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Full Length Research

Integration of spectral decomposition using fast Fourier transform, seismic facies and attributes analysis in delineating complex structural and stratigraphic features

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ABSTRACT: Spectral decomposition using the Fast Fourier Transform was integrated with seismic facies and attribute analysis to delineate complex structural and stratigraphic features in the B field of the Niger Delta basin, Nigeria. The complex structural style and stratigraphic architecture of the Niger Delta basin, combined with the need to increase the discovery of hydrocarbon accumulations, demand the application of more nuanced seismic interpretation techniques in exploration. Conventional techniques are more suited for the discovery of structural traps. The methodology used in the work focuses on both structural and stratigraphic trapping elements. The objective of the study was to delineate complex structural and stratigraphic features within the B-field that can serve as viable hydrocarbon exploration targets. The methodology includes well facies analysis and correlation, reservoir identification and well-to-seismic tie, structural interpretation, seismic facies and attribute analysis, and spectral decomposition using the fast Fourier transform. The B field lies within an extensional regime, and the trapping is a simple faulted rollover anticline. Three stratigraphic intervals were identified from well analysis, corresponding to the freshwater sands of the Benin Formation, the paralic sequence of the Agbada Formation and the marine shales of the Akata Formation. Additionally, four reservoir intervals were identified and correlated. The structural style is dominated by a structure controlling basin-dipping boundary growth fault trending approximately east-west. There are other smaller faults that are synthetically linked to the boundary fault and also antithetic faults. Seismic facies analysis identified three dominant facies types, with the reservoir interval having more type II facies. Attribute analysis helped to characterise the reservoir intervals and highlighted the important heterogeneity of facies and fluid distribution within the reservoirs. Spectral decomposition revealed important channel features, with the channel system identified as braided.

Keywords: Channel systems, deltaic environments, fast Fourier transform, Niger Delta, seismic facies analysis, spectral decomposition, reservoir characterisation.

INTRODUCTION

The Cenozoic stratigraphic systems of the Tertiary Niger Delta Basin are geologically among the most difficult strata to decipher, both in terms of stratigraphic and structural interpretation. However, high global demand for oil and gas has led to an increase in exploration and development efforts in already explored areas around the world, such as the deep deposits of the Niger Delta.

With hydrocarbon reserves depleted and no major discoveries being made, the responsibility falls on petroleum exploration and production companies to maximise the potential of the field in which they operate. This may include searching for hydrocarbons located in yet-to-be-discovered deposits or bypassed sands, or thin beds and other stratigraphic traps. Due to the limitations of traditional seismic interpretations, these situations could not be easily managed, and drilling costs increased. If companies in the oil and gas business want to make a profit, something has to be done.

One of the challenges facing the Nigerian economy is its direct dependence on oil. The country's population increase in recent years has led to a sharp increase in demand for energy resource products, which has negatively impacted the supply/distribution chain of these products. As a result, oil production has stagnated in recent years. Therefore, it is necessary to increase reserves and optimise production of existing fields, especially where thin sandstone deposits have been overlooked. Meanwhile, exploration geophysicists need further knowledge of the subsurface to identify economic pitfalls (Sunmonu *et al.*, 2016).

It is crucial to apply methods that minimise uncertainty in delineating stratigraphic and structural traps, as some of the mature zones from conventional seismic interpretation become dry traps during exploitation (Sunmonu *et al.*, 2016; Doust and Omatsola, 1987). Prospecting assessment involves the mapping and identification of hydrocarbon-bearing zones based on the interpretation of geophysical and geological data. Over time, thin sandstone reservoirs may have been overlooked due to the belief that the sweet spots in thin sandstones may not correspond to their commercial value. It is also believed that the cost of exploring and producing hydrocarbons from thin reservoirs is too high to be profitable. Due to the discontinuity of the reservoir during the sedimentation process, the sandstone may have become thinner, so the thin reservoir may no longer be observed laterally over a large area. This makes it difficult to visualize thin layers or beds less than 50 feet on vertical seismic sections (Harilal *et al.*, 2004), as explained by Coffen (1984) before a cost-effective method of improving the hidden features (e.g continuity of the channel could be found, etc.) When characterizing stratigraphic traps (or models), it is important to understand the complex nature of the subsurface because hydrocarbons occur in geological traps.

This work focuses on spectral decomposition through the application of fast Fourier transform methods, seismic facies and attributes in the analysis of structural and stratigraphic features in the Niger Delta Basin. Spectral decomposition is an imaging innovation that provides interpreters with high-resolution reservoir details for imaging and mapping temporal layer thicknesses and geological discontinuities in 3D seismic surveys by decomposing the seismic signal into its component frequencies. It breaks down the seismic signal into its individual frequencies (Hall, 2004). The frequency domain representation of seismic data illustrates many features that are not apparent in the time domain representation, and therefore, spectral decomposition serves as a useful tool for seismic interpreters as it also reveals stratigraphic and structural details that are often obscured in broadband data (Xiaogui and Sharma 2007; Vaneeta, 2016). This makes spectral decomposition more useful in interpreting seismic data than traditional horizon mapping and attribute extraction.

GEOLOGY OF STUDY AREA

With a long history of geological processes shaping it, Nigeria's Niger Delta Basin is a tectonically complex region. The Delta Edge, Central Swamp, Coastal Swamp, Northern Delta, Greater Ugheli, and Offshore Depobelt are the six primary structural provinces that make up the basin (Okpara *et al*., 2021). The Cretaceous fault belts or zones, which progressively developed into a network of trenches and ridges in the deep Atlantic Ocean, governed the development of these depositional belts (Okpara *et al*., 2021).

The Niger Delta began to form in the Late Jurassic and persisted into the Middle Cretaceous (Lehner, 1977). The basin is a component of a larger rift system, and the primary mechanism causing its current structural style is gravity-induced shale tectonism (Okpara *et al.,* 2021). Benin, Agbada, and Akata formations are the three stratigraphically separated Tertiary portions of the delta. The youngest formation is the Benin Formation, which is primarily made up of continental sandy facies occasionally broken up by shale deposits (Okpara *et al.,* 2021). The Agbada Formation, which has paralic deposits, grades vertically and laterally into this formation. The Agbada Formation then transitions into the marine shales of the Akata Formation offshore. These shales are thick and massive, with occasional sand deposits that are most likely turbidites. Figure 1 is a stratigraphic chart of the Niger Delta.

Situated within the Niger Delta (Figure 2), one of the world's largest delta systems, the study area is situated in the southern region of Nigeria. Hydrocarbon traps and seal formation were greatly influenced by the structural and stratigraphic evolution of the delta. Within the basin and various plays, such as Shallow or deep simple/failed rollover, K-type structures, reverse footwall termination, back-to-back structures, and inversion structures, have proven to be viable exploration targets; structural traps have also proven to be better exploration targets than stratigraphic traps.

MATERIALS AND METHODS

For this study, the dataset that was used includes a 3D seismic volume, a suite of well logs for 4 wells, and check-shot data for the four wells. Well log facies identification and well log correlation were done using wells B 3 ST 1, B 10, B 2 and B 4, and the wells were correlated in a southwest-northeast direction for the intervals corresponding to the freshwater sand of the Benin Formations, the paralic sequences of the Agbada Formation and the marine shales of the Akata Formations.

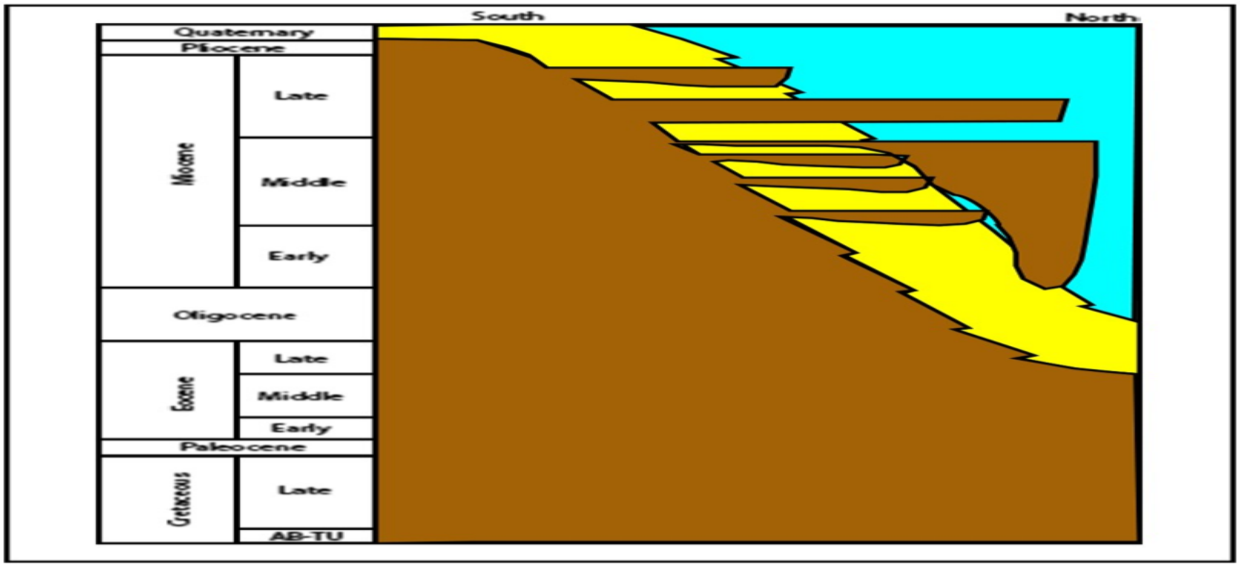

Figure 1. Simplified schematic representation of Stratigraphic column of the Niger Delta and relationship of clay filled channels on the delta flanks (Doust and Omatsola, 1990).

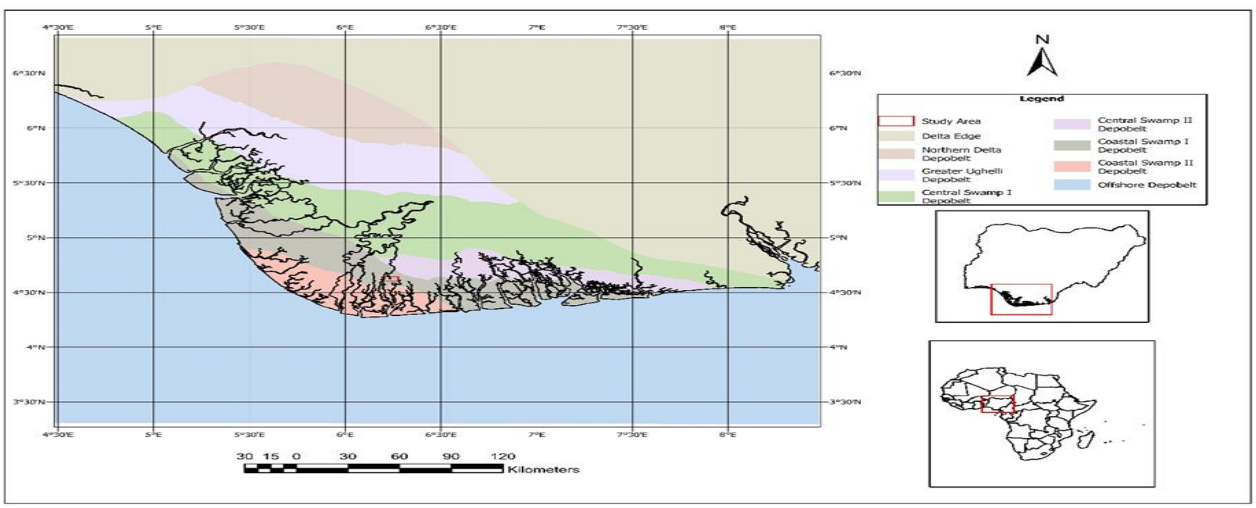

Figure 2. Location of study area in Nigeria and Nigeria in Africa and Niger Delta provinces in Nigeria (drawn after Adiela and Jayeola, 2018) and the depobelts of Niger Delta (drawn after Nwozor *et al.,* 2013 and Ebong *et al.,* 2020).

Four reservoir intervals were identified and correlated through detailed well log analysis. Seismic-to-well tie was done, which tied the well tops (reservoir and formation tops) to wells B 10 and B 2. Faults and horizons were then interpreted using the 3D seismic volume together with some derived attribute volumes to build a reliable and consistent structural framework. Seismic facies analysis was done for better characterisation of the reservoir interval. Structure maps were then generated for each of the reservoir tops, with the surface extracted from the reservoir interval posted on the maps to better characterise the reservoir interval. Spectral decomposition using the fast Fourier transform was carried out for more detailed stratigraphic analysis and the characterisation of stratigraphic features such as channels, which are also often excellent targets for hydrocarbon exploration. Figure 3 is an outline of the workflow.

RESULTS AND DISCUSSION

Formation evaluation and lithofacies identification

Three lithofacies were identified from the gamma ray log provided for this study. Included are depositional facies from various sedimentary environments. These facies are freshwater sand facies, paralic facies and marine shale facies.

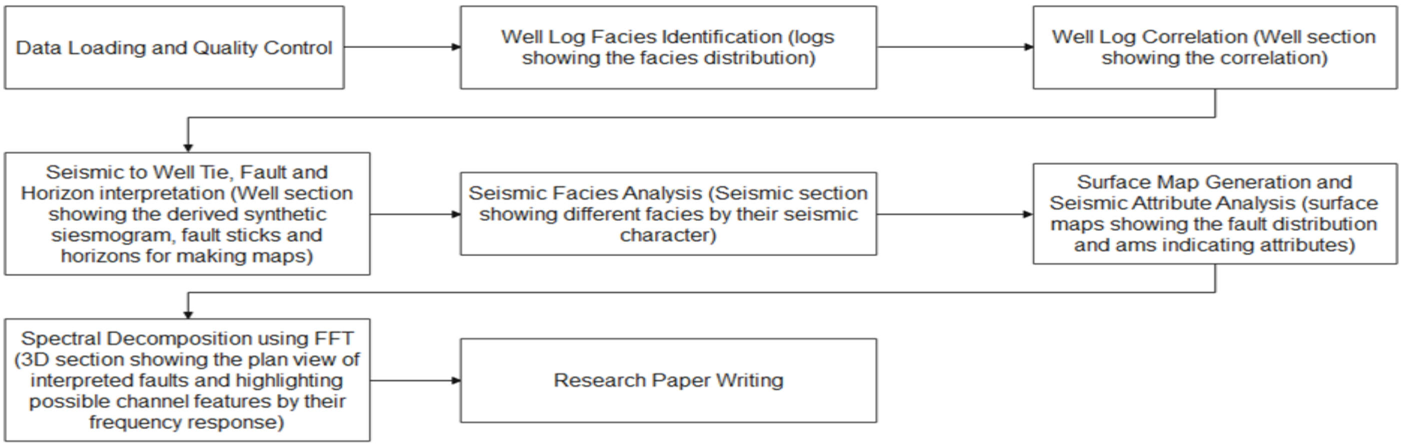

Figure 3. Outline of the workflow employed for the study.

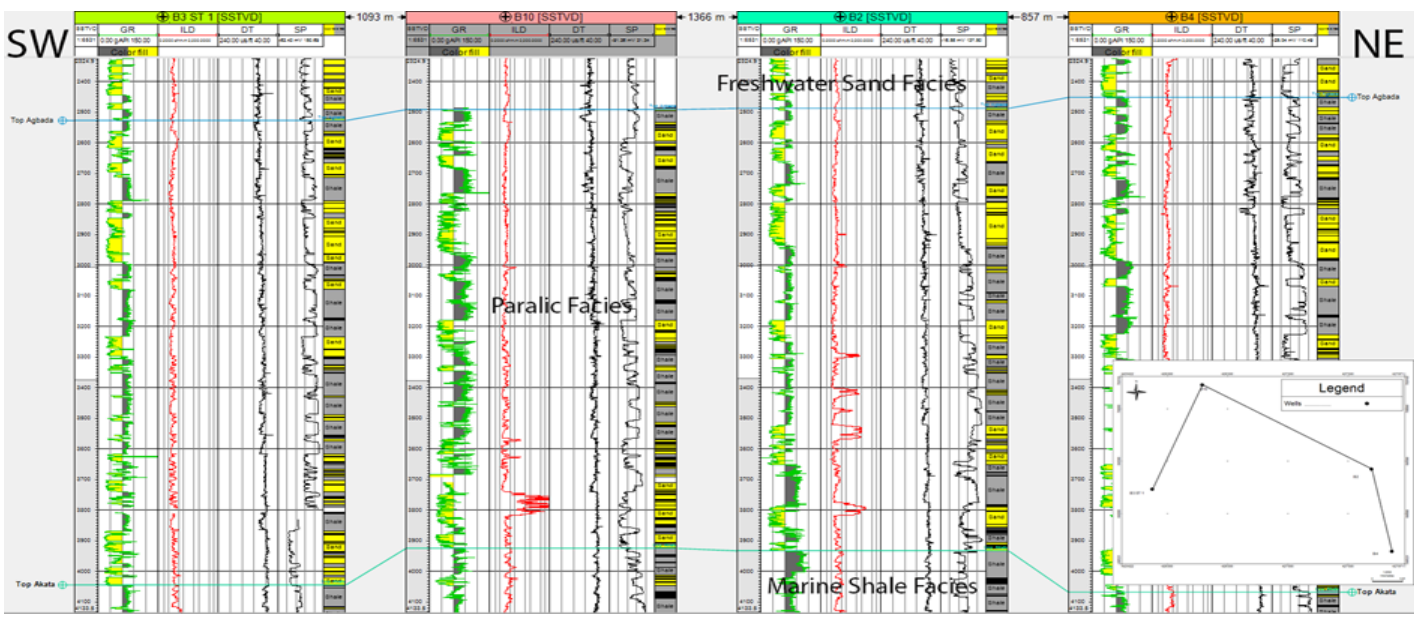

Figure 4. Well section showing the three identified Lithofacies.

Freshwater sand facies

The freshwater sand facies form the major component of the Benin Formation, the youngest stratigraphic unit in the Niger Delta, as shown in Figure 4. This lithological unit overlies the paralic Agbada Formation and covers much of the subaerial part of the Niger Delta. It appears primarily as a jagged gamma ray log pattern showing a sandier trend in the drill holes from the deeper intervals, indicating an overall increasing succession. The facies appear to be primarily sand with occasional minor shale, silt, and clay lenses, representing overbank or abandoned channel-fill facies. This sequence or unit is thinner on the flanks of the Niger Delta Basin and thicker in the offshore depocenters, a pattern consistent with the progradational depositional model described for the Niger Delta (Doust and Omatsola, 1990; Short and Stäuble, 1967). Below the field, the thicknesses in the B3 ST1, B10, B2 and B4 wells are approximately 2450 m, 2514 m, 2421 m and 2264 m, respectively, with an average thickness of approximately 2400 m. The signature of the gamma ray curve highlighted that this sequence was most likely deposited in a continental/fluviatile environment consisting of an upper coastal plain. There is evidence of meandering streams, braided rivers, and side channel deposits. In addition, splay deposits above the bank and splay deposits in crevasses are commonly found in the gamma-ray log curve signature.

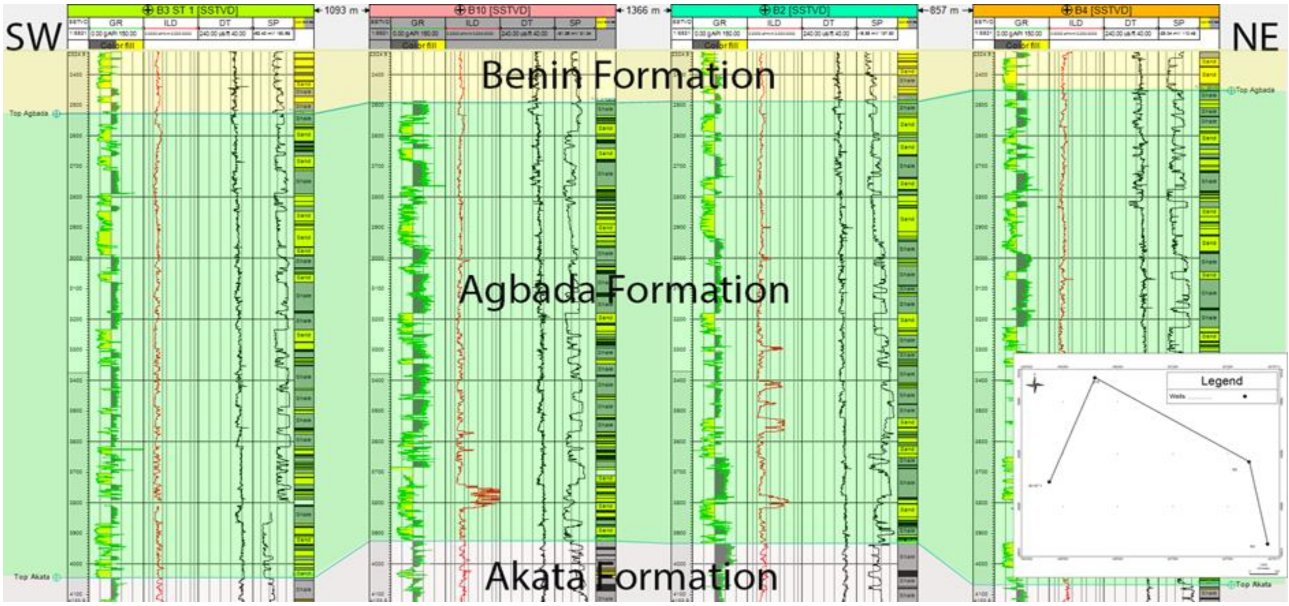

Figure 5. Correlation of the lithostratigraphic unit tops across the four wells.

Paralic facies

These facies (Figure 5) are characterised by the predominance of alternating sand and shale facies, the characteristic signature of which is referred to as “paralic”. The paralic facies form the Agbada Formation interval. The gamma-ray log signature alternates between a fining sequence and a coarsening sequence, marking the interplay between fluvial and marine-dominated systems on the delta front. This sequence or unit reaches its maximum thickness in the central depobelt before thinning toward the flanks. Towards the entry points of the depobelt, it becomes thicker and coarser, indicating increased sediment supply, a trend that aligns with the established depositional models for the Agbada Formation (Doust and Omatsola, 1990; Okpara *et al*., 2021). The paralic Agbada facies extended to the southwest and forms the primary petroleum play area. Beneath the field, the base of this unit is located at 4048 m, 3930 m, 3868 m and 4016 m in the B3 ST1, B10, B2 and B4 holes with widths of 1598 m, 1416 m, 1447 m, respectively. According to the gamma-ray log signatures, the parallel facies were most likely deposited in wave-dominated, tidally influenced deltaic environments ranging from the lower coastal plain to the shallow coast. Major depositional settings include delta fronts, distributary channels, beach ridges, barriers, tidal flats, lagoons, marshes, and tidal bays. There is evidence of interaction between river and marine processes.

Marine shale facies

The marine shale facies form the Akata Unit are present in the basal part of most wells beneath the field (Figure 4). It is predominantly shale with occasional sand deposits or units. The main environments represented in this facies unit are: submarine fans, consisting of turbiditic sandstones, siltstones and mudstones deposited by high and low density turbidity currents in an outer fan environment, basin floor and abyssal plain units, consisting of thick dark grey mudstones and siltstones, slope apron units consisting of mass transport complexes such as subsidence, landslides and debris flows shed from the continental slope, and channel- filling over bank deposits, including leveed sandstone channel systems and associated overbank mudstones and thin-bedded turbidites. This description of the Akata Formation's deep-water setting is consistent with previous work (Lehner, 1977; Doust and Omatsola, 1990). Below the field, the top of this unit is located at 4048 m, 3930 m, 3868 m and 4016 m in the B3 ST1, B10, B2 and B4 wells. The thickness is difficult to determine as not all wells penetrate to the bottom.

Well log correlation

The wells in the field were correlated in a southwest-northeast direction. It started from B3 ST1 borehole, B10 borehole, B2 borehole and B4 borehole (Figure 5).

Natural gamma radiation was used to interpret the subsurface lithology in the study area. The gamma ray log is useful for differentiating between shale-bearing formations and clean sand formations. The formation tops of three lithostratigraphic units were correlated along the southwest-northeast direction to determine the lateral continuity across the wells. The order of the formation picks was from oldest to youngest.

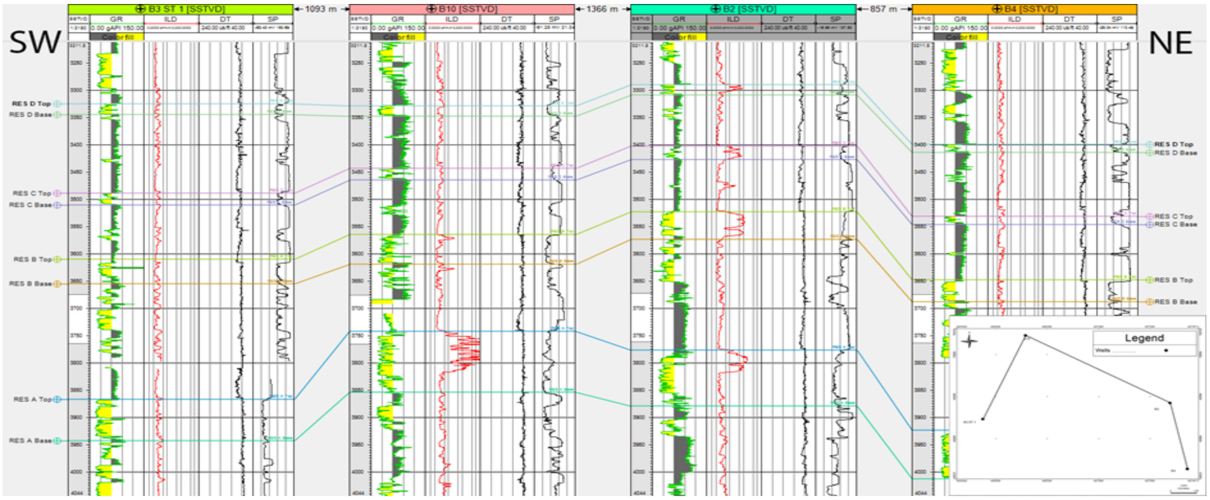

Figure 6. Well section through B3 ST1 to B4 displaying the reservoirs A to D intervals zones.

Akata formation

This is the oldest lithostratigraphic unit in the field and basin. Most drillings barely penetrated this lithostratigraphic unit. The top of the formation was correlated across the four wells: B3 ST1, B10, B2 and B4.

Agbada formation

The next correlated formation peak was the Agbada formation peak, which was present in all wells in the field. The base of this unit forms the top of the underlying Akata Formation, and the top is the base of the overlying Benin Formation.

Benin formation

Above the Agbada Formation lies the Benin Formation. It represents the youngest lithostratigraphic unit in the Niger Delta. It consists of freshwater sand facies with occasional shale fractures. The base of this unit, which coincides with the top of the lower Agbada unit, was seen in the four wells B3 ST1, B10, B2 and B4 used for correlation.

Reservoir identification and correlation

Reservoir correlation

Through detailed log analysis utilising gamma ray, resistivity, neutron, and density logs, four reservoir intervals were identified and labelled A-D in wells B3 ST1, B10, B2 and B4. These reservoir units were subsequently correlated through the wells in a southwest-northeast direction (Figure 6). Evaluation of electrical resistivity and gamma ray log signatures revealed a noticeable decrease in reservoir quality from well B10 towards well B3 ST1 and B2 towards B4 in a southwest and northeast directions, respectively. Correspondingly, the strength of the electrical resistivity response also diminished along this same trend. This is because both B3 ST1 and B4 wells are cited on the flanks of the dominant structural style in the field.

This observation aligns with seismic mapping of the reservoir unit across the field, indicating a southward dip in the structural elevation of the reservoir beds. Wells B10 and B2 represents the updip/structurally higher position, while B3 ST 1 penetrates the downdip/structurally lower portion of the reservoirs (Figure 6). Furthermore, the reservoirs do not appear to be filled to the structural spill point, which represents the lowest elevation along the plunging roll-over anticline towards the south (Figure 15). Additionally, log signatures in well B3 ST1 suggest the presence of a gas-water contact near the base of the reservoir interval. Similar trends of reservoir deterioration were observed in the other identified intervals. Finally, seismic signatures and well log analysis indicate that the trapping may involve some stratigraphic component due to lithological changes and may not be entirely structural.

Well-to-seismic tie

Connecting seismic data to well control is a crucial step in the integrated interpretation workflow. Calibration between the two data types is made possible by this connection between the subsurface characteristics found in the wells and the surface seismic measurements. First, a synthetic seismogram was created from the convolution of the sonic, density logs and a wavelet at wells B10 and B2. These synthetics model the seismic response that would be expected at the well if it were a seismic trace. The synthetic

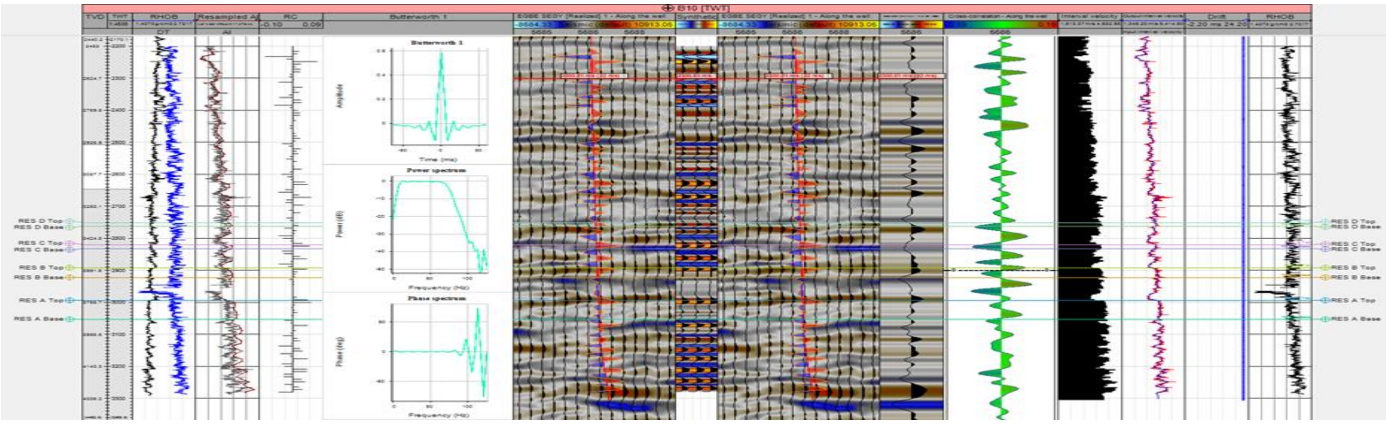

Figure 7. Synthetic Seismogram on well section used to tie the formation and reservoir tops to the seismic data for well B10.

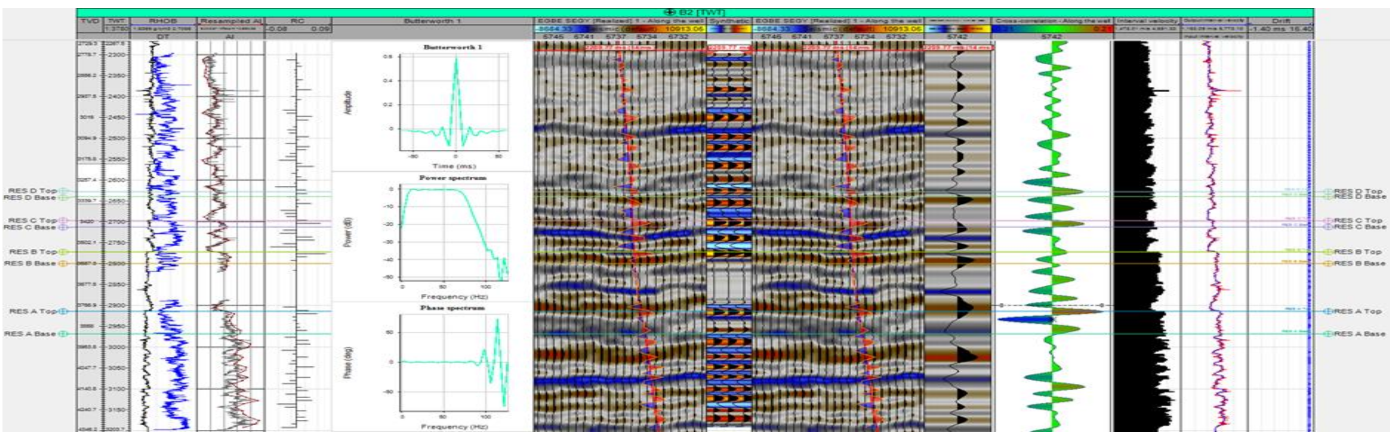

Figure 8. Synthetic Seismogram on well section used to tie the formation and reservoir tops to the seismic data for well B2.

traces were then tied or aligned to the 3D seismic volume by applying necessary time shifts, phase rotations, and filtering. This alignment ensures that seismic reflections match formation tops and lithological changes seen in the wells. The high correlation values (>0.7) achieved in this study are considered robust and are consistent with standards for reliable well-ties in similar deltaic environments (Hall, 2004; Sunmonu *et al.,* 2016).

For the current study, a total of 2 wells with sonic and density logs were available for the seismic-to-well tie process. Synthetic generation used a zero-phase Butterworth wavelet with a low cut of 4Hz and high cut of 72Hz extracted from the 3D seismic data (Figures 7 and 8). After bulk time shifts of 22ms for B10 and 14ms for B2, the maximum correlation window was scanned to optimise tie quality. Visual inspection and cross-correlation values were then used to quality control the well ties. For the two wells used, B10 and B2, an excellent tie was achieved with correlations >0.7 over the Agbada Formation interval. With a robust tie, seismic horizons were also confidently converted to depth using the time-depth relationships from sonic logs.

Structural interpretation

A structural framework was built by combining the interpreted faults and horizons over the B-field. The faults and horizons were mapped by blending the original 3D seismic amplitude volume with volumes of various seismic attributes, such as semblance and variance edge. The variance edge volume helped in the recognition of different structural zonation or zones corresponding roughly to the three lithostratigraphic intervals, Benin, Agbada and Akata Formations. The Benin, being the youngest, shows little to no tectonic disturbance or faulting (Figure 9). Most of the linear deformations are restricted to the zone which roughly corresponds to the Agbada interval (Figure 10). The Akata interval shows a more diffuse style of deformation (Figure 11). This zonation is a record of the tectonostratigraphic history and evolution of each lithostratigraphic unit and also reflects the mechanical heterogeneity of each unit.

The field is within an extensional domain, and the style of trapping is a simple faulted rollover anticline (Figure 15). The structural style is dominated by a structure controlling

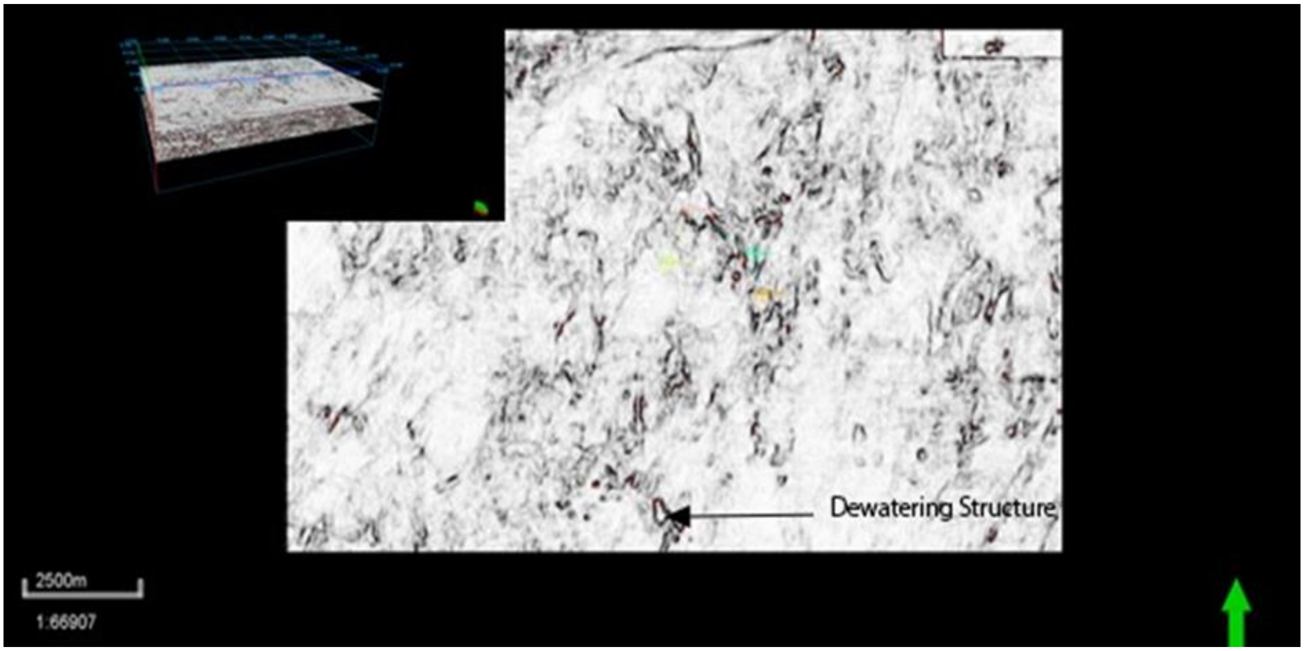

Figure 9. Time slice at 1740ms within Benin interval with less faulting.

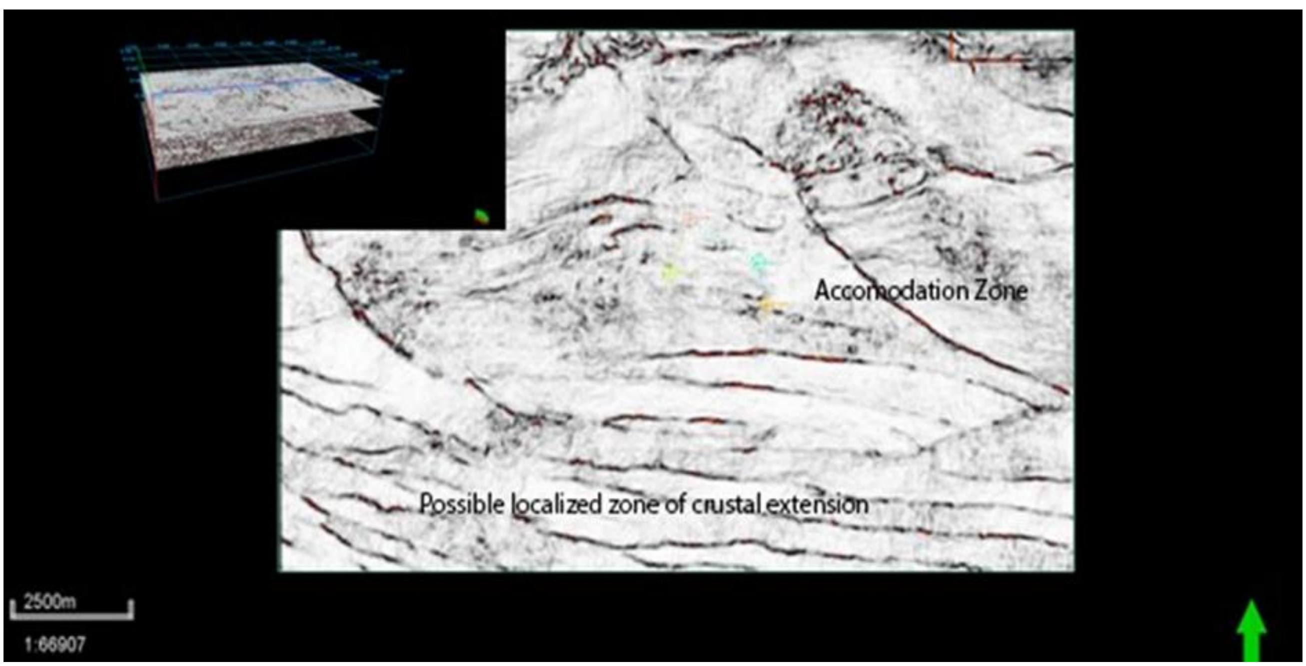

Figure 10. Time slice at 2140ms within Agbada interval, showing well defined and developed faults.

a major basin dipping normal-growth boundary fault that trends roughly east-west (Figure 17). This style of growth faulting and associated rollover anticlines is a classic structural hallmark of the Niger Delta's extensional regime (Doust and Omatsola, 1990; Okpara *et al*., 2021). There are other minor faults that are synthetic with the boundary fault and antithetic faults. Additionally, since flooding surfaces are interpreted as relatively flat depositional planes, often seen as strong reflectors with regional extent across the field, a top structure map was selected to traverse all the key structures within the field. This was utilised to establish broad displacement patterns across faults and deformation of fault blocks within the stratigraphic interval (Figures 12 and 13).

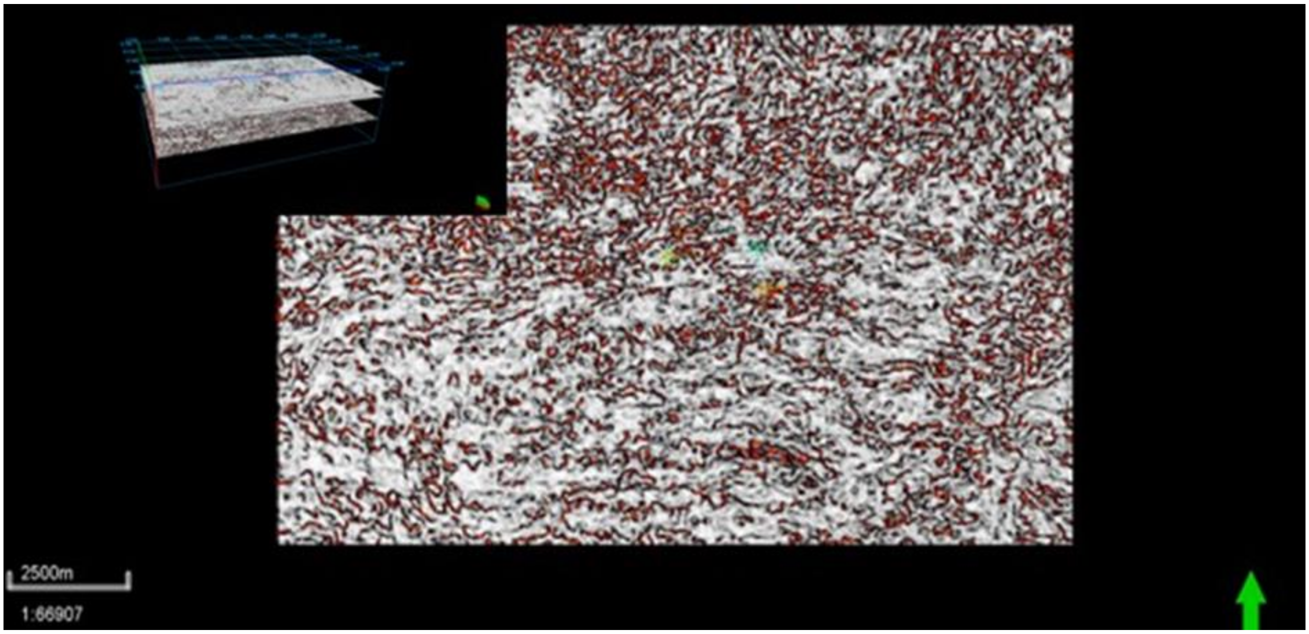

Figure 11. Time slice at 4100ms within Akata interval showing the chaotic nature of the deeper zone.

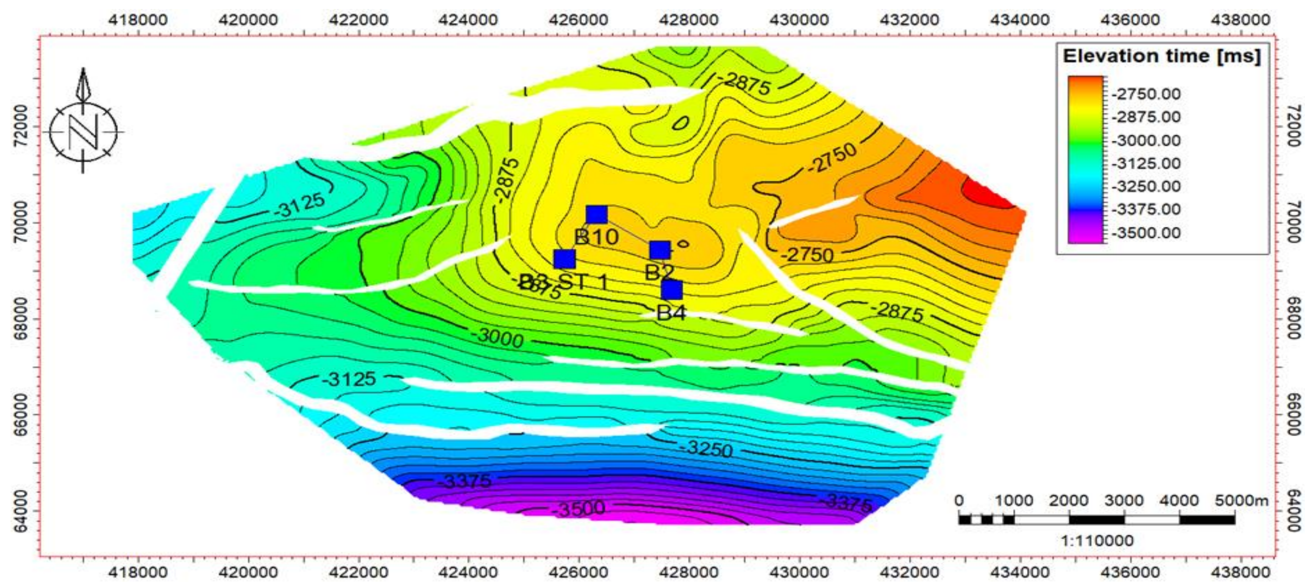

Figure 12. Time structure map for key horizon, the main northward structure controlling fault is clearly seen and other minor faults are also visible.

In the northern portion, closer to the boundary fault, the faults form splay systems and link by branching. To the south, the faults are parallel to each other. The implication of this is that the complexity of faulting and deformation reduces away from the major fault and increases towards it from the south to the north. There are principally two fault systems or sets, on the seismic dip and strike sections, the major or dominant structural style associated with the major or boundary fault, with other minor faults exhibiting the same sense of dip and orientation and a second system involving antithetic faults that are fewer in number and can be associated with accommodation to the stretching or extension during the course of the tectonic evolution of the depositional sequences. On plan view, the first fault sets exhibit an east-west trend while the second exhibits a more north-south or northwest-southeast trend (Figure 18).

On plan view, the faults show a narrow convex and

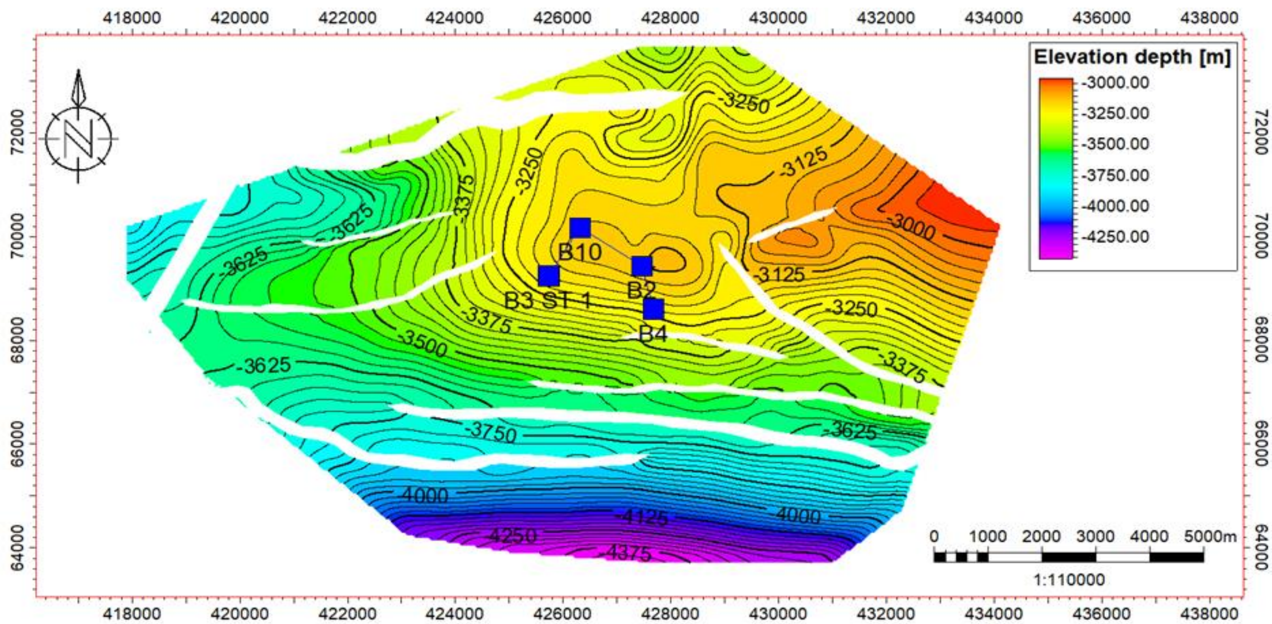

Figure 13. Depth structure map for key horizon, the main northward structure controlling fault is clearly seen and other minor faults are also visible.

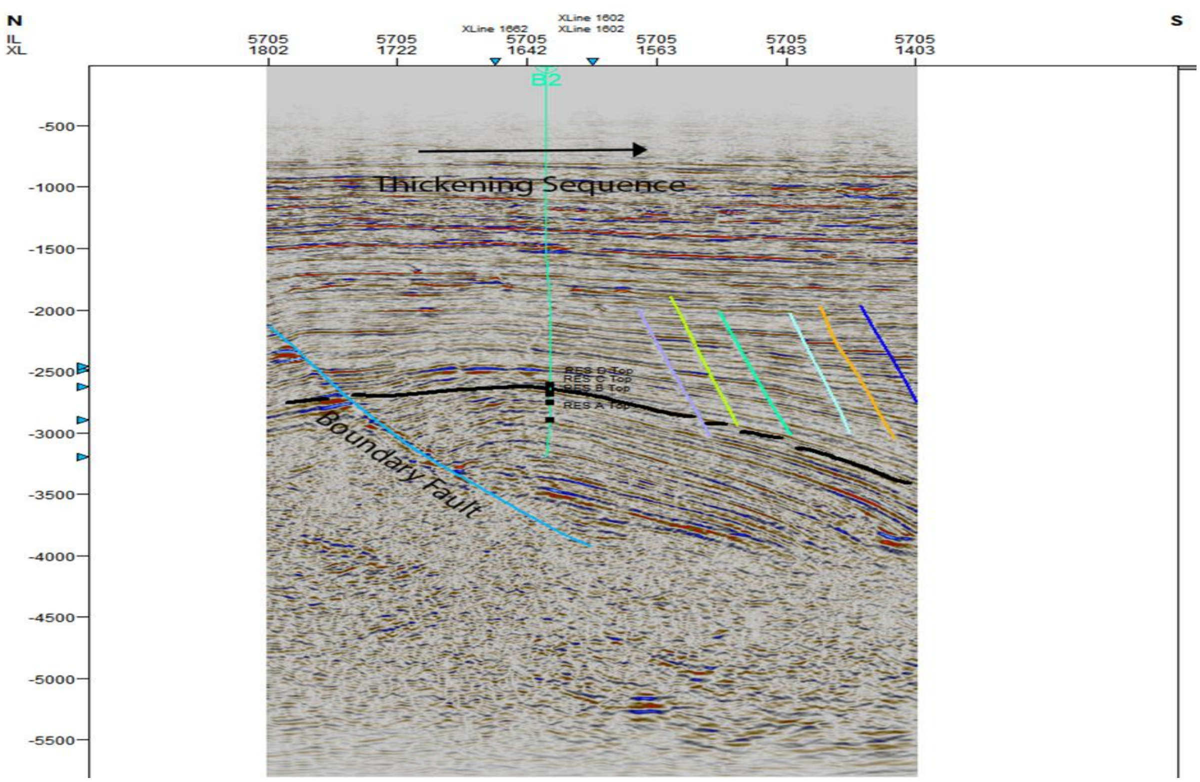

Figure 14. A seismic dip section along north-south direction showing the main structures and the dominant structural trend.

cuspate geometry along strike. Another indication of the general trend in the complexity of deformation and style is encoded by the relative fault dip. Fault dips reduce away from the major bounding fault and increase towards it. The reverse is the case for bed dip. Bed dips become steeper away from the major bounding fault and deeper in section.

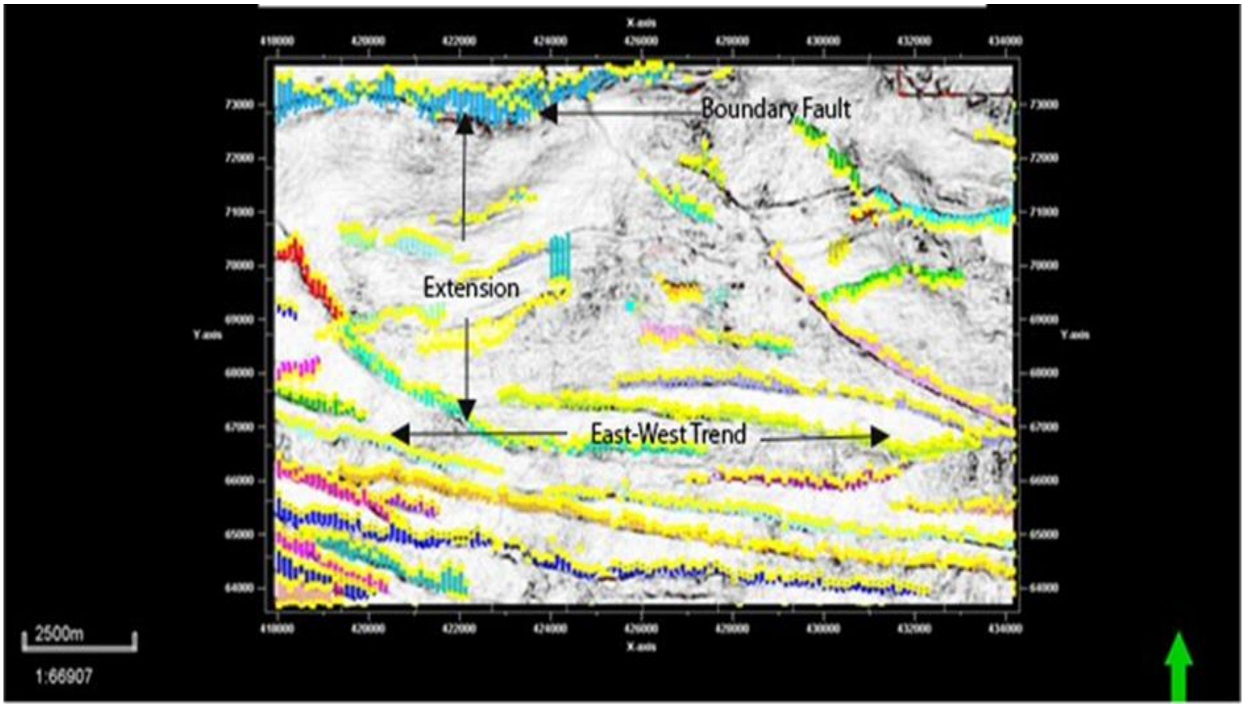

Figure 15. Time slice of variance edge volume at 2140 with the interpreted fault superimposed on it showing the plan view of the dominant structural trend and direction of extension.

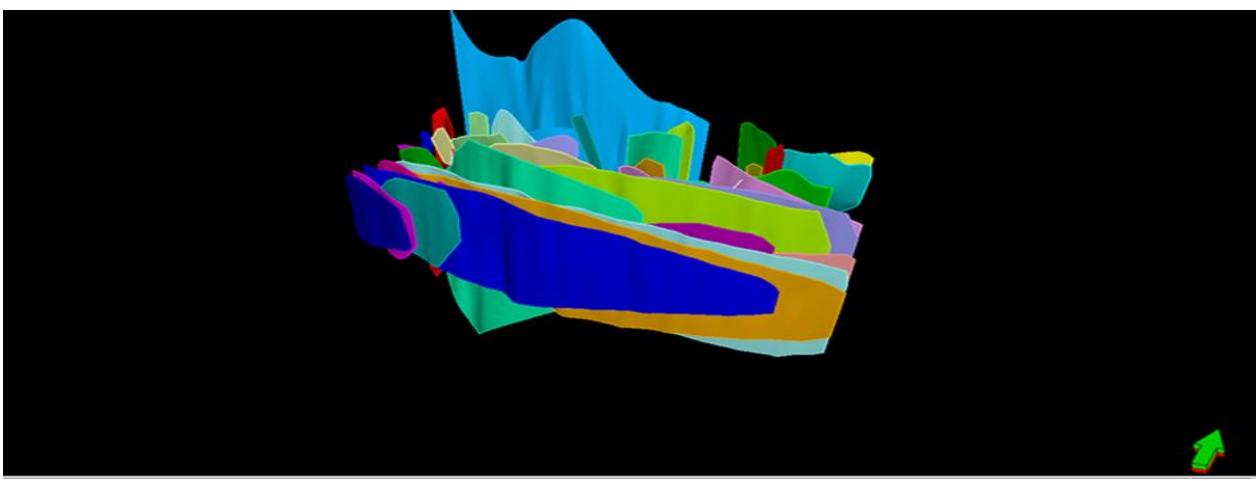

Figure 16. 3D structural framework of the fault planes for the interpreted faults indicating the dominant structural orientation.

Bed thickness also increases away and across the major fault, thins over the crest of the anticline, increases slightly, and thins progressively from north to south. There is also a clear indication for the formation of a shale wedge, which is shallower under the base of major faults and has clearly influenced and even controlled the structural evolution within the field (Figure 17). Such shale tectonism, including the formation of mobile shale wedges, is a well-documented mechanism driving deformation in the Niger Delta (Lehner, 1977; Okpara *et al*., 2021).

Seismic facies analysis

Using the seismic data collected for the study, a seismic facies analysis was performed for the field. The primary factor used to categorise seismic data into seismic facies is the nature of the reflections. Several features aid in characterising the nature of seismic reflections. The arrangement of the reflections, their continuity, their amplitude, and their frequency are the four primary characteristics that were used in this investigation.

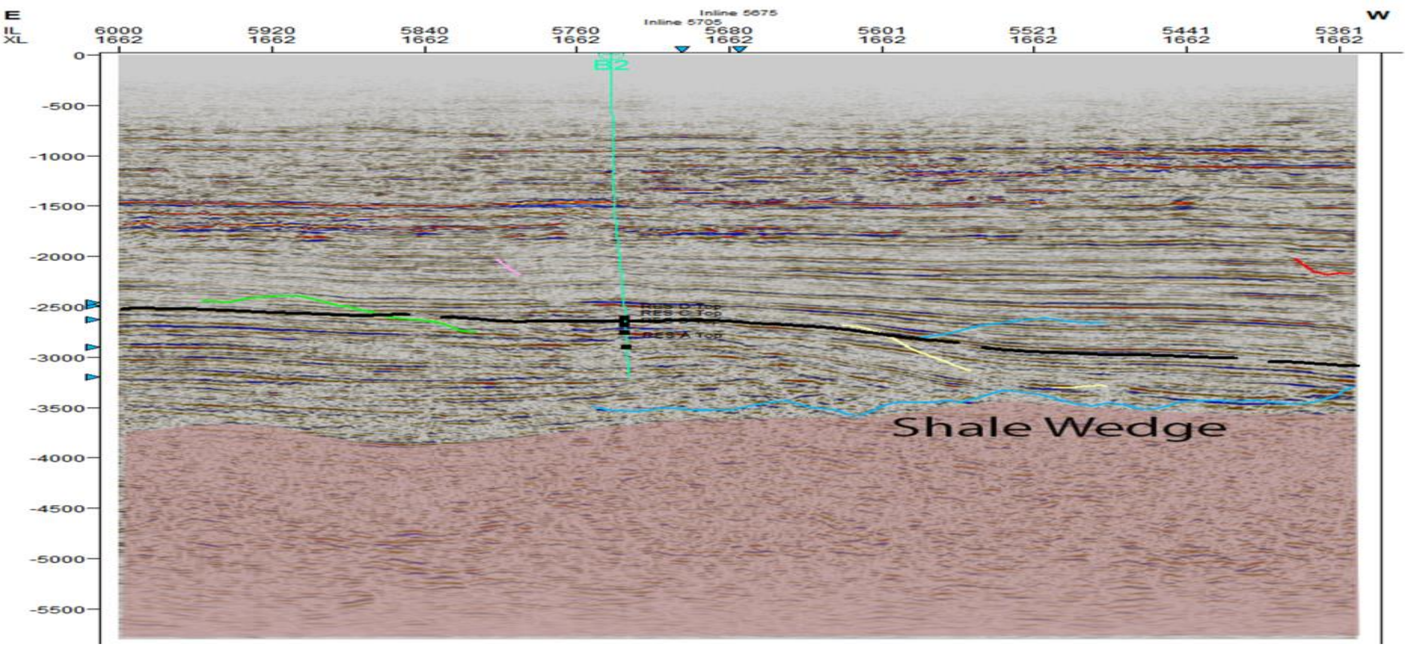

Figure 17. A seismic strike section along east-west direction showing a shale wedge.

This allowed for the identification of three primary seismic facies (designated facies I, II, and II) from the seismic data. Facies I are made up of discontinuous, high-frequency, medium to high amplitude reflections, Facies II are made up of continuous high-frequency, medium to high amplitude reflections, while Facies III are chaotic reflections mostly seen on the deeper sections of the seismic profile and progressively appear in shallow sections of the seismic profile under the base of major growth faults. Towards the southern portion of the field, in the basal sections, facies II in this section dips steeply and appears to be shingled. It passes into facies III, which becomes dominant as one moves towards the north between the interval of 3s to 3.5s on the seismic section (Figures 18 and 19).

Facies II make up the main seismic facies in the interval of interest in the study area, which is between 1.7 and 4s TWT (two-way-travel time). This interval was interpreted from regional studies to be the Agbada Formation (Short and Stäuble, 1967; Doust and Omatsola, 1990). There are logs for this interval in most of the wells in the study area. Facies log generated from the gamma ray logs from the wells shows gamma ray values and facies variations characteristic of the Agbada Formation. Most of the reflections in this interval show distortions along the fault plane of the growth fault, which runs through this interval. Reflections in the shallowest part of this interval are mainly of the facies I type and are parallel to sub-parallel away from the fault and towards the faults appear to rollover onto the fault planes, giving the interval a general rhombus configuration or shape. In the deeper section of this interval, the seismic facies change from predominantly type I to II, but there are visible lateral variations in seismic facies observable in the section.

Seismic facies I and II can be related in a general way to characteristic log trends described above under the well log interpretation. The base of an interval of seismic facies I is defined by an abrupt change to relatively low-value gamma ray upward-fining or blocky log signatures, interpreted to reflect an abrupt coarsening. Seismic facies II deposits are generally finer grained and commonly comprise the basal parts of upward-coarsening or the upper parts of upward-fining well log successions. Particularly high amplitude and continuous reflections within facies II are commonly associated with relatively thick intervals with uniformly high gamma ray values, inferred to record thick shales.

Seismic attribute analysis

Figures 20 to 23 show the top structure maps for each reservoir unit with the seismic envelope attribute extracted on it. High-amplitude anomalies are observed on a structural high, which may indicate the presence of hydrocarbon accumulations or changes in reservoir properties. The high amplitude anomalies show some structural conformity. But the distribution of the anomaly strongly indicates the heterogeneity of the reservoir. The use of the envelope (reflection strength) attribute to identify bright spots related to potential hydrocarbons is a common and effective practice in the Niger Delta and other basins (Sunmonu *et al*., 2016; Harilal *et al.,* 2004).

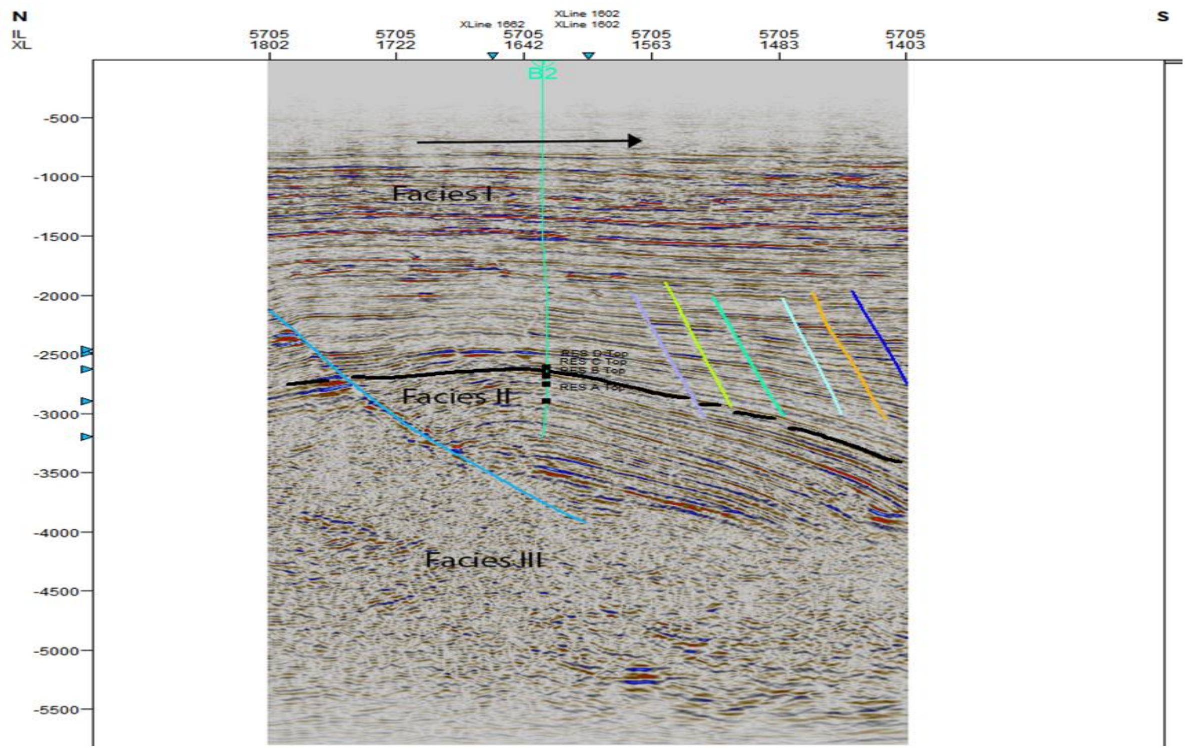

Figure 18. Seismic dip section showing the different seismic facies identified on the seismic data.

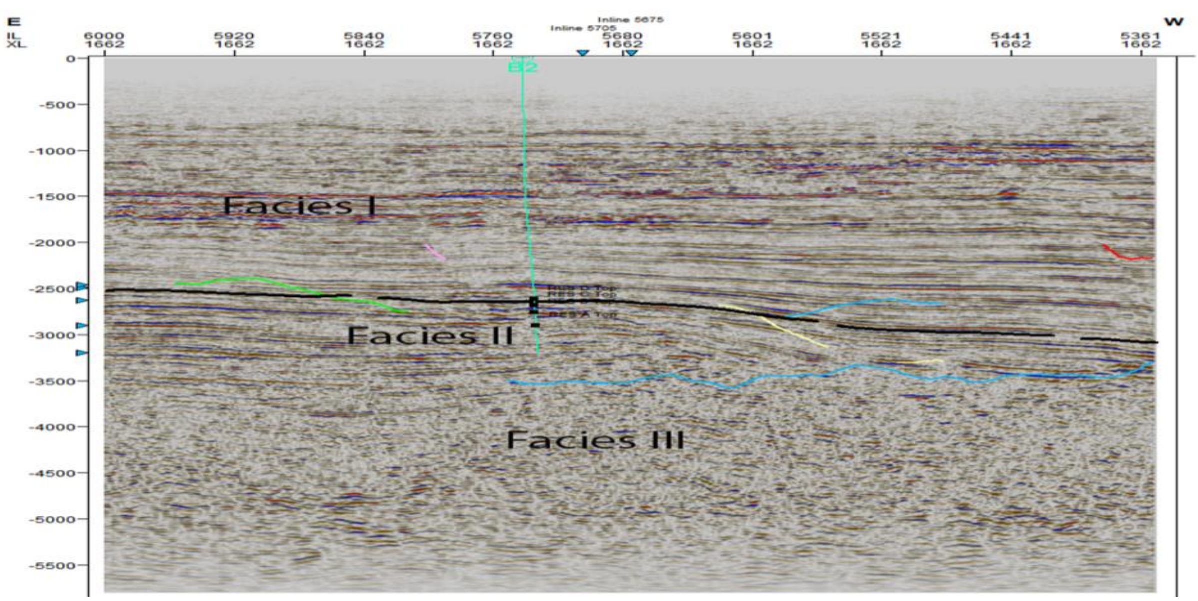

Figure 19. Seismic strike section showing the different seismic facies identified on the seismic data.

Spectral decomposition

Stratigraphic characterisation using spectral decomposition

Locating and defining channel features in complex deltaic sedimentary environments, which often serve as secondary exploration targets for hydrocarbons, may be very challenging and difficult. Detailed stratigraphic characterisation often requires that the geometries of such features are accurately defined. Difficulties in clearly differentiating between individual channel bodies and their

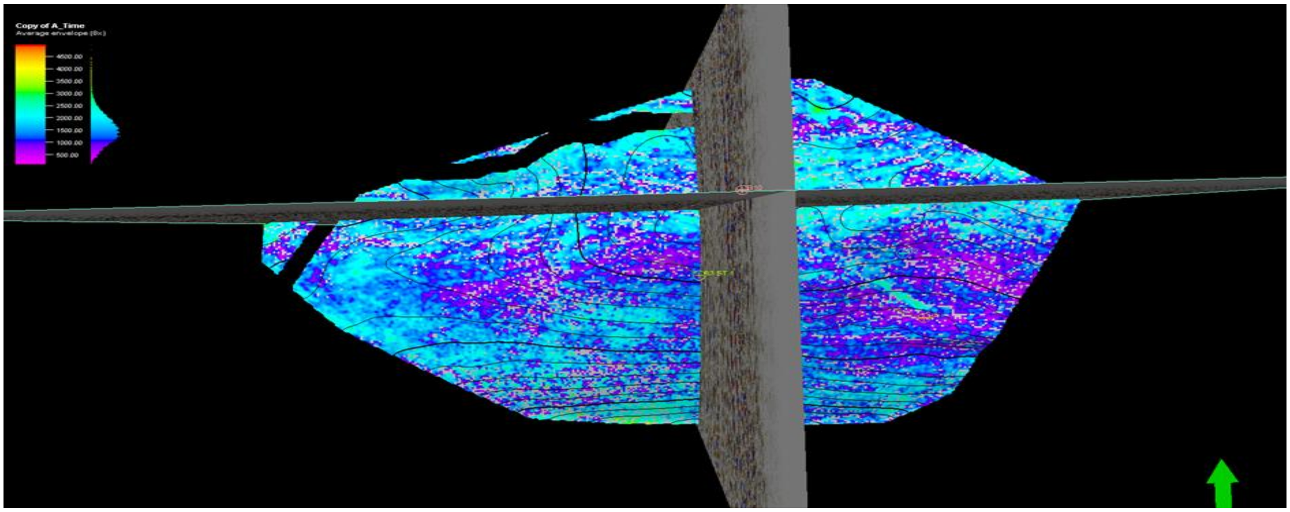

Figure 20. Top structure map for reservoir A with the envelope attribute extracted on it.

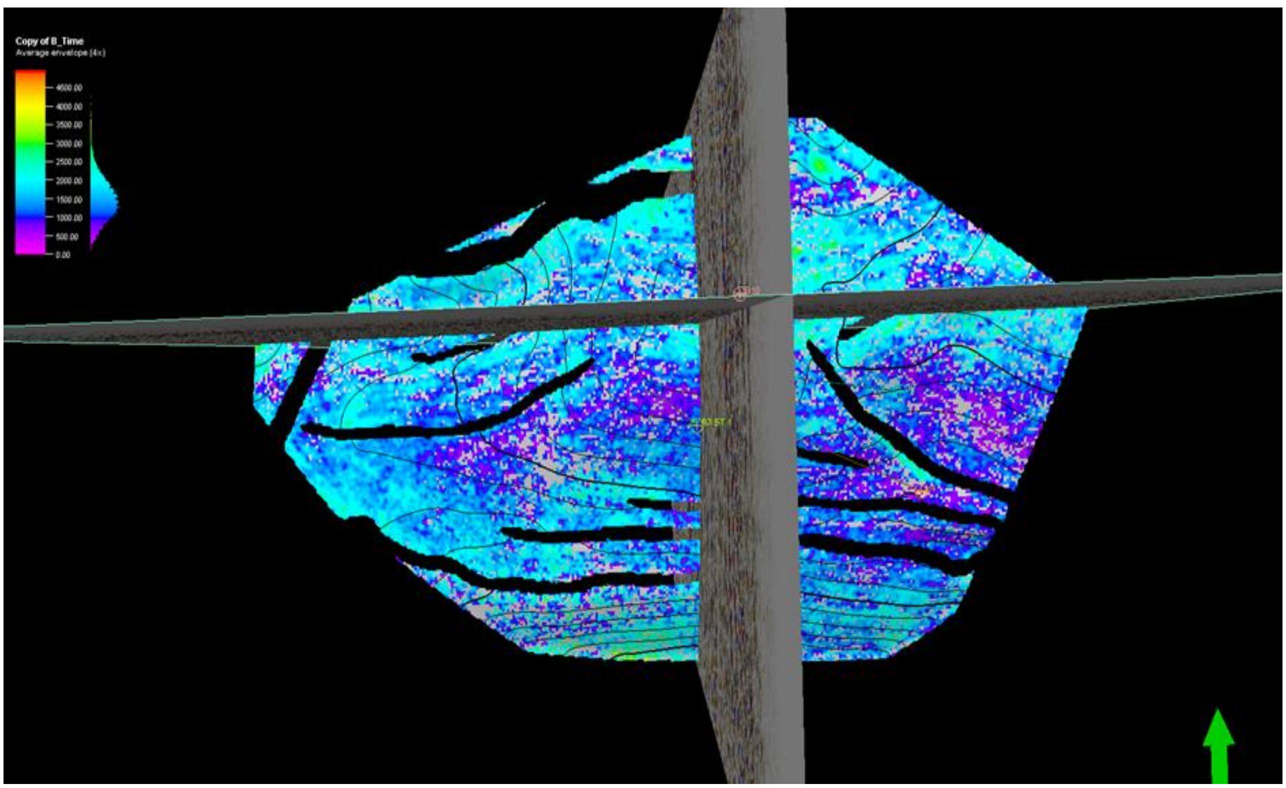

Figure 21. Top structure map for reservoir B with the envelope attribute extracted on it.

associated architectural elements abound during conventional seismic interpretation techniques. This is as a result of the heterogeneous and laterally discontinuous nature of deltaic sequences.

To overcome these, spectral decomposition has proven to be a useful technique. Breaking down the broadband seismic signal into several narrowband frequency components that can each be independently analysed and visualised, spectral decomposition can be considered a seismic processing method. Through this frequency-domain analysis, distinct spectral signatures that may be associated with various geological features, such as channel sands, overbank deposits, and sediments dominated by mud, can be characterised. The effectiveness of spectral decomposition for channel delineation in complex deltaic settings has been demonstrated in several

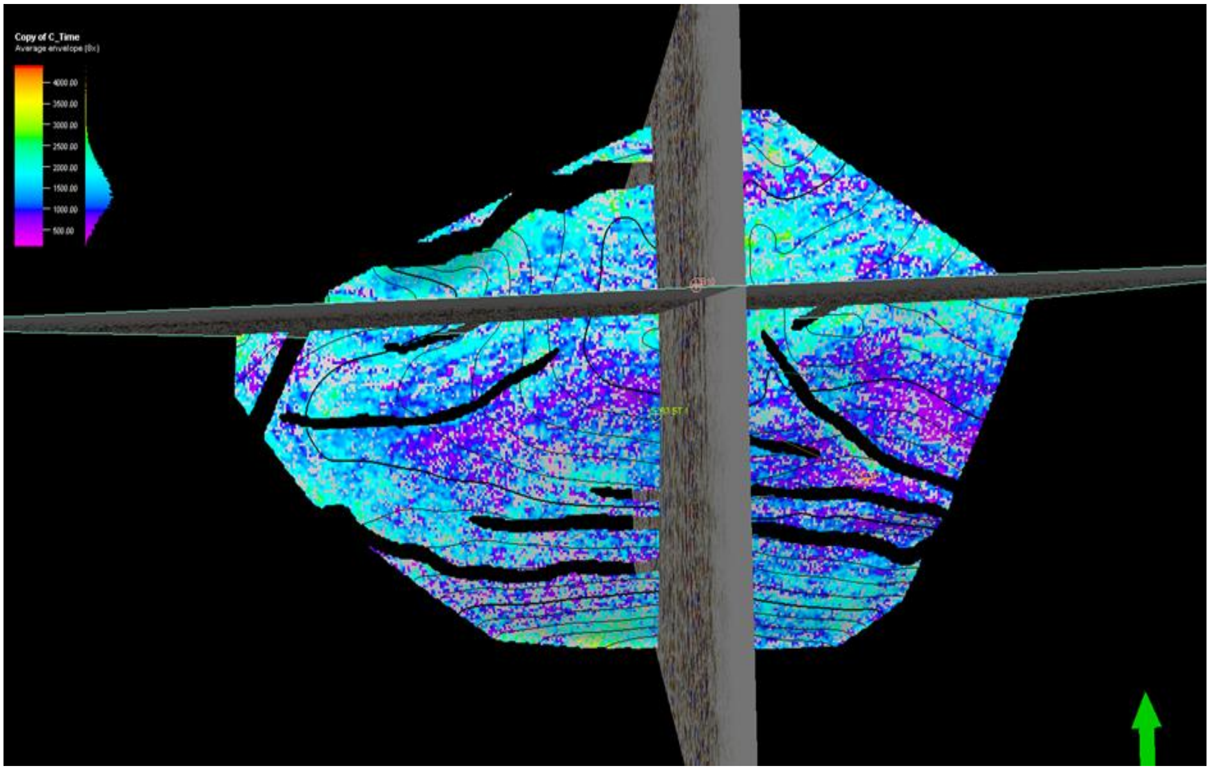

Figure 22. Top structure map for reservoir C with the envelope attribute extracted on it.

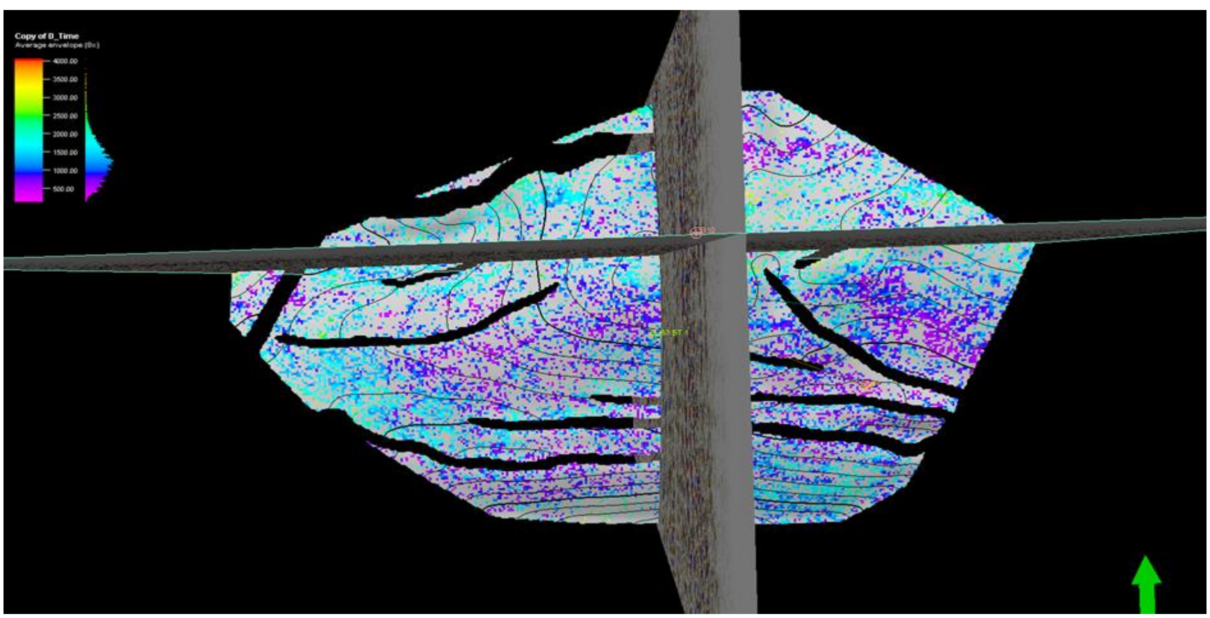

Figure 23. Top structure map for reservoir D with the envelope attribute extracted on it.

studies (Hall, 2004; Xiaogui and Sharma, 2007; Vaneeta and Sharma, 2016).

The fast Fourier transform method was used to decompose the seismic data into signals of interest of varying frequencies. Three frequencies were extracted (15Hz, 30Hz and 45Hz). This was after the seismic data were analysed to determine the dominant frequencies. 15Hz was used to represent low frequency events, 30Hz for mid and 45Hz for the higher frequency features. Individually, these frequency volumes show very little

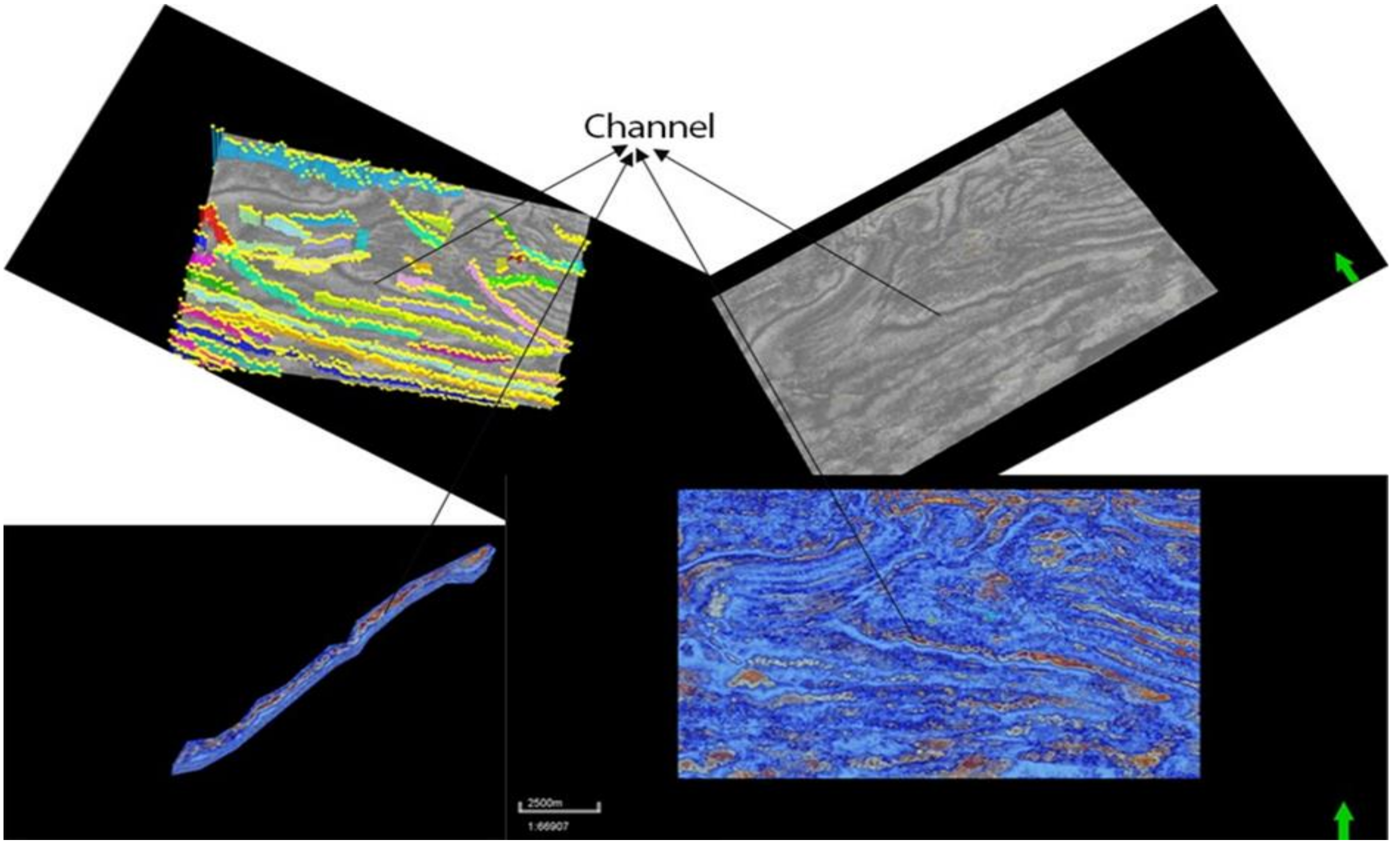

Figure 24. Spectrally decomposed volumes coblended into an RGB volume, some channel features are clearly visible.

features that could be of interest, but when coblended into an RGB volume, features such as channels are better highlighted (Figure 24). The channel system can clearly be seen to be a braided stream or river system. The RGB blending technique is particularly powerful for visualising the spatial distribution and geometry of channel systems, as their tuning effects vary across frequencies (Xiaogui and Sharma, 2007).

Conclusion

This study demonstrates the utility and use of spectral decomposition as a means of revealing hidden features in seismic data in complex sedimentary environments. Conventional seismic interpretation techniques are often limited, especially in situations where the hydrocarbon exploration objectives or targets are stratigraphic traps. The results of the spectral decomposition reveal a braided river or stream system. Structural analysis also shows a roll-over anticline, together with the river systems provide excellent conditions for the development of viable hydrocarbon traps with good reservoirs. Four reservoir intervals have been identified and correlated, with well log facies and seismic attribute analysis indicating heterogeneity and the complex nature of the reservoirs.

CONFLICT OF INTEREST

The authors declare that they have no conflict of interest.

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