four composite suites of logs comprise of gamma ray, resistivity, neutron and density logs were run in wells DAVE-01, DAVE-02, DAVE-04, DAVE05, and DAVE-06 plotted on a triple combo template. Gamma ray in track one identified lithology within the wells to be

mainly sand (low gamma reading) identified as yellow color and shale (high gamma reading) identified as black color. The lithology identification was further enhanced by the overlay of the neutron and density log on the same track in a compatible scale. Lithologic units of similar motif were identified and correlated across the wells. The stratigraphic trends show a generally lateral continuous lithology across the field. From visual inspection of the log track, zones of interest (porous and permeable) were marked for hydrocarbon accumulation. Fluid within the reservoir were identified using resistivity log. High resistivity values are an indication of hydrocarbon saturation. Five wells penetrated four different lithological sands (A, B, C, and D). Sand zones were marked and correlated across the selected well (Figure 2). The correlation panel shows that the sand bodies (yellow) spread across the wells with varying thickness and as a result of fault some of the sand units occurred at greater depth than their adjacent units. From quick-look analysis of the conventional log three sand zone (A, C, and D) was identified to be hydrocarbon bearing within the study area.

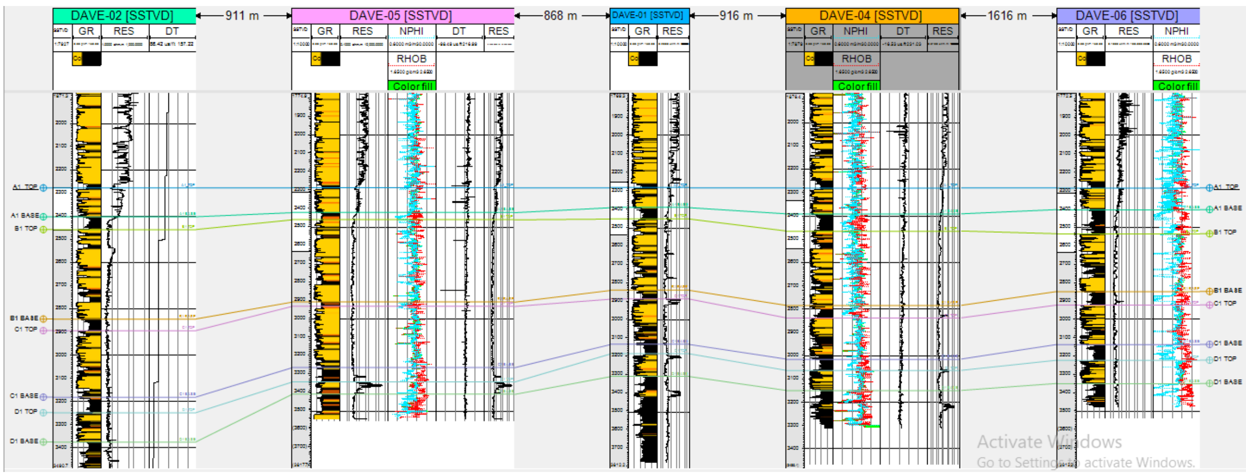

Figure 2: Well correlation panel showing identified sand across the field

This well correlation panel illustrates the identified sand units (A, B, C, D) across five wells. The yellow bands represent sands, with notable lateral continuity disrupted by faults, which result in varying depths of occurrence. Hydrocarbon-bearing sands (A, C, D) are well developed in structurally favourable traps.

Petrophysical analysis

The parameters calculated from well logs include net to gross (N/G), shale volume, total and effective porosity, water saturation. These parameters would help to effectively quantify the reservoirs in terms of the hydrocarbon pore volume and the amount of hydrocarbon in place. Suites of logs from three wells (DAVE-04, DAVE-05, and DAVE-06) were used to evaluate petrophysical parameters because other well (DAVE-01, and DAVE-02) only have gamma and resistivity logs. Table 1 – 4 shows the result for the different petrophysical parameters. The result revealed that shale volume ranges between 0.112 to 0.181 for reservoir A, 0.087 to 0.171 for reservoir B, 0.116 to 0.172 for reservoir C, and 0.167 to 0.329 for reservoir D, total porosity values range from 0.286 to 0.354 for reservoir A, 0.273 to 0.289 for reservoir B, 0.244 to 0.276 for reservoir C, and 0.242 to 0.268 for reservoir D, effective porosity ranges between 0.269 to 0.334 for reservoir A, 0.259 to 0.268 for reservoir B, 0.218 to 0.255 for reservoir C, and 0.192 to 0.24 for reservoir, permeability ranges between 385.876 to 758.145 for reservoir A, 342.667 to 407.138 for reservoir B, 237.881 to 342.605 for reservoir C, and 267.695 to 320.071 for reservoir D, and water saturation ranges from 0.447 to 0.528, 0.914 to 0.964, 0.9 to 0.999, and 0.286 to 0.976 for reservoir A, B, C, and D respectively.

Table 1: Calculated petrophysical parameters for sand A

Well	Zones	Top	Bottom	Gross	Net	Net to Gross	Shale Volume	Porosity	Permeability	Effective Porosity	Water Saturation
	DAVE-04	2287.288	2397.81	110.522	104.251	0.943	0.181	0.304	470.569	0.277	0.528
A	**DAVE-05**	2294.534	2419.959	125.425	115.315	0.919	0.112	0.286	385.676	0.269	0.447
	DAVE-06	2287.587	2398.6	111.013	107.045	0.964	0.128	0.354	758.145	0.334	0.462
Min				**110.522**	**104.251**	**0.919**	**0.112**	**0.286**	**385.676**	**0.269**	**0.447**
Max				**125.425**	**115.315**	**0.964**	**0.181**	**0.354**	**758.145**	**0.334**	**0.528**
Avg				**115.6533**	**108.8703**	**0.942**	**0.140333**	**0.314667**	**538.13**	**0.293333**	**0.479**

Table 1 presents the petrophysical properties of Sand A, which indicate excellent reservoir quality. The net-to-gross ratios range from 0.919 to 0.964, suggesting predominantly clean sands with minimal shale interference. Porosity values are high, with effective porosity ranging between 0.269 and 0.334, reflecting strong storage capacity. Permeability values are exceptionally good, between 385 and 758 millidarcies, supporting high fluid flow potential. Water saturation remains moderate, around 45 to 53 percent, pointing to a significant presence of hydrocarbons. Overall, Sand A emerges as the most promising reservoir target

Table 2: Calculated petrophysical parameters for sand B

Well	Zones	Top	Bottom	Gross	Net	Net to Gross	Shale Volume	Porosity	Permeability	Effective Porosity	Water Saturation
	DAVE-04	2462.207	2799.625	337.419	260.654	0.772	0.171	0.289	407.138	0.263	0.964
B	**DAVE-05**	2474.519	2903.982	429.463	348.946	0.813	0.096	0.273	341.667	0.259	0.914
	DAVE-06	2541.533	2854.268	312.735	236.368	0.756	0.087	0.281	364.894	0.268	0.948
Min				**312.735**	**236.368**	**0.756**	**0.087**	**0.273**	**341.667**	**0.259**	**0.914**
Max				**429.463**	**348.946**	**0.813**	**0.171**	**0.289**	**407.138**	**0.268**	**0.964**
Avg				**359.8723**	**281.9893**	**0.780333**	**0.118**	**0.281**	**371.233**	**0.263333**	**0.942**

Table 2 displays the petrophysical data for Sand B, which reveals moderate to good reservoir characteristics. The net-to-gross values, ranging from 0.756 to 0.813, show some shale presence but still within productive limits. Porosity and effective porosity lie between 0.273 and 0.289, and 0.259 to 0.268 respectively, indicating decent storage potential. However, the water saturation levels are notably high, from 91 to 96 percent, implying that Sand B is largely water-saturated and likely lacks commercial hydrocarbon saturation. This interpretation is consistent with DHI and amplitude attribute observations.

Table 3: Calculated petrophysical parameters for sand C

Well	Zones	Top	Bottom	Gross	Net	Net to Gross	Shale Volume	Porosity	Permeability	Effective Porosity	Water Saturation
	DAVE-04	3061.698	3145.344	83.646	76.659	0.916	0.172	0.244	237.881	0.218	0.9
C	**DAVE-05**	2943.403	3251.708	308.305	266.852	0.866	0.116	0.265	309.825	0.247	0.957
	DAVE-06	2919.874	3137.122	217.248	180.94	0.833	0.135	0.276	342.605	0.255	0.999
Min				**83.646**	**76.659**	**0.833**	**0.116**	**0.244**	**237.881**	**0.218**	**0.9**
Max				**308.305**	**266.852**	**0.916**	**0.172**	**0.276**	**342.605**	**0.255**	**0.999**
Avg				**203.0663**	**174.817**	**0.871667**	**0.141**	**0.261667**	**296.7703**	**0.24**	**0.952**

Table 3 summarises the reservoir attributes of Sand C, where porosity values range from 0.244 to 0.276 and effective porosity from 0.218 to 0.255. These figures point to fair reservoir potential. Permeability varies from 237 to 342 millidarcies, which supports reasonable fluid movement. However, water saturation values are high in some sections, approaching 99.9 percent, indicating that while there may be hydrocarbons, parts of the sand body could be brine-filled. Sand C therefore holds selective potential, particularly in structurally advantageous zones where DHIs coincide.

Table 4: Calculated petrophysical parameters for sand D

Well	Zones	Top	Bottom	Gross	Net	Net to Gross	Shale Volume	Porosity	Permeability	Effective Porosity	Water Saturation
	DAVE-04	2826.984	3016.654	189.67	160.268	0.845	0.183	0.268	320.071	0.24	0.97
D	**DAVE-05**	3345.688	3401.873	56.185	44.195	0.787	0.329	0.242	267.695	0.192	0.286
	DAVE-06	3226.199	3352.103	125.904	111.675	0.887	0.167	0.257	275.819	0.232	0.976
Min				**56.185**	**44.195**	**0.787**	**0.167**	**0.242**	**267.695**	**0.192**	**0.286**
Max				**189.67**	**160.268**	**0.887**	**0.329**	**0.268**	**320.071**	**0.24**	**0.976**
Avg				**123.9197**	**105.3793**	**0.839667**	**0.226333**	**0.255667**	**287.8617**	**0.221333**	**0.744**

Table 4 outlines the petrophysical evaluation of Sand D. The porosity and effective porosity values range between 0.207 to 0.271 and 0.192 to 0.240 respectively, signifying moderate storage capacity. Permeability is also moderate, between 267 and 320 millidarcies, suggesting acceptable reservoir flow potential. Water saturation varies widely, from 28 to 97 percent, indicating heterogeneity within the sand body. These values suggest that Sand D may have hydrocarbon presence in structurally elevated zones, though certain portions may be water-wet.

Graphical plot of the average petrophysical parameter from DAVE-04, DAVE-05, and DAVE-06 are shown in Figure 3 to 4. This plot reveals the varying ranges of each petrophysical parameters from these wells in the study area. Comparative analysis of the calculated petrophysical output with Rider's classification scheme revealed that the zone of interested can be classed to be a very good reservoir since porosity > 20 and permeability >250.

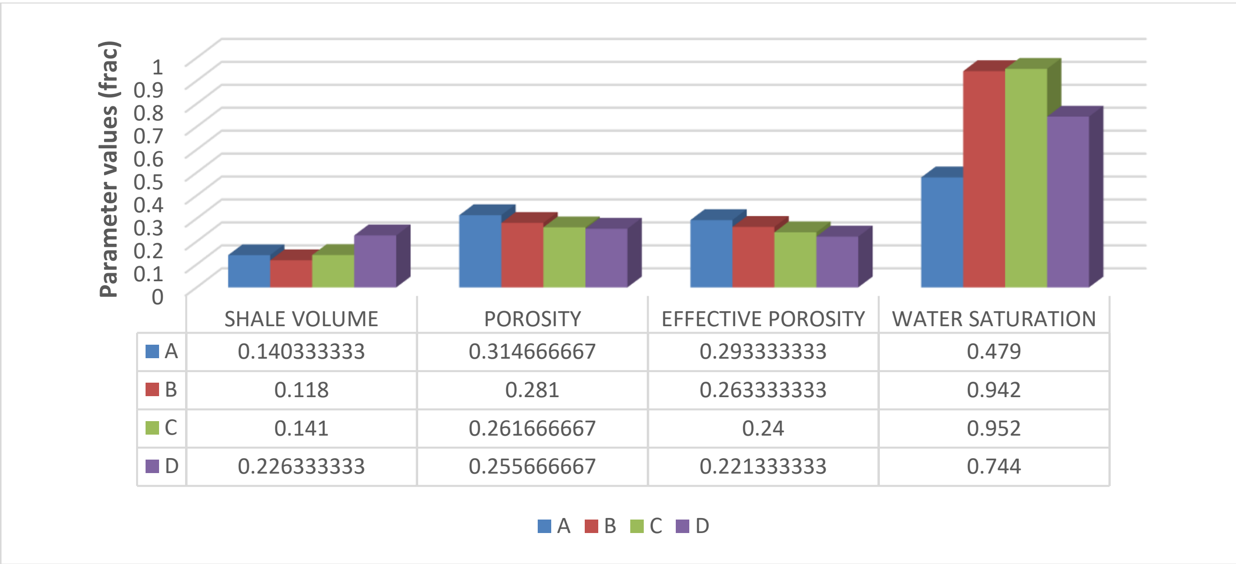

Figure 3: Graphical plot of average petrophysical properties in sand A, B, C, and D

This bar chart displays average petrophysical parameters across the four sand zones. Sand A and C exhibit superior porosity and effective porosity, indicating better reservoir quality. Shale volume remains within acceptable limits for productive sands.

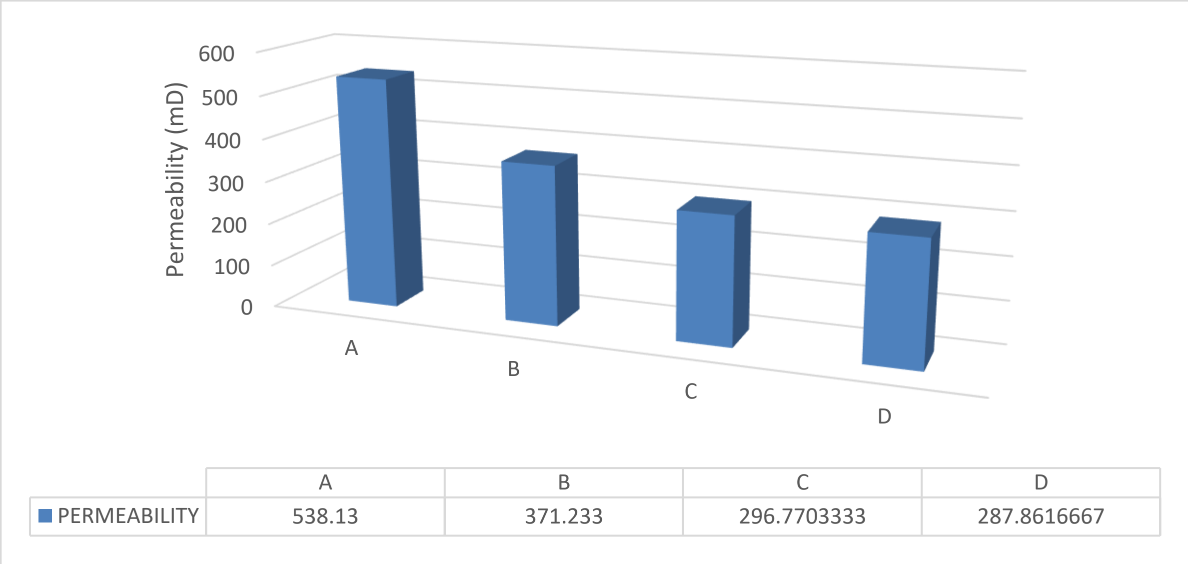

Figure 4: Graphical plot of average permeability in sand A, B, C, and D

This figure shows the average permeability of sands A to D. Sand A has the highest permeability, followed by sands D and C, suggesting favourable flow characteristics essential for hydrocarbon recovery.

Seismic interpretation

Interpretation is a technique or tool by which an attempt is made to transform the whole seismic information into structural or stratigraphical model off the earth. Since the seismic section is the representative of the geological model of the earth, by interpretation, one tries to locate the zone of final anomaly. The main approach for the interpretation of seismic section for this research is on structural analysis. In structural analysis main emphasis is on structural traps in which tectonic play an important role. Tectonic setting usually governs which types of the structure are present and how the structural features are correlated with each other, so tectonic of the area is helpful in determining the structural style of the area and to locate traps.

Fault interpretation

Mapping and interpretation of faults from the seismic section were made possible base of the usage of variance edge, structural smoothing and trace amplitude gain correction attributes were applied to the 3D seismic data where lateral extent of the faults was mapped on the seismic time slice to determine the full extent of the fault in the field. Fault stick interpretation was done on every 10th inline number on the interpretation window using this clue, faults are recognized most often on seismic section by the terminations of the strata reflectors of the fault. Fault picking were typically performed by looking at both coherency time slice and vertical transects through amplitude volume simultaneously. A seismic amplitude transects and coherency time slice (Figure 5, 6 and 7) section clearly displayed structural traps and faults.

With the structural style of the area in mind to provide a broad context for understanding the pattern of faulting that may be expected. Faults were identified, assigned unique colour and displayed on inline section and time slice on their respective fault picked across the section. The major faults identified in the area were rollover anticline, synthetic and antithetic faults.

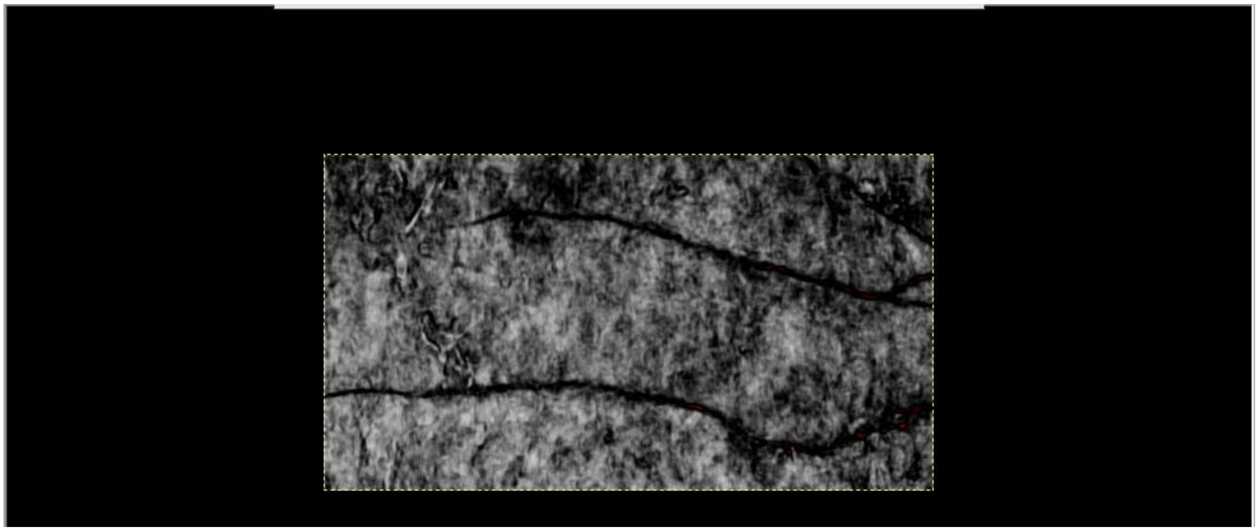

Figure 5: Time slice highlighting structural traps of the field

The time slice image highlights structural features in the field. Bright coherency contrasts reveal fault boundaries and possible trap zones, crucial for structural interpretation.

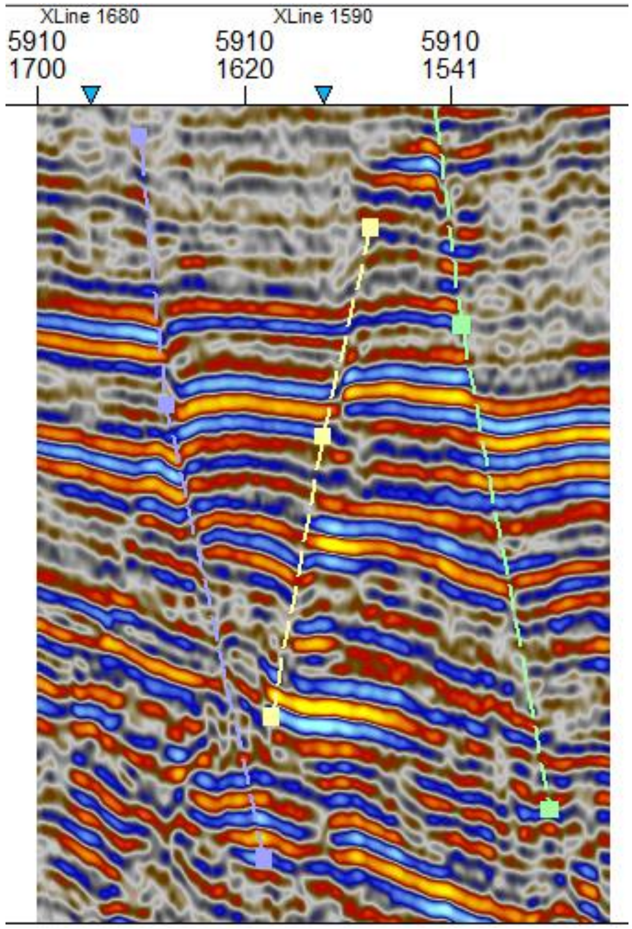

Figure 6: Picked fault stick on seismic inline

This figure shows the picked fault sticks on an inline section. These picked faults represent major displacement features contributing to reservoir compartmentalization.

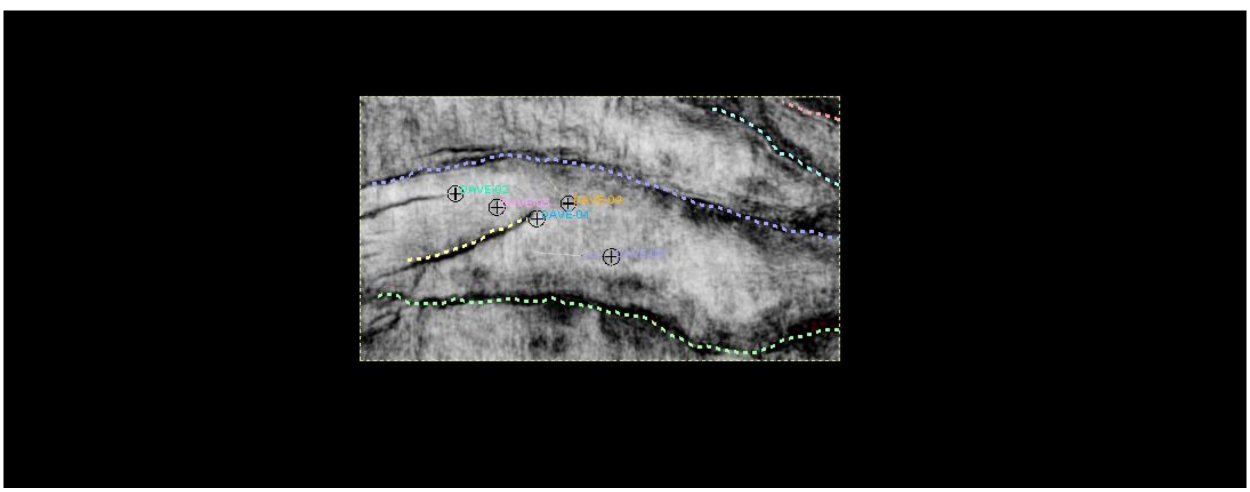
Figure 7: Time slice highlighting interpreted structural traps of the field

The seismic time slice further emphasises the interpreted faults' spatial extent, correlating with major structural traps that may host hydrocarbons.

Seismic well tie calibration

The greater accuracy of the maps generated from seismic interpretation is dependent on the control the geoscientist has when mapping the subsurface. This control can be increased by the correlation of seismic data and borehole data. Figure 8 shows the result of the synthetic seismogram generated for this research there by enabling us tie borehole formation tops identified in wells with specific reflectors on the real seismic section and to quantitatively evaluate seismic attributes, such as amplitude, frequency, amplitude versus offset. Checkshot data, sonic and density are the desired input parameters contain in well needed to create a synthetic trace. From the processed seismic data, a source wavelet known as Ricker wavelet was extracted and used for convolution process. A bulk shift of 3ms was applied so that maximum between trace event from the well and seismic were aligned on the synthetic seismogram.

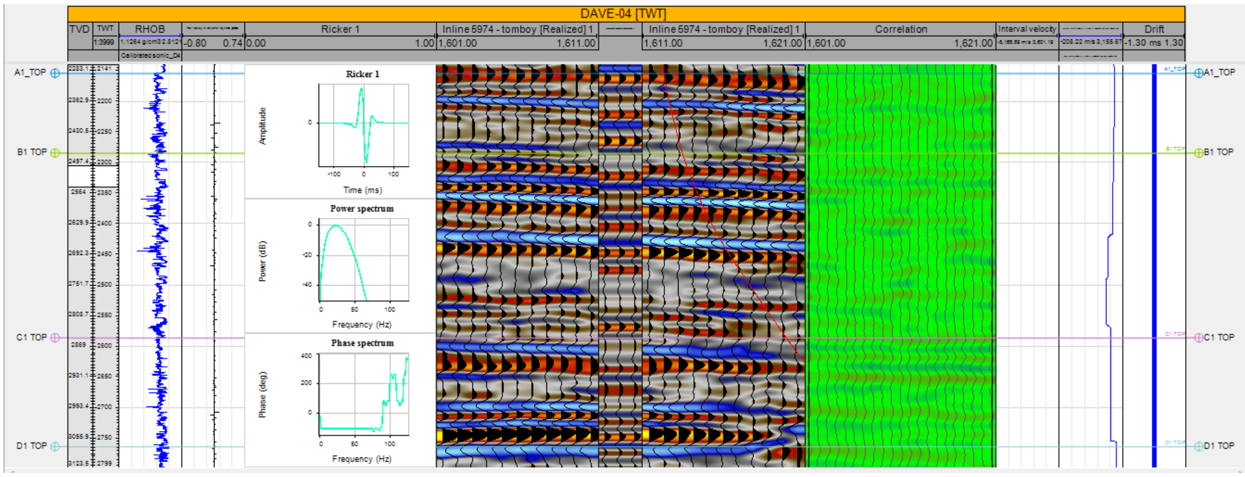

Figure 8: Synthetic seismogram

This synthetic seismogram aligns well tops from borehole data with seismic reflectors, ensuring accurate correlation between geologic and geophysical interpretations.

Horizon mapping/Time surface generation

Having correlated the well top and generating synthetic seismogram, the tops were displayed on the seismic section with their corresponding seismic trace (peak) for each sand top are mapped on a seismic trace by tracking laterally consistent reflectors on both inline and crossline reflectors. From the well tie, sand top identified from the well were aligned to red trace (peak event) from which the 3D structure of the reservoir was mapped. Figure 9 show the picked horizon across the seismic section at interval of 10x10 inline and crossline spacing to build up denser seed grind and honoring the fault stick displaced across the seismic section.

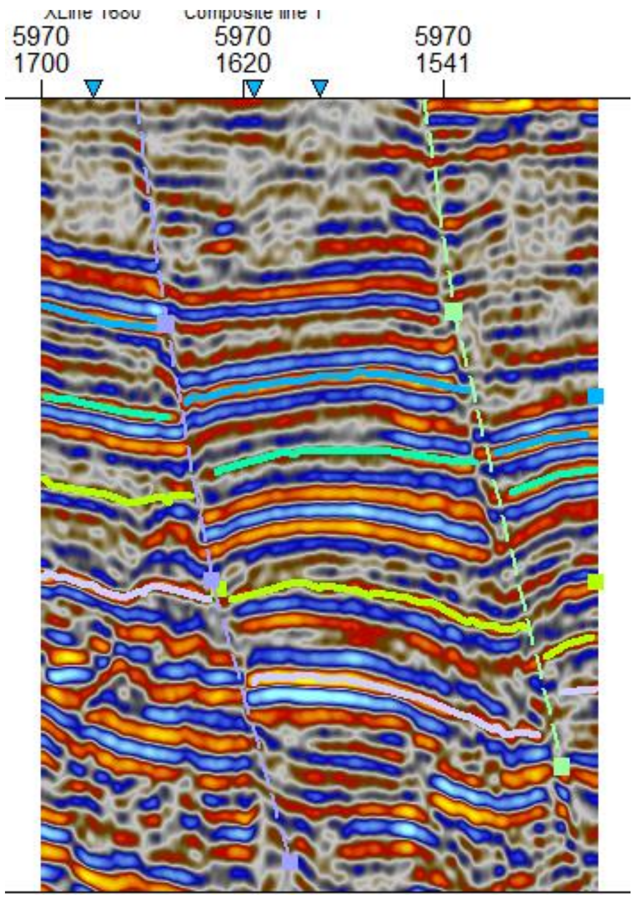

Figure 9: Four horizons identified for each sand zone across the seismic

This horizon pick illustrates the tracking of continuous reflectors across seismic lines. These reflectors represent the tops of the identified reservoir sands (A to D).
Horizon mapping were carried out from the top of the seismic section, where definition of trace is usually best and work downwards the section into area where the signal-to-noise ratio is reduced and the reflector definition is less clear.

Direct hydrocarbon indicators (Attribute extraction)
Seismic attributes analysis carried out on extracted amplitude map for each of the reservoir sand A, B, C, and D top indicate that strong amplitude anomalies exist for each reservoir (A, C, and D) at different part of the field. The part of the field where these strong amplitude anomalies were observed corresponds to anticlinal (A and D) and fault assisted structure (C). Results indicates that strong amplitude anomalies are structurally controlled as they are seen occurring on structural top maps. The high amplitude contrast on top of this anticlinal structure implies it is overlaid by shale which serves as seal or cap rock. High amplitude and strong reflection strength along the margin of the faults are indication of smearing of the fault and sealing of the reservoirs by clays or shales, thus trapping the hydrocarbon migration within the closures. Figure 10, and 13, revealed amplitude anomalies as seen on structural high and drilled wells are in this zone which suggests prospect conformity with regional structural high while Figure 12 amplitude anomalies were observed to be away from regional structural high but rather around fault-controlled structures and away from drilled well identified as a lead and subject to further studies and confirmation. Figure 11 revealed no amplitude anomalies that confirm to structure highlighting the output from log analysis that this zone is completely saturated with brine.

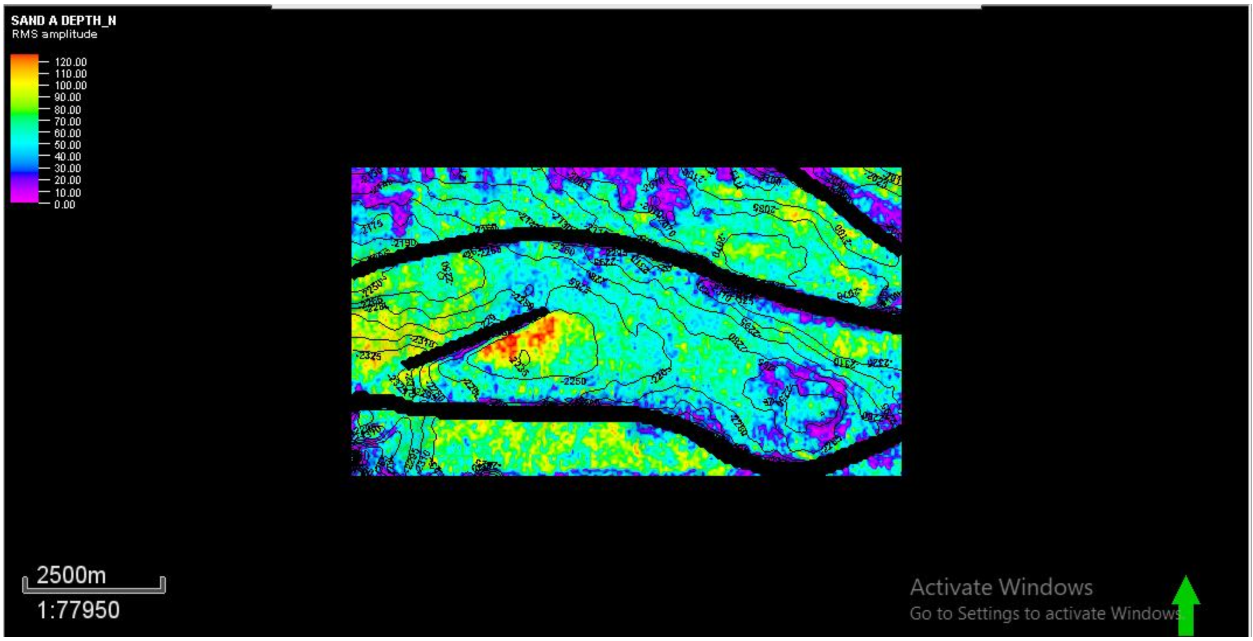

Figure 10: RMS Amplitude attribute for Sand A

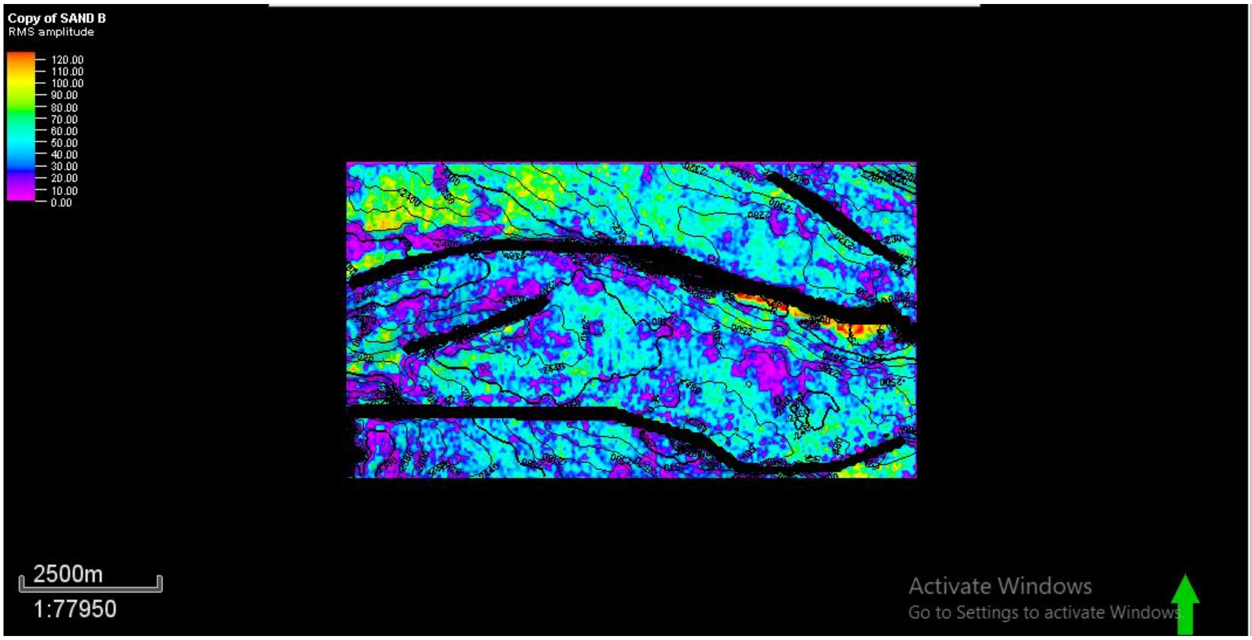

Figure 11: RMS Amplitude attribute for Sand B

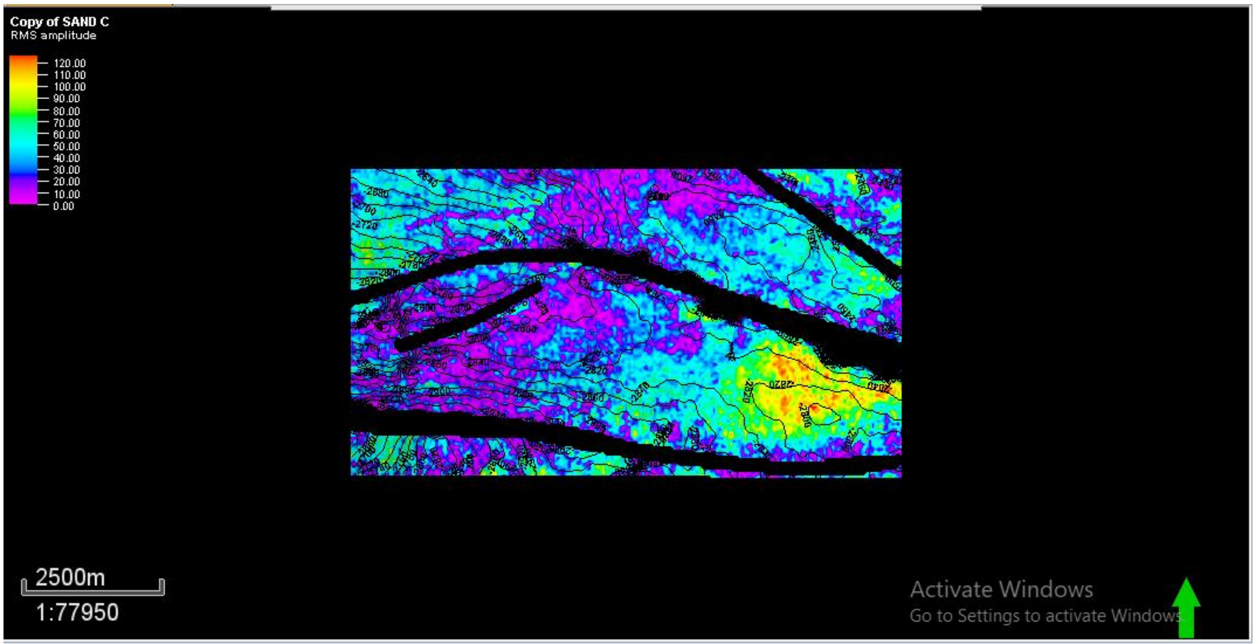

Figure 12: RMS amplitude for Sand C

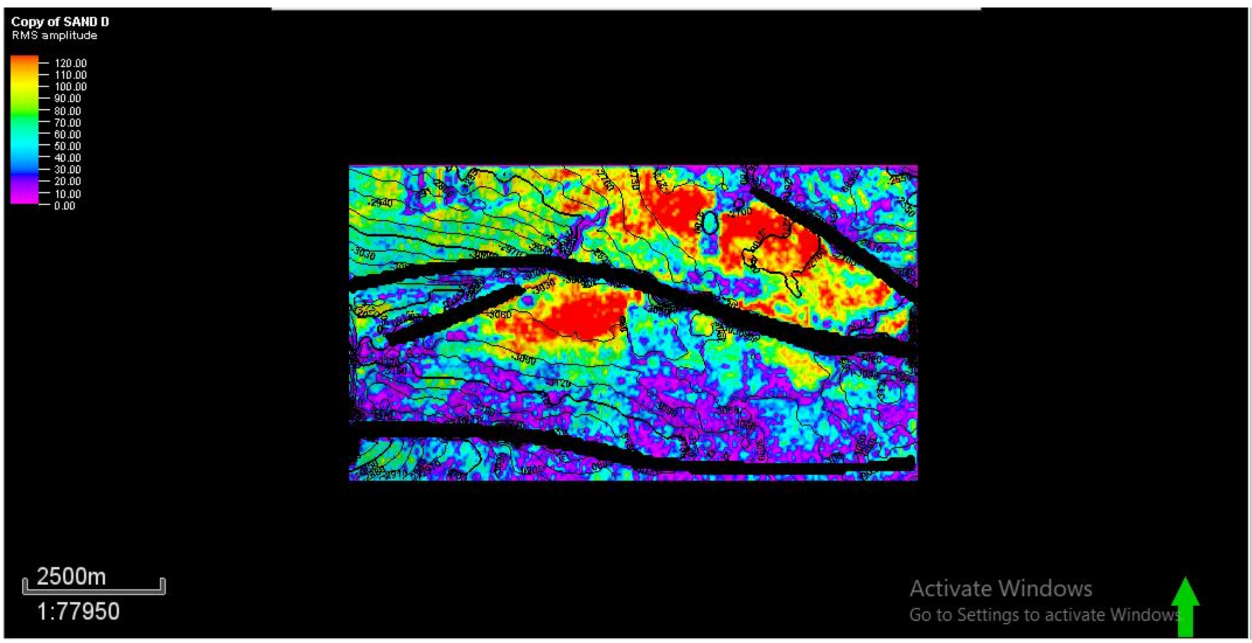

Figure 13: RMS Amplitude for Sand D

Figures 10 to 13 present RMS (Root Mean Square) amplitude attribute maps for Sands A–D, highlighting distinct seismic responses that serve as direct hydrocarbon indicators (DHIs) and aid hydrocarbon evaluation. Sand A (Figure 10) and Sand D (Figure 13) both display strong amplitude anomalies conforming to structural highs, confirming their prospectivity as hydrocarbon-bearing zones controlled by anticlinal traps. Sand B (Figure 11), however, exhibits uniform low-amplitude responses, consistent with well-log interpretations of water saturation and thus showing limited hydrocarbon potential. In contrast, Sand C (Figure 12) reveals localized high-amplitude build-ups adjacent to fault systems, pointing to potential fault-assisted hydrocarbon entrapment. Collectively, these maps demonstrate varied trapping mechanisms across the field—structural highs in Sands A and D, fault-related entrapment in Sand C, and non-hydrocarbon saturation in Sand B.

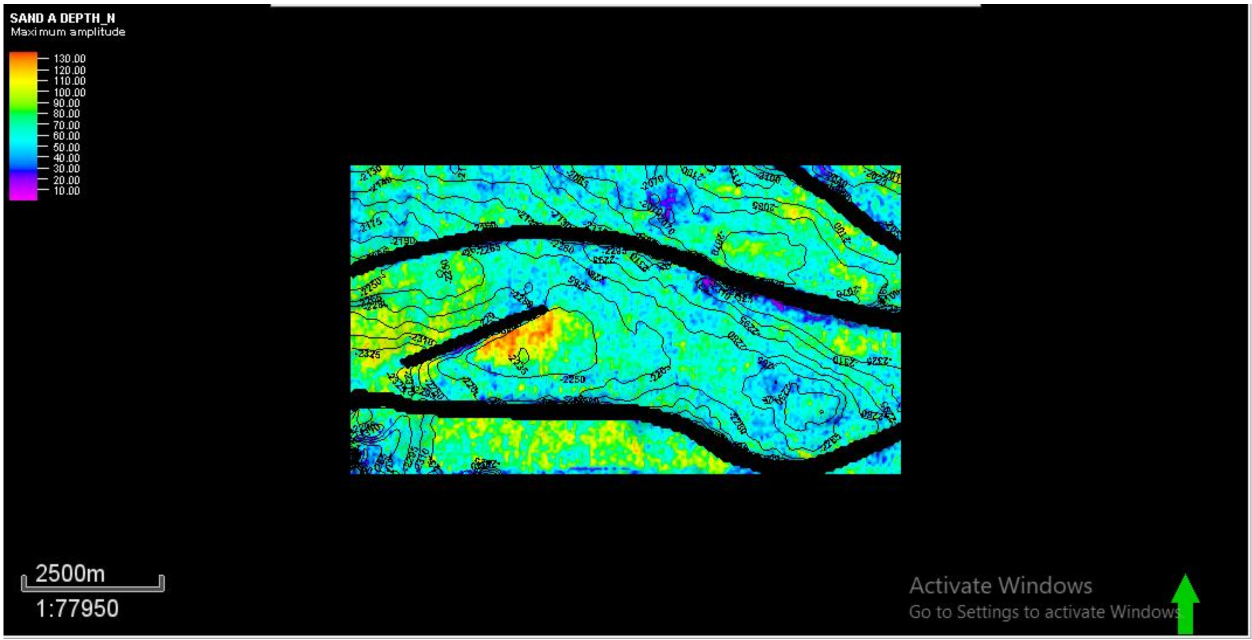

Figure 14: Maximum Amplitude attribute for Sand A

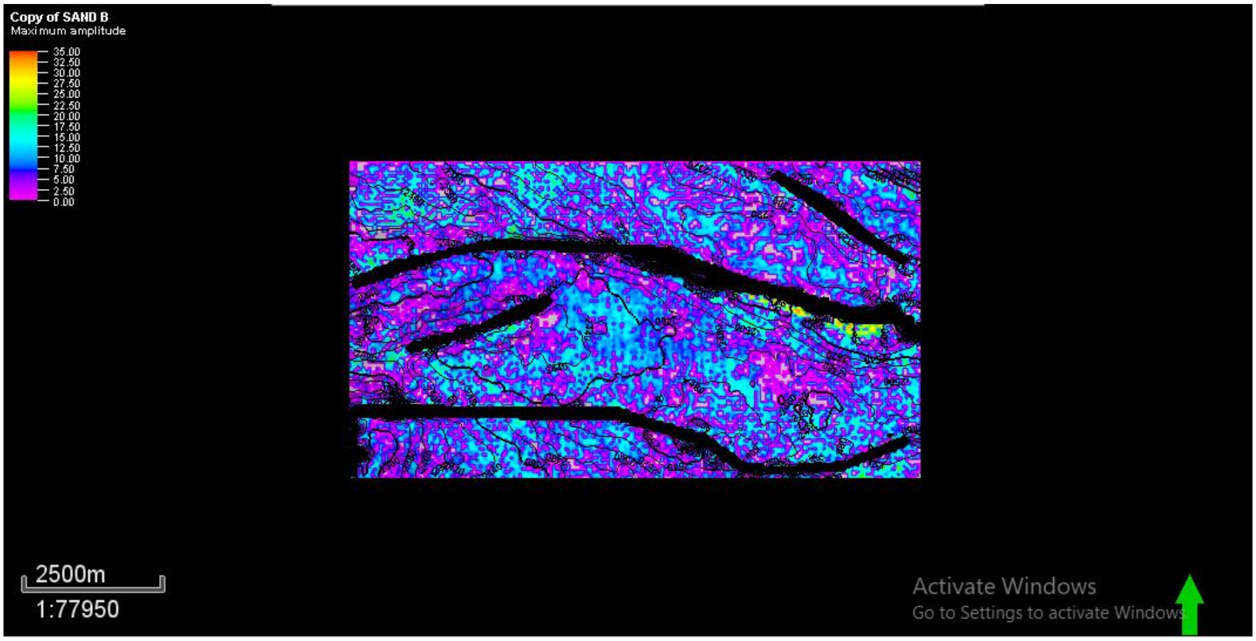

Figure 15: Maximum Amplitude attribute for Sand B

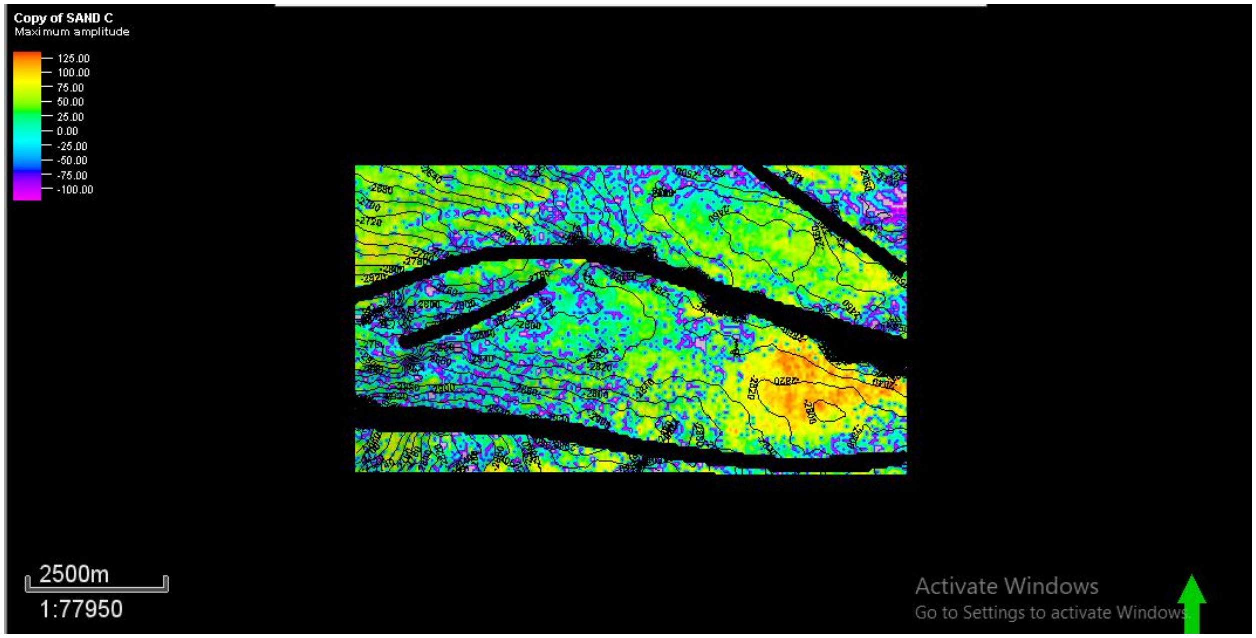

Figure 16: Maximum Amplitude for Sand C

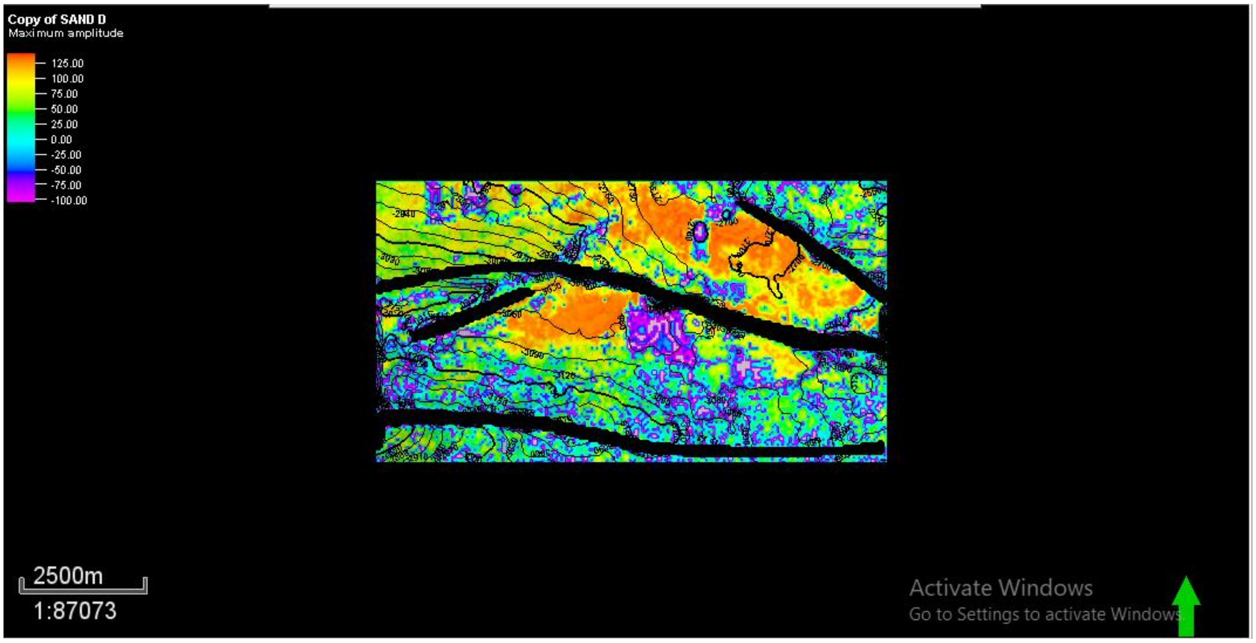

Figure 17: Maximum Amplitude attribute for Sand D

The Maximum Amplitude (also known as Envelope Attribute) maps for Sands A–D reinforce and complement the RMS amplitude observations. Sand A (Figure 14) and Sand D (Figure 17) exhibit distinct high-amplitude anomalies conforming to structural highs, strengthening the evidence for hydrocarbon-filled anticlinal traps. Sand B (Figure 15) maintains a weak, uniform amplitude response, consistent with water saturation as earlier confirmed by well logs and RMS analysis. Sand C (Figure 16) reveals localized bright amplitude patches along fault zones, emphasizing the role of fault-assisted entrapment. Collectively, these maximum amplitude maps highlight structural and stratigraphic trapping mechanisms across the sands and sharpen the hydrocarbon prospectivity interpretation already suggested by the RMS amplitude attributes.

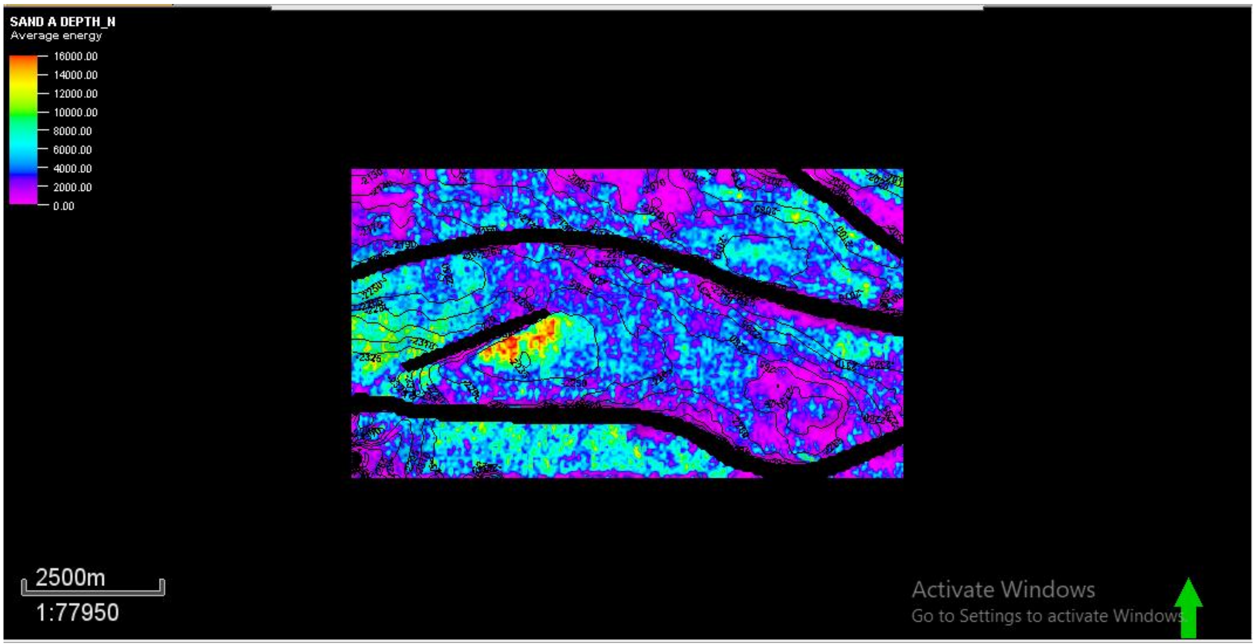

Figure 18: Average energy attribute for Sand A

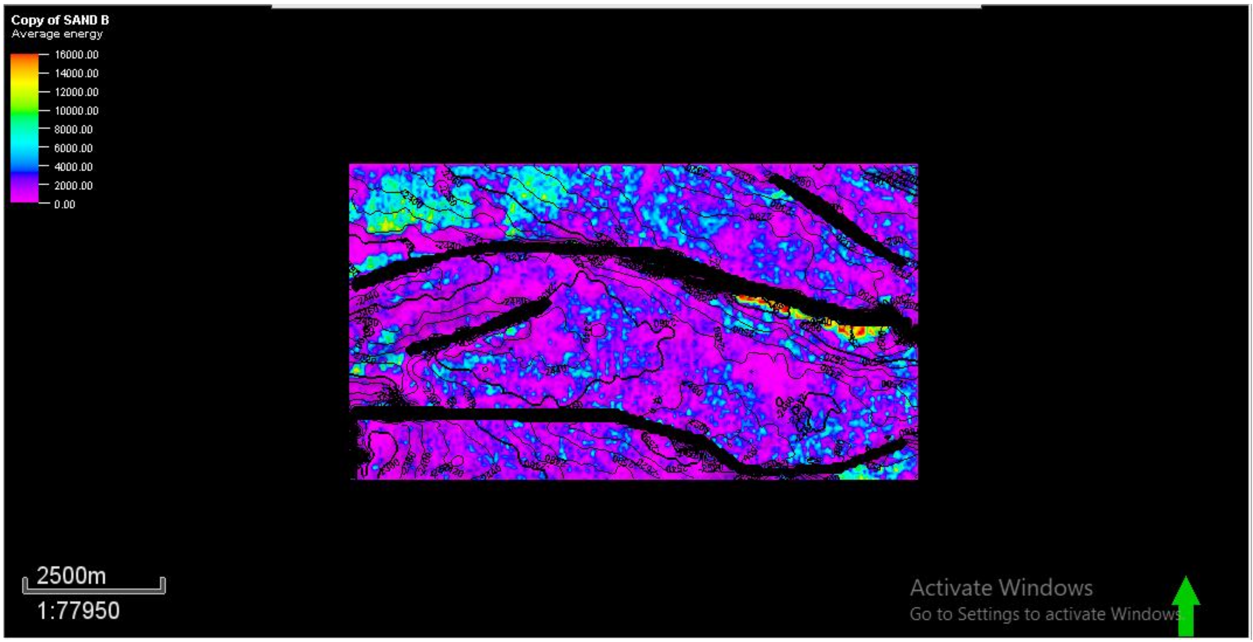

Figure 19: Average energy attribute for Sand B

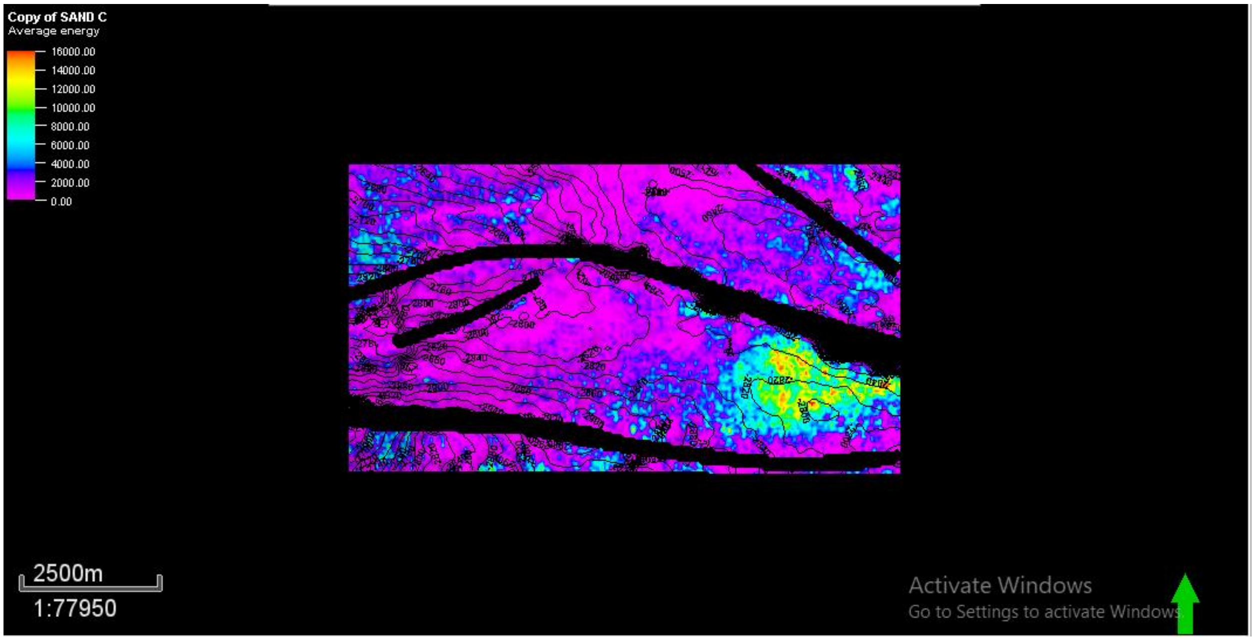

Figure 20: Average energy amplitude for Sand C

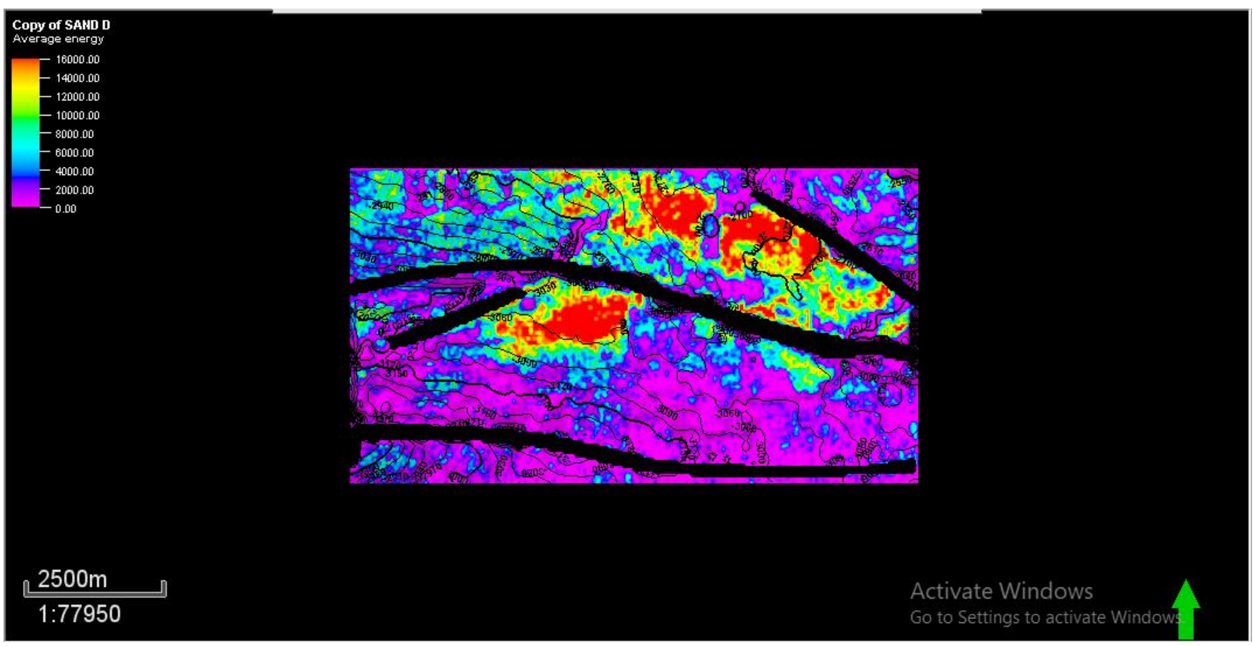

Figure 21: Average energy attribute for Sand D

The average energy attribute maps provide further insight into hydrocarbon potential across Sands A–D. Sand A (Figure 18) shows a concentrated high-energy anomaly at the structural crest, reinforcing evidence of hydrocarbon charge in anticlinal traps. Sand B (Figure 19) exhibits uniformly low energy values, consistent with water saturation and the absence of hydrocarbons. Sand C (Figure 20) reveals localized high-energy build-ups along fault-assisted traps, highlighting the role of structural complexity in hydrocarbon entrapment. Sand D (Figure 21) presents a strong high-energy zone conforming to the structural high, suggesting a laterally extensive hydrocarbon-bearing reservoir. Collectively, these maps strengthen earlier RMS amplitude observations and confirm the value of average energy (or maximum amplitude/envelope attributes) as diagnostic indicators of reservoir prospectivity.

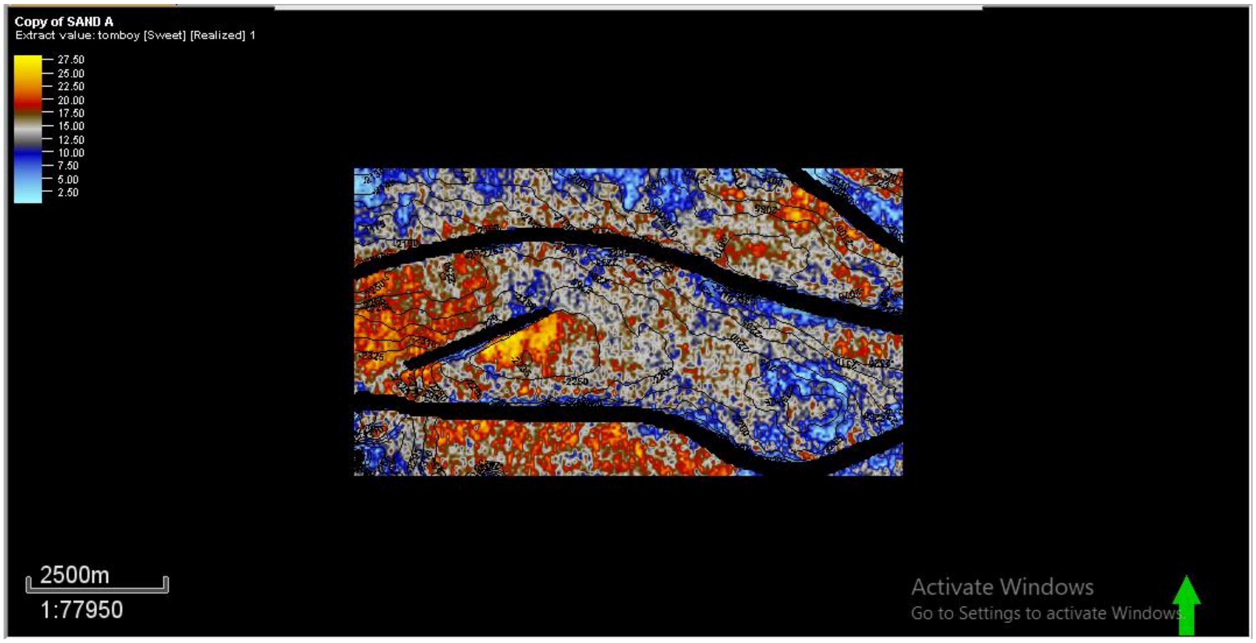

Figure 22: Sweetness attribute for Sand A

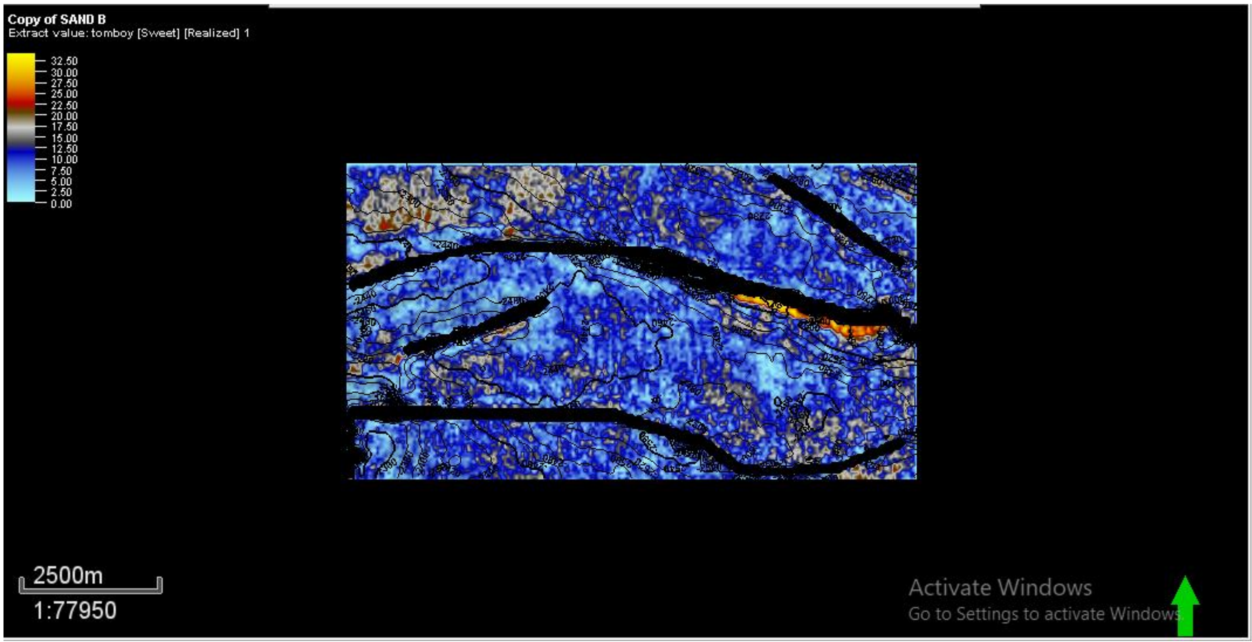

Figure 23: Sweetness attribute for Sand B

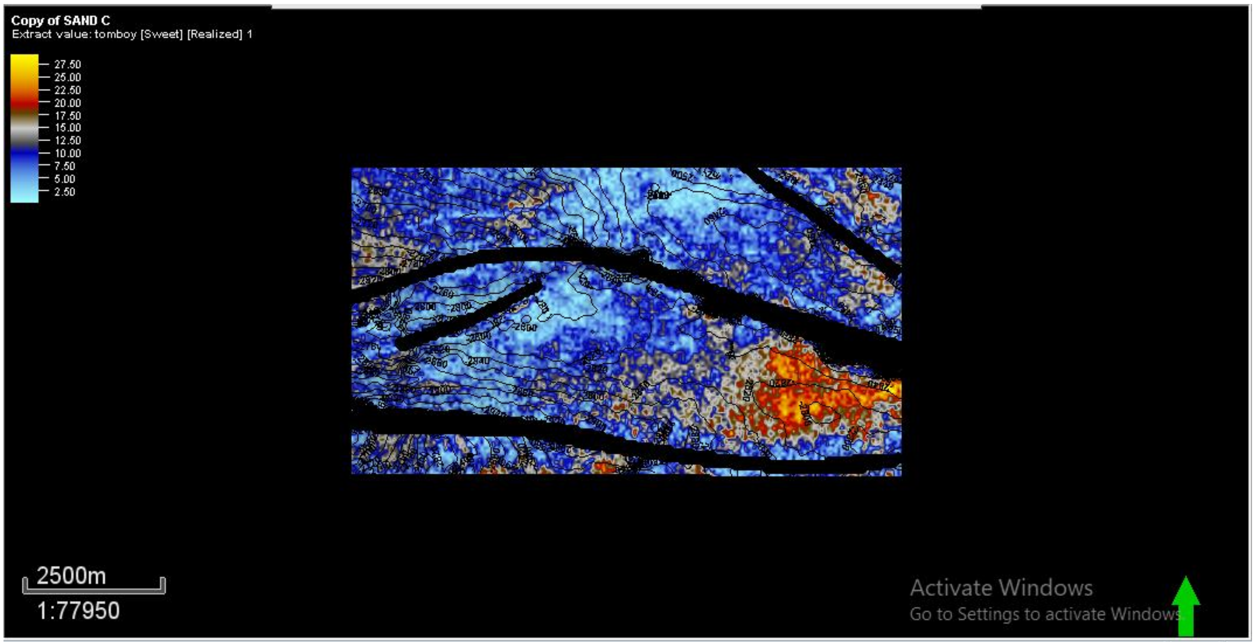

Figure 24: Sweetness attribute for Sand C

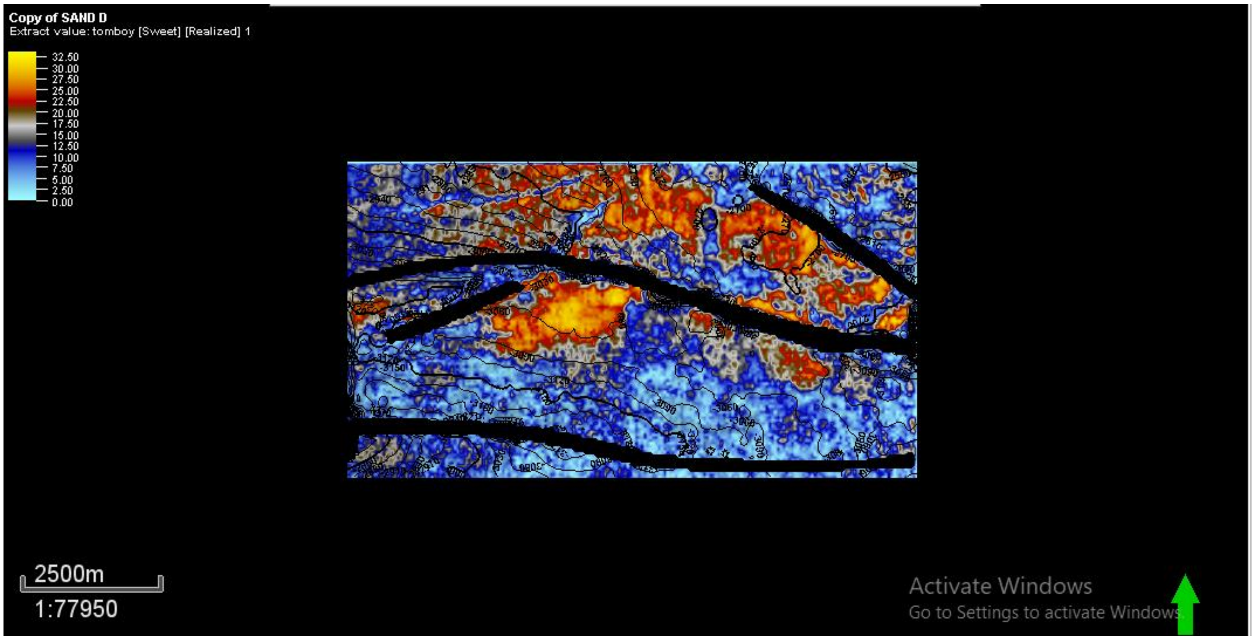

Figure 25: Sweetness Attribute for Sand D

The sweetness attribute analysis for the Dave Field provides a comprehensive view of reservoir quality and fluid content across different sands. The sweetness map for Sand A (Figure 22) displays a clear region of high sweetness values at the structural crest, indicating not only fluid fill but also a high-quality reservoir with good porosity. In contrast, the sweetness map for Sand B (Figure 23) consistently shows low values, which aligns with the interpretation that this sand is water-bearing and of low quality. For Sand C (Figure 24), the map reveals localized areas of high sweetness near fault-assisted traps, suggesting that the hydrocarbon leads in this sand are situated in zones with good reservoir properties. Similarly, the sweetness map for Sand D (Figure 25) shows high values that conform to the structural high, confirming that this sand has both the necessary rock properties and fluid content for a commercially viable hydrocarbon reservoir. This combined analysis demonstrates how the sweetness attribute effectively highlights both hydrocarbon presence and favorable reservoir quality.

Discussion

The well correlation panel (Figure 1) illustrates the distribution of four main sand bodies (A–D) across the field. The sands demonstrate lateral continuity disrupted by faulting, which has compartmentalized the reservoirs into structural traps. Hydrocarbon-bearing sands (A, C, and D) exhibit favorable thickness variations and structural settings, consistent with reservoir-scale heterogeneities reported in similar Niger Delta studies (Avbovbo, 1978; Doust and Omatsola, 1990). Sand B, though laterally extensive, shows evidence of high water saturation, suggesting limited hydrocarbon potential.

Petrophysical evaluation (Tables 1–4) indicates that Sand A is the most prospective reservoir, with high net-to-gross values (0.919–0.964), excellent porosity (0.286–0.354), and very good permeability (385–758 mD). These values align with Rider's (2002) classification of high-quality reservoirs and are comparable to findings in analogous deltaic settings (Adeogba et al., 2005). Sand C also shows fair reservoir potential, with porosity values between 0.244 and 0.276 and permeability up to 343 mD, though its high water saturation (up to 99.9%) limits commercial hydrocarbon accumulation in some intervals. Sand D exhibits moderate petrophysical quality with heterogeneous water saturation (28–97%), suggesting that structural highs and closures are critical for its prospectivity. In contrast, Sand B is predominantly water-saturated (91–96%), indicating poor hydrocarbon potential.

Overall, the integration of well log and seismic data suggests that Sand A is the primary exploration target, while Sands C and D hold secondary potential depending on structural positioning. Sand B, though laterally continuous, is unlikely to yield significant hydrocarbons due to its poor fluid properties and brine saturation. This integrated interpretation underscores the importance of combining petrophysical evaluation with seismic attribute, seismic inversion, AVO and structural analysis to accurately delineate reservoir quality and hydrocarbon potential (Schlumberger, 1989; Aniefiok and Chuks, 2018).

The seismic attributes analysis which included RMS Amplitude, Maximum Amplitude, Average Energy, and Sweetness, provides a robust and comprehensive picture of the JASMI Field's subsurface. Each of these attributes acts as a direct hydrocarbon indicator (DHI), and their combined use significantly reduces the risk and uncertainty associated with exploration. This aligns with previous studies in the Niger Delta, which have demonstrated the effectiveness of integrating seismic attributes with well logs and structural analysis for accurate reservoir delineation (Adetoye, 2009; Ajisafe & Ako, 2013; Aizebeokha & Olayinka, 2011).

The analysis confirms that the strong amplitude anomalies observed are structurally controlled, occurring at either anticlinal highs (Sands A and D) or fault-assisted traps (Sand C). The high amplitude and strong reflection strength along the fault margins are a key indication of effective sealing, which traps hydrocarbons within these closures. The distinct contrast between the high-amplitude anomalies and the surrounding low-amplitude background, as seen in the RMS and Maximum Amplitude maps (Figures 10–13 and 14–17), is a powerful indicator of gas or oil accumulation. This is consistent with findings from other Niger Delta studies that show highly prospective areas are characterized by bright spots and amplitude anomalies (Nwaezeapu & Olowokere, 2019; Oyedele et al., 2020).

Furthermore, the Sweetness attribute provides a critical sanity check by confirming that the high-amplitude zones also correspond to thick, porous sands. This is crucial for distinguishing between fluid effects and lithological effects, ensuring that the identified anomalies are truly related to hydrocarbons and not simply to changes in rock type (Aizebeokha & Olayinka, 2011; Oluwatoyin & Olowokere, 2021). The consistent low-amplitude and low-sweetness response observed in Sand B across all attributes (Figures 11, 15, 18, and 23) validates the well-log analysis that indicated this sand is water-saturated, providing a strong negative control for the analysis.

CONCLUSION

This study successfully integrated petrophysical analysis and seismic attribute interpretation to evaluate hydrocarbon potential in the GOTO Field, Niger Delta, with four reservoir sands (A–D) delineated from well log correlation (Figure 2), and petrophysical results (Tables 4.1–4.4) identifying Sand A as the most prospective reservoir, characterized by high porosity, excellent permeability, and moderate water saturation, while Sands C and D exhibit moderate reservoir quality with localized hydrocarbon potential, and Sand B is largely water-saturated and therefore non-prospective. Seismic attribute analysis (Figures 4.27–4.42) reveals strong amplitude anomalies and high-energy responses in Sands A, C, and D, confirming their hydrocarbon-bearing nature, and these anomalies, supported by sweetness attribute responses, demonstrate that reservoir quality and fluid presence are effectively captured through attribute analysis. The consistency between petrophysical results and seismic attributes highlights the effectiveness of integrating these methods in reservoir characterization, as this approach reduces exploration uncertainty, improves hydrocarbon prediction, and enhances confidence in identifying viable drilling targets. Overall, the study confirms that the combined use of well log petrophysics and seismic attributes is a robust and reliable tool for hydrocarbon exploration and reservoir evaluation in complex deltaic environments such as the Niger Delta.

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