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Hydrocarbon Recovery Enhancement and Well Placement Optimisation through Integrated Flow Pathway and Reservoir Connectivity Analysis in a Faulted Field

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Abstract

Hydrocarbon recovery in a faulted field is strongly influenced by reservoir connectivity, fault seal behaviour, and fluid flow pathways. This study evaluates the impact of structural compartmentalization on reservoir performance and well placement optimization through an integrated analysis of fault architecture, reservoir correlation, and flow pathway characterization within a faulted hydrocarbon field. Four wells (X01, X02, X03 and X04) were examined for reservoir continuity, fault-controlled connection and implications for field development. The results of the reservoir correlation indicated the presence of two main reservoir units throughout the studied region. Wells X01, X03 and X04 show high lateral continuity, thicker development of sandstones and good reservoir quality. Well X02 is characterised by a deeper occurrence of the reservoir, lower thickness of sand and increased shale content. Structural study has shown four faults (F1–F4) that exert strong control on the architecture and connectivity of the reservoir. F1 and F2 are the main structural features, and F3 and F4 are minor faults. The most important fault, F1, with the greatest throw, separates the deeper downthrown X02 compartment from the structurally elevated and interconnected X01–X03–X04 reservoir system, but F2 retains connectivity within the latter compartment. The fault seal assessment shows that faults F1, F3, and F4 are sealing faults, but F2 is a non-sealing fault due to sand-on-sand juxtaposition. The seal F1 gives X02 good isolation from the associated reservoir system, and therefore compartmentalization and limited fluid contact. Flow pathway study shows that the connectedness of reservoirs in the X01–X03–X04 compartment facilitates efficient fluid migration and pressure communication, and therefore enhances the recovery capacity. The isolated X02 compartment offers less connectivity and development opportunities. The paper indicates that integration of fault seal analysis, reservoir connectivity assessment and flow channel characterization provides a robust structure to optimize well location, minimise development uncertainty and enhance hydrocarbon recovery in structurally complex reservoirs.

Keywords: Hydrocarbon Recovery, Faulted Field, Fluid Flow Pathways, Structural Compartmentalisation. Well Placement Optimisation.

Introduction

The recovery of hydrocarbons from mature and structurally complex reservoirs is increasingly dependent upon a robust understanding of the reservoir architecture, fluid-flow pathways, and connections across producing intervals. Reservoir characterisation involves the synthesis of geological, geophysical, and petrophysical data to establish the spatial distribution of reservoir attributes and to forecast fluid flow behaviour in the subsurface. Accurate characterisation is particularly important in faulted deltaic systems where reservoir heterogeneity, compartmentalisation and structural complexity have a profound effect on hydrocarbon production performance (Doust and Omatsola, 1990; Fossen, 2016).

The Niger Delta Basin of southern Nigeria is one of the world's most prolific hydrocarbon provinces, with several huge oil and gas fields that are mostly within the Agbada Formation (Evamy et al., 1978; Kulke, 1995). Decades of research and production have resulted in the discovery of multiple reservoirs in the basin, which nevertheless pose issues of reservoir compartmentalization, uncertain connectivity, and poor drainage due to complicated fault topologies. These issues often result in sub-optimal well location, bypassed hydrocarbons and lower recovery efficiency.

Depositional architecture and structural deformation interact to determine reservoir connectivity. Growth faults, rollover anticlines, shale streaks, and stratigraphic discontinuities can either promote hydrocarbon migration or act as sealing barriers to prevent fluid communication (Corredor et al., 2005; Bretan et al., 2003). More recent studies also indicate that combining seismic interpretation, fault seal analysis and petrophysical characterisation greatly enhances the prediction of reservoir connectivity and the optimisation of well placement in fractured reservoirs in the Niger Delta.

In recent investigations, integrated seismic and petrophysical analysis has been proved to be beneficial in Niger Delta reservoirs. Opara et al. (2011) showed that structural traps related to growth faults and rollover anticlines are important factors controlling hydrocarbon accumulation and reservoir dispersion. Seismic-to-well links are crucial instruments for improving horizon mapping and reservoir prediction, as demonstrated by Adeoti et al. (2014) and Oyeyemi and Aizebeokhai (2015). More recently, Ismaila et al. (2023) used 3D seismic structural interpretation to find fault-controlled hydrocarbon traps in the Niger Delta, while Omijie et al. (2024) showed the usefulness of seismic inversion and net-to-gross estimation to improve reservoir models and hydrocarbon volume estimates. Waliezi et al. (2022) also used well-log data analysis to identify hydrocarbon-bearing zones and evaluate source-rock potential. At field scale, petrophysical investigations by Azubuike-Ijomah et al. (2017) found the reservoirs inside the Niger Delta Field with favourable reservoir attributes characterised by high porosity, substantial permeability and significant hydrocarbon potential. Their study highlighted the necessity of integration of petrophysical and geological data in the appraisal of reservoirs and planning of field development. However, these developments have not resulted in many studies that can holistically combine structural interpretation, fault analysis, petrophysical characterisation, and reservoir connectivity assessment to optimise well placement and improve hydrocarbon recovery in faulted Niger Delta reservoirs. Field 'X' in the Coastal Swamp Depobelt of the Niger Delta (Fig. 1) is a good case study for assessing the effect of fault architecture and reservoir connectivity on production performance.

The study area is located in the eastern coastal Niger Delta Basin, near Port Harcourt, Rivers State, Nigeria, approximately between latitudes 4.4°N and 4.7°N and longitudes 6.6°E and 6.8°E. The name Field 'X' is actually used in this study to comply with SPDC's confidentiality policy of withholding the actual field name. The field is characterised by stacked sandstone reservoirs, extensive growth fault systems, and significant lateral heterogeneity, all of which affect fluid communication and reservoir drainage efficiency. Understanding the distribution of flow pathways and the degree of connectivity between fault-bounded reservoir compartments is therefore critical for identifying undrained reserves and improving well placement decisions.

Accordingly, this study investigates the structural controls on reservoir connectivity and fluid-flow pathways in Field 'X' through the integration of seismic interpretation, well-log analysis, and reservoir characterisation techniques. The research seeks to improve understanding of fault-controlled compartmentalisation, reduce uncertainty in reservoir prediction, and establish a framework for optimising well placement and enhancing hydrocarbon recovery. The outcomes are expected to contribute to more effective reservoir management strategies within the Niger Delta and other structurally complex deltaic petroleum systems worldwide.

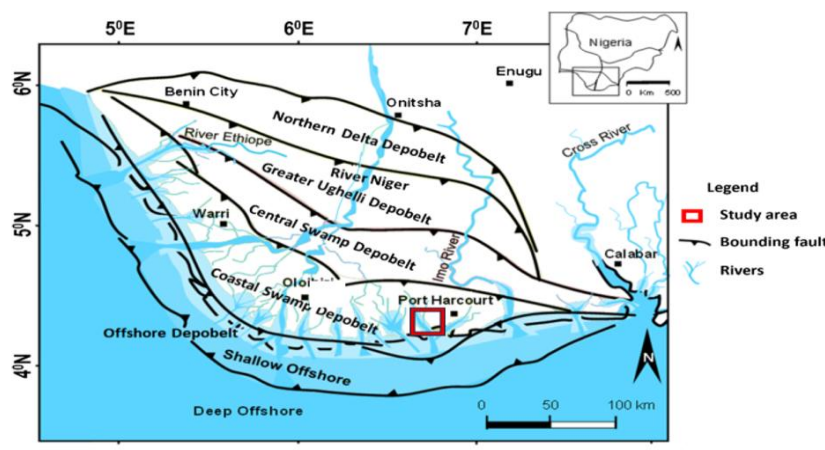


Fig. 1: Map of Niger Delta Basin showing location of study Area (Field 'X') (Modified from Izuchukwu et.al., 2022).

Geological framework

Regional Geological Setting of the Niger Delta Basin

The Niger Delta Basin represents one of the world's largest and most prolific Tertiary delta systems, located along the passive continental margin of the Gulf of Guinea in West Africa. It covers an area exceeding 300,000 km² and contains sedimentary successions that locally exceed 10–12 km in thickness (Stacher, 1995). The basin evolved as a result of the Early Cretaceous separation of the African and South American plates, which initiated the development of a passive margin basin system along the Equatorial Atlantic (Burke et al., 1972; Whiteman, 1982).

Thermal subsidence after rifting from the Paleogene to the present and a constant supply of sediments from the original Niger-Benue River system resulted in continual filling of the basin. This long-lived progradational history led to a thick wedge of clastic sediments with frequent coastline migrations, fast lateral facies shifts and substantial depositional heterogeneities. The Niger Delta is characterised by a diachronous progradation, resulting in a sequence of discrete depobelts in terms of structure and stratigraphy. These depobelts (Northern Delta, Greater Ughelli, Central Swamp, Coastal Swamp and Offshore) show various episodes of basinward migration of depositional loci through time. Each depobelt has different structural types and reservoir layouts, which directly control hydrocarbon trapping and connection.

Stratigraphic Architecture and Petroleum System Stratification

The Niger Delta stratigraphy is classically subdivided into three major lithostratigraphic units: the Akata, Agbada, and Benin Formations (Short and Stauble, 1967; Avbovbo, 1978). These units represent a tripartite depositional system reflecting a transition from deep marine to continental environments and collectively define the basin's petroleum system architecture.

Akata Formation (Source and Mobile Shale Unit)

The Akata Formation forms the basal unit of the deltaic succession and consists predominantly of deep marine prodelta shales with minor turbiditic sandstones (Weber and Daukoru, 1975). These shales are organic-rich, containing Type II and Type III kerogen, and are widely recognised as the primary hydrocarbon source rock of the basin (Ekweozor and Daukoru, 1984; Tuttle et al., 1999). A critical feature of the Akata Formation is its overpressured nature, resulting from rapid sediment loading and undercompaction. This overpressure has significant implications for both structural deformation and fluid migration. Importantly, the ductile behaviour of overpressured Akata shales provides a detachment surface for gravity-driven deformation, facilitating the development of growth faults and shale diapirs that strongly control reservoir compartmentalisation and connectivity.

Agbada Formation (Reservoir and Seal Interbedding System)

Overlying the Akata Formation is the Agbada Formation, which constitutes the principal hydrocarbon reservoir unit in the Niger Delta (Short and Stauble, 1967; Evamy et al., 1978). It comprises alternating sandstone and shale sequences deposited in a range of deltaic environments, including distributary channels, mouth bars, tidal channels, delta front, and shallow marine settings.

The Agbada Formation exhibits pronounced vertical and lateral heterogeneity due to rapid facies transitions and frequent channel avulsion events (Amajor, 1991). Reservoir sandstones typically display good petrophysical properties, with porosities ranging from 20–35% and high permeability values, although these properties are strongly facies-dependent and diagenetically modified. Importantly, intraformational shales within the Agbada Formation act as both baffles and seals, leading to complex internal reservoir segmentation. This stratigraphic heterogeneity plays a fundamental role in controlling fluid flow pathways and directly influences well productivity and sweep efficiency—key considerations in well placement optimisation.

Benin Formation (Hydrogeological Overburden Unit)

The Benin Formation represents the uppermost unit of the Niger Delta sequence and consists predominantly of unconsolidated fluvial and alluvial sands deposited in continental environments (Short and Stauble, 1967; Avbovbo, 1978). It is largely non-marine, highly porous, and functions primarily as a regional aquifer system. Although generally non-reservoir-bearing in petroleum systems, the Benin Formation plays an indirect role in pressure distribution and near-surface fluid dynamics, which can influence drilling behavior and shallow connectivity interpretation.

Structural Framework: Growth Faulting and Gravity Tectonics

The structural evolution of the Niger Delta is dominated by gravity-driven tectonics resulting from rapid sediment loading on weak, overpressured Akata shales (Xiao and Suppe, 1992) (Fig.2). This process generated a linked extensional-compressional system comprising updip extensional growth faults and downdip toe-thrust structures (Corredor et al., 2005; Bilotti and Shaw, 2005). Listric growth faults represent the most significant structural elements controlling reservoir architecture and hydrocarbon entrapment. These faults are syndepositional in nature and exhibit increasing displacement with depth, flattening into detachment surfaces within the Akata Formation (Doust and Omatsola, 1990; Stacher, 1995). Their syndepositional movement created accommodation space that influenced sediment thickness variations, facies distribution, and reservoir stacking patterns.

Associated structural features include rollover anticlines, fault splays, synthetic and antithetic faults, and collapse structures (Weber and Daukoru, 1975; Corredor et al., 2005). These structures form the primary trapping configurations in the basin. From a reservoir engineering perspective, growth faults are particularly important because they simultaneously act as:

- Migration pathways facilitating hydrocarbon charge from Akata source rocks;
- Sealing barriers or conduits, depending on fault rock properties;
- Compartmentalisation boundaries controlling pressure communication and sweep efficiency.

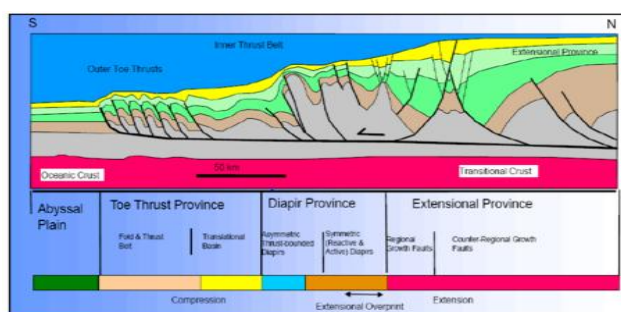


Fig. 2: Niger Delta Basin schematic seismic section showing the results of gravity tectonics on sediments (after Olabode et al. 2010).

Fault seal behaviour is governed by shale smear potential, clay content, fault juxtaposition, and diagenetic sealing processes (Yielding et al., 1997; Lindsay et al., 1993). These properties introduce strong spatial variability in connectivity, which directly impacts well performance and field recovery efficiency.

Implications for Reservoir Connectivity and Well Placement

The geological evolution of the Niger Delta has produced reservoirs that are inherently heterogeneous and structurally compartmentalised. The interaction between depositional facies architecture and syndepositional faulting creates a complex network of potential flow barriers and conduits.

Consequently, optimal well placement in Niger Delta reservoirs requires an integrated understanding of both structural framework and depositional architecture. Conventional structural high targeting is often insufficient, as it does not account for fault-controlled segmentation and internal reservoir heterogeneity.

Methodology

Wells Positioning: The Petrel cross-sectional display (Fig. 3) shows the spatial arrangement of wells across Field 'X'. Wells X01, X03, and X04 are positioned relatively close to each other along the same lateral trend on the section. These wells appear to align within a similar structural level and are grouped within the same general area of the cross section. Well X02 is positioned farther away from the X01–X03–X04 cluster. It is located at a lower structural level on the cross section compared to the other three wells and shows a clear separation in both lateral and vertical position. Overall, the section displays two distinct well groupings: a closely spaced cluster comprising X01, X03, and X04, and a more distant, deeper-positioned well represented by X02.

Well Log Interpretation and Reservoir Correlation

Reservoir characterisation began with detailed interpretation of wireline logs to identify lithofacies and hydrocarbon-bearing intervals within the Agbada Formation. Gamma ray logs were primarily used to differentiate sandstone (clean, low gamma ray response) from shale intervals (high gamma ray response), while resistivity logs were used to confirm hydrocarbon saturation.

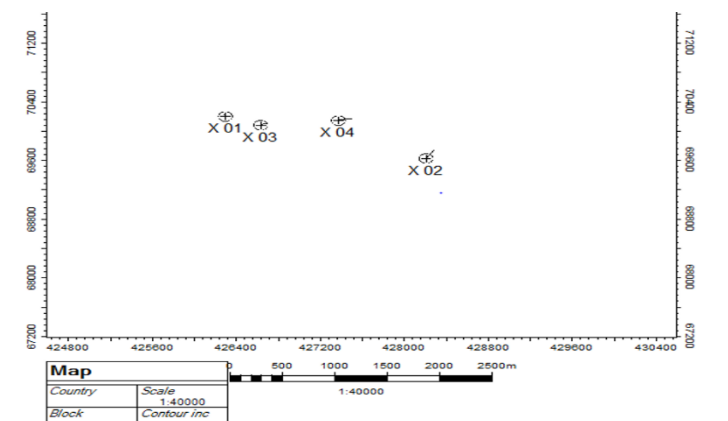


Fig. 3: Cross-sectional display showing the spatial arrangement of wells across Field X.

Reservoir units were defined based on:

- Gamma ray cut-off values for sand–shale discrimination
- Resistivity contrast indicating hydrocarbon presence
- Consistent log motif patterns across wells
- Net-to-gross reservoir thickness identification

Identified reservoir sands were then correlated across Wells X-01, X-02, X-03, and X-04 using stratigraphic marker horizons. Correlation panels were constructed to assess lateral continuity and identify stratigraphic breaks or offsets. This process enabled the identification of laterally continuous sand bodies (Sand A and Sand B) and the recognition of a structurally disrupted compartment associated with Well X-03.

Seismic Interpretation and Horizon Mapping

Time-migrated 3D seismic data were interpreted to establish the structural and stratigraphic framework of Field 'X'. The interpretation workflow involved:

Seismic–Well Tie

Synthetic seismograms were generated from sonic and density logs to tie well markers to seismic reflections. This calibration ensured accurate identification of reservoir top and base reflectors within the seismic volume (Fig. 4).

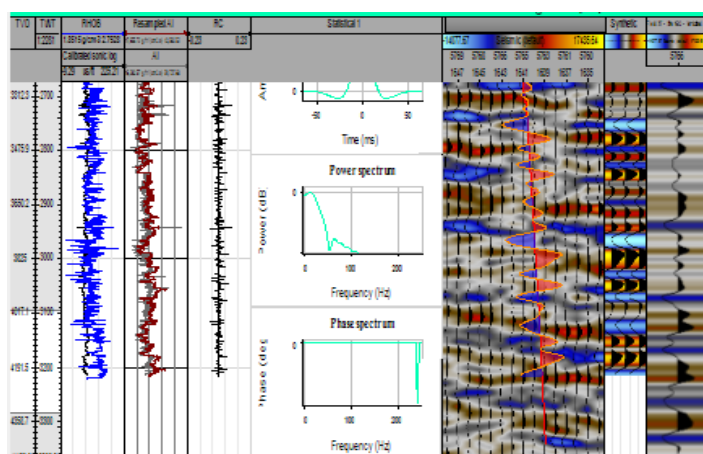


Fig. 4: Seismic to Well tie section.

i. Horizon Picking

Key stratigraphic horizons corresponding to reservoir tops and bases were manually and semi-automatically interpreted across inlines and crosslines. These horizons were tracked using seismic continuity, amplitude strength, and phase consistency.

ii. Fault Interpretation

Faults were interpreted using discontinuities in seismic reflections supported by:

- Reflection truncation and offsets
- Horizon terminations
- Coherence/variance discontinuities

Major and minor fault systems (F1–F4) were mapped in 3D space and structurally validated across multiple seismic sections.

Structural Modelling and Fault Analysis

A 3D structural framework was constructed by integrating interpreted horizons and fault surfaces. Fault geometries were modelled as listric growth faults typical of Niger Delta extensional systems.

Structural interpretation focused on:

- Fault throw and displacement distribution
- Hanging wall and footwall relationships
- Rollover anticline development
- Fault linkage and segmentation patterns

Fault compartments were delineated based on structural closure mapping and fault juxtaposition relationships between reservoir sands and sealing shales.

Fault seal potential was qualitatively assessed using:

- Lithological juxtaposition (sand–shale contacts)

- Fault continuity and segmentation style
- Seismic discontinuity strength along fault planes

This allowed classification of faults into sealing (e.g., F1) and potentially conductive (e.g., F2) structures.

Seismic Attribute Analysis for Reservoir Quality and Discontinuity

Seismic attributes were extracted from the interpreted seismic volume to enhance reservoir delineation and evaluate flow pathways.

Variance/Coherence Attribute

Variance (or coherence) attributes were used to identify structural discontinuities and fault zones. High variance values were interpreted as:

- Fault planes
- Fracture corridors
- Structural boundaries between compartments

This attribute was critical in refining fault interpretation and delineating reservoir compartment boundaries.

Amplitude Attribute

Root Mean Square (RMS) amplitude was computed over selected reservoir intervals to evaluate sandstone distribution and hydrocarbon potential. High-amplitude anomalies were interpreted as:

- Clean sandstone bodies
- Hydrocarbon-bearing reservoir zones
- Potential flow-conductive pathways

Amplitude continuity across fault blocks was used as a proxy for hydraulic communication, while abrupt amplitude terminations indicated possible sealing behaviour.

Reservoir Connectivity and Flow Pathway Analysis

An integrated reservoir connectivity model was developed by combining:

- Well log correlation frameworks
- Seismic horizon continuity
- Fault architecture
- Seismic attribute distributions

Connectivity assessment was performed qualitatively and semi-quantitatively by evaluating:

- Lateral continuity of sand bodies across wells
- Structural barriers imposed by faults
- Amplitude continuity across fault blocks
- Stratigraphic juxtaposition relationships

Reservoir compartments were defined based on hydraulic connectivity potential, distinguishing between:

- Connected compartments (continuous sand bodies across wells X-01, X-03, X-04)
- Isolated compartments (fault-bounded region around Well X-02)

Flow pathways were inferred as preferential directions of hydrocarbon migration along continuous high-amplitude sandstone trends and fault-assisted conduits where applicable.

Implications for Well Placement Optimisation

The final stage of the methodology involved integrating structural, stratigraphic, and connectivity interpretations to evaluate optimal well placement strategies.

Well placement considerations included:

- Positioning within laterally continuous sandstone bodies
- Avoidance or targeting of fault-bounded compartments depending on seal behaviour
- Identification of high-connectivity fairways from RMS amplitude trends
- Structural closure targeting within rollover anticlines and fault-assisted traps

This integrated approach provides a geological basis for identifying zones of maximum drainage efficiency and minimising risk of compartmentalised or isolated production zones.

Results

Reservoir Correlation and Lateral Continuity

Correlation of the reservoir intervals across the four wells established the presence of two major reservoir units (Fig. 5). Reservoir sands in wells X01, X03, and X04 display strong lateral continuity and comparable log signatures, indicating a laterally extensive and genetically related depositional system. The reservoirs are characterised by relatively thick sandstone packages with limited shale interbeds, suggesting favourable reservoir quality and continuity.

In contrast, well X02 exhibits a marked reduction in reservoir sand thickness accompanied by an increase in shale content. The reservoir intervals in X02 are not only deeper but also display poorer vertical and lateral continuity relative to the corresponding reservoirs in X01, X03, and X04.

These observations suggest that reservoir development deteriorates toward the X02 area. The progressive reduction in sand development and increase in shale content indicate a transition from a cleaner reservoir facies to a more heterolithic depositional environment. This facies variation likely contributes to the reduction in effective reservoir connectivity observed in X02.

Seismic Interpretation and Reservoir Delineation

The correlation between well markers and seismic reflections established a reliable framework for interpreting reservoir geometry across the field. Distinct seismic reflections corresponding to reservoir tops and bases were traced with confidence throughout the study area, enabling the delineation of reservoir boundaries and structural configurations.

The interpreted seismic responses show that laterally continuous, high-amplitude reflections are closely associated with the principal reservoir sands (Fig. 6a). These reflections persist across large portions of the field and suggest the presence of extensive sandstone bodies with relatively uniform depositional characteristics. In contrast, intervals characterised by weak, discontinuous, or chaotic reflections correspond to shale-dominated sections that exhibit limited reservoir potential.

The close agreement between the seismic interpretation and well observations strengthens confidence in the mapped reservoir framework. The interpreted horizon amplitudes reveal a structurally complex reservoir system in which faulting exerts significant influence on reservoir geometry, continuity, and hydrocarbon distribution (Fig. 6b).

The seismic interpretation further demonstrates that reservoir quality and continuity are not solely controlled by depositional processes but are strongly modified by post-depositional structural deformation. This relationship is particularly evident in areas where fault displacement affects reservoir thickness, continuity, and communication between adjacent compartments.

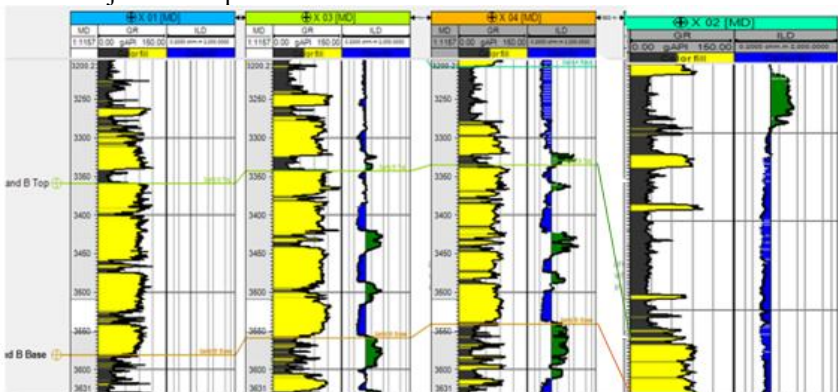


Fig. 5: Well logs/Reservoir correlation section of Field 'X'.

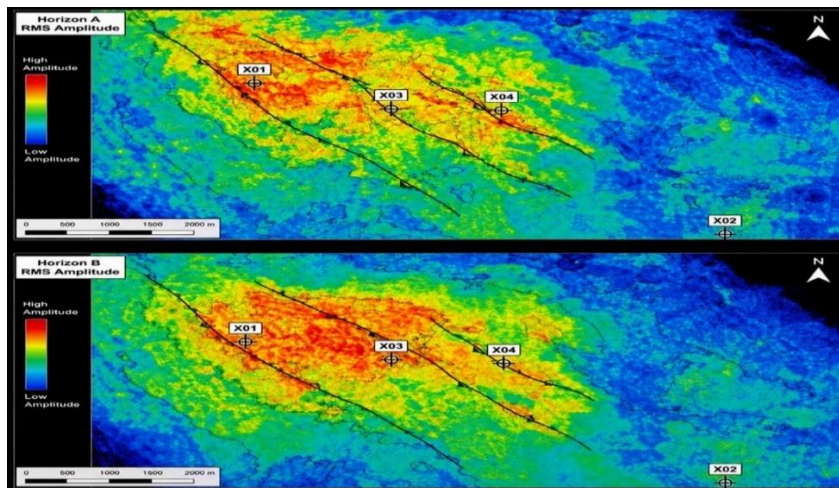


Fig. 6a: Amplitude Seismic Attribute in correspondence to reservoirs

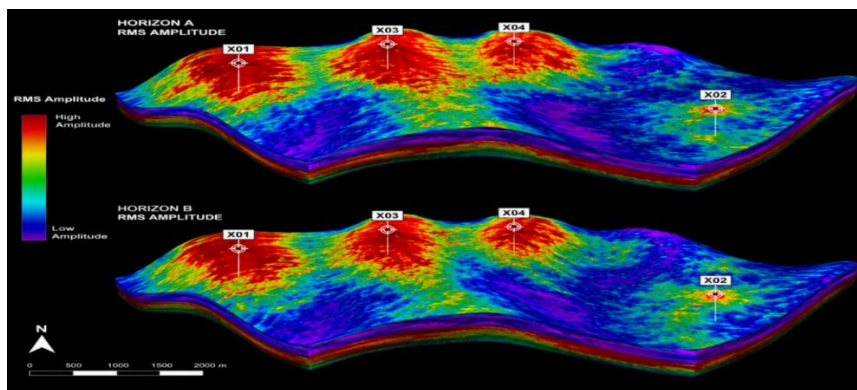


Fig. 6b: Amplitude Seismic Attribute reflecting the potential zones and structural setting

Structural Framework and Fault Architecture

Structural interpretation of the study area identified four faults (F1, F2, F3, and F4) that exert significant control on reservoir geometry and connectivity. Faults F1 and F2 constitute the major structural elements, while F3 and F4 are minor faults (Fig.7a and 7b). However, Fault F1 is the main dominant fault, exhibiting the greatest throw.

The structural model further indicates that wells X01, X03, and X04 are located within a structurally elevated block, while well X02 occupies a relatively deeper structural position (Figs. 8), which is a result of the major influence of Fault F1, as well as X02 is positioned in the downthrown block of Fault F1. Reservoirs encountered in X02 occur at greater depths compared to equivalent intervals in the other wells, suggesting significant displacement across F1.

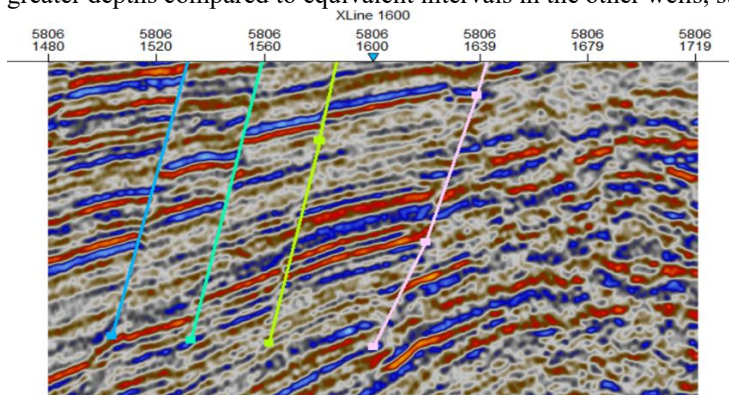


Fig. 7a: Seismic Interpreted Fault Section in Field 'X'.

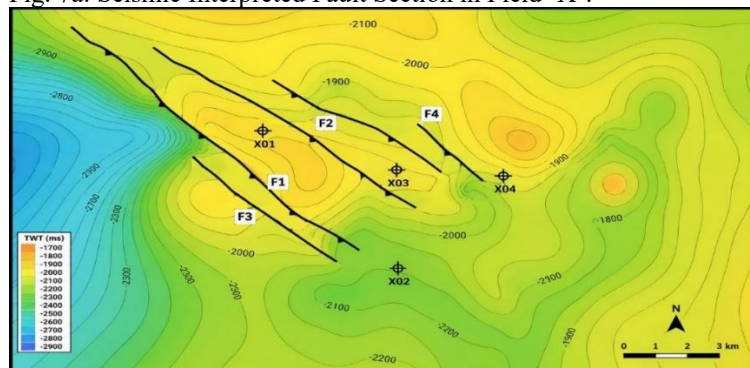


Fig. 7b: Structural map display of the major and minor faults

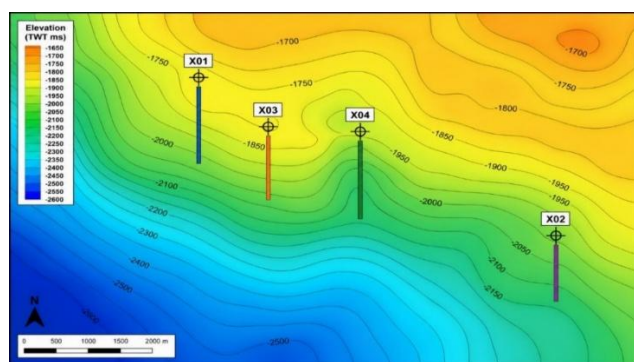


Fig. 8: Structural contour display of the well positions

The observed vertical separation of reservoir intervals across F1 indicates that the fault has accommodated sufficient throw to offset the reservoir units and establish distinct fault compartments. The sealing nature of F1 suggests that cross-fault fluid communication is restricted, thereby influencing reservoir connectivity and hydrocarbon distribution within the field.

Fault Juxtaposition and Reservoir Connectivity

The juxtaposition pattern observed along F1 provides a plausible explanation for the apparent loss of connectivity between X02 and the other wells. Although the reservoir intervals may have originally formed part of a continuous depositional system, subsequent fault displacement has resulted in compartmentalisation and hydraulic isolation of the X02 fault block (Fig. 9).

Analysis of fault juxtaposition relationships reveals that F2 juxtaposes reservoir sands against reservoir sands, thereby maintaining potential hydraulic communication across the reservoir. This interpretation is consistent with the observed continuity of reservoir units between wells X01, X03, and X04. The similarity in reservoir architecture across these wells suggests that F2 does not impede fluid flow within the reservoir system.

Though faults F3 and F4 exhibit a shale-on-sand juxtaposition, however not as pronounced as seen in F1, where the displacement is much greater, affecting the position of well X02, which is in the downthrown block of fault F1, thus preventing fluid communication between adjacent fault blocks. The connectivity analysis therefore suggests the existence of at least two distinct flow units within the field: a connected reservoir compartment comprising wells X01, X03, and X04, and a separate compartment associated with well X02.

Flow Pathway Analysis

The integrated evaluation of structural geometry, reservoir correlation, and fault seal behaviour reveals significant variations in flow pathways across the field (Fig. 9). The connected compartment containing wells X01, X03, and X04 exhibits favourable conditions for fluid migration and pressure communication due to the continuity of reservoir sands and the non-sealing nature of F2.

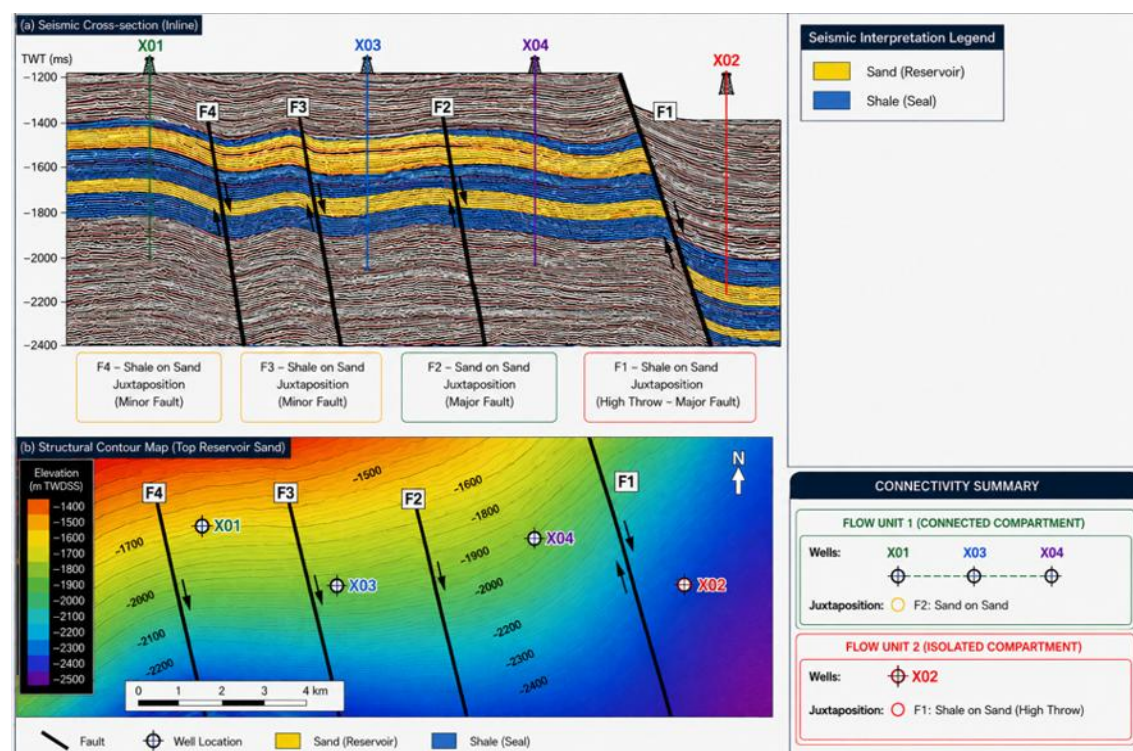


Fig. 9: Seismic display of Fault Juxtaposition across Field X

Within this compartment, hydrocarbons are expected to migrate efficiently through interconnected sandstone bodies, resulting in a larger effective drainage area and improved production performance. The continuity of reservoir properties across the compartment suggests the existence of laterally extensive flow pathways capable of supporting sustained hydrocarbon production.

In contrast, flow pathways associated with X02 appear restricted due to the combined effects of fault sealing and reservoir heterogeneity. The sealing behavior of F1 limits cross-fault communication, while the increased shale content within the reservoir interval further reduces permeability and reservoir connectivity.

Consequently, fluid flow within the X02 compartment is expected to be localized and less efficient compared to the structurally elevated compartment. These observations indicate that fault-controlled compartmentalization is the primary control on flow behavior within the field, while stratigraphic variability exerts a secondary influence on reservoir performance.

Implications for Hydrocarbon Recovery Enhancement

The comprehensive connectivity study showed large disparities in recovery potential among the studied reservoir compartments. The structurally high compartment with wells X01, X03 and X04 demonstrates the best combination of reservoir quality, lateral continuity and hydraulic communication. These characteristics indicate the existence of a bigger linked hydrocarbon volume and increased recovery potential. X02 is positioned deeper structurally, and the reservoir is less developed and isolated due to its relation with faults, suggesting a smaller and less productive reservoir compartment. If formed independently, this compartment may result in limited pressure support and lower recovery efficiency because of the reduced connectivity associated with this compartment.

The results demonstrate that recovery enhancement strategies should focus on maximising drainage within the connected X01–X03–X04 compartment while treating the X02 compartment as a separate development entity.

Well Placement Optimisation

The connectivity framework developed from this study provides important guidance for production well placement. The structurally elevated and laterally continuous reservoir compartment encompassing X01, X03, and X04 represents the optimum target for field development. Production wells located within this compartment are expected to access a

larger connected reservoir volume and benefit from improved pressure communication. The most favourable well locations are expected to occur within structurally high positions characterized by maximum reservoir thickness and superior sand development. Placement of horizontal wells within these intervals would maximise reservoir contact and enhance hydrocarbon recovery by improving sweep efficiency and drainage coverage. In contrast, production wells drilled within the X02 compartment would likely encounter reduced drainage volumes due to fault-induced isolation and poorer reservoir quality. Consequently, development of this compartment should be supported by additional volumetric and pressure analyses to determine its economic viability. The integration of fault seal analysis, reservoir correlation, and flow pathway characterisation demonstrates that reservoir connectivity is a critical factor controlling hydrocarbon recovery efficiency and optimal well placement within the study area.

Conclusion

This study incorporated structural interpretation, fault seal analysis, reservoir correlation and flow channel characterisation in an effort to analyse the reservoir connectivity and optimise the well location in a fractured hydrocarbon reservoir. We demonstrate that the relationship between fault architecture and depositional heterogeneity greatly controls reservoir performance and hydrocarbon recovery potential. Four faults (F1, F2, F3 and F4) were detected in the research region, of which F1 and F2 are the main structural controls. Fault seal study indicated that faults F1, F3, and F4 are sealing faults; however, fault F2 is non-sealing due to sand-on-sand juxtaposition. These diverse fault behaviours have a strong effect on reservoir connectivity and the patterns of fluid movement throughout the area.

Reservoir correlation revealed the presence of two main reservoir units in the examined wells. Wells X01, X03 and X04 are located in a structurally high fault block providing good reservoir continuity, favourable reservoir quality and good hydraulic communication. Conversely, well X02, located in a structurally lower compartment, is characterised by a deeper reservoir occurrence, less sand development, more shale composition, and less connectedness. The observed reservoir heterogeneity is understood to be a combined outcome of fault-induced compartmentalisation and depositional facies variation.

The results of the investigation showed that the main barrier to fluid communication was fault F1, which largely isolated well X02 from the associated reservoir system of wells X01, X03 and X04. Conversely, the non-sealing characteristic of F2 allows for lateral flow channels and pressure transmission within the structurally higher compartment. These results illustrate the existence of at least two discrete hydraulic compartments in the field with differing recovery potentials and development needs.

The RMS amplitude distribution shows large areas of high amplitude in structurally favourable areas of the field, particularly in the X01-X03-X04 compartment. These large amplitude anomalies correspond to the reservoir intervals reached by wells X01, X03 and X04 and are interpreted as laterally continuous sandstone bodies of good reservoir quality and hydrocarbon content [12]. The consistency of the amplitude responses of these wells implies good lateral continuity and supports the assumption that they are part of the same connected reservoir system with good internal communication. Conversely, the X02 well exhibits much weaker and more discontinuous RMS amplitude responses. The reduction of amplitude continuity suggests lower reservoir quality, more shale concentration and less sandstone development relative to the X01-X03-X04 area. The amplitude decrease observed toward X02 is consistent with a change into a more heterolithic depositional environment and supports the notion of diminished reservoir connection in this sector.

From a field development standpoint, the integrated connectivity study indicates that the structurally elevated and hydraulically connected compartment, encompassing wells X01, X03 and X04, is the most attractive target for hydrocarbon production. Improved reservoir continuity, improved flow paths and bigger connected reservoir volume suggest improved recovery efficiency and lower development risk. In contrast, the X02 compartment should be considered as a separate development unit because of its structural isolation and worse reservoir properties. To summarise, this study demonstrates the essential function of integrated reservoir connectivity and flow pathway analysis in lowering subsurface uncertainty and enhancing development decisions in structurally complex reservoirs. The results indicate that adding fault seal behaviour, reservoir design, and flow channel characterisation into well

placement techniques can substantially improve hydrocarbon recovery, enhance drainage efficiency, and optimise field development performance.

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