Integration of Structural Seismic Interpretation, Stratigraphic and Petrophysical analysis for the Hydrocarbon play assessment of ‘X’ - field within the Coastal Swamp Depobelt of Niger Delta

By

Eze, U. Stanley*, Orji, M. Omafume**, Nnorom .S. Lotanna***

Abstract
This study presents the results of integrating structural time-depth maps, fault delineating seismic attributes such as root mean square (RMS) and variance, seismic facies interpretation and petrophysical model distribution to quantitatively define reservoir units across four wells to enable hydrocarbon play assessment in the X-field in the Niger Delta Basin. Four reservoir windows (A, B, C and D) were delineated from four wells (W-026, 032, 042 and 048). The top and base of each reservoir window were delineated from the four wells using their gamma ray and resistivity log responses. Structural interpretation for inline 4997 revealed four horizons (A, B, C and D) and fourteen faults labelled (F5, F6, F11, F12, F13, F14, F15, F18, F20, F28, F29, F30, F31, and F32). Ten of the faults are synthetic and dip basinward, while three are antithetic and dip landwards. Faults F5, F6, F12 and F13 cut across the entire horizons (major faults) and created an alternation of basinward and landward dipping normal faults which formed a horst and graben structure. These structures created mini depocentres which controlled depositional patterns in the field, and suggests that they are responsible for trapping of hydrocarbons in the field. RMS map developed for horizons ‘C’ and ‘D’ revealed high amplitude anomalies (bright spot) while variance attribute for both horizons revealed a channel-fill sand depression trending NE – SW and terminated at fault F12. Structural interpretation showed a highly faulted reservoir system which depicts the tectonic character of the Niger Delta. Log motifs using gamma ray log signatures at the top and base of the four reservoirs showed a combination of fining and coarsening upward cycles. For reservoir ‘A’, the log shape pattern indicates deposition in a fluvial / tidal, channel, delta front environment, while for reservoirs ‘B’, ‘C’ and ‘D’ the pattern indicates deposition in alternating low and high energy regimes suggestive of marshy or swampy lagoons and delta front environment. Results of petrophysical evaluation for reservoirs ‘C’ and ‘D’ across the four wells were analyzed. For reservoir ‘C’, porosity values of 30.85%, 29.06%, 26.54% and 27.39% were obtained for wells W-048, 042, 026 and 032 respectively with an average of 28.46%, while for reservoir ‘D’ porosity values of 28.81%, 33.55%, 25.88% and 27.75% were obtained for the wells with an average of 28.99%. These porosity values were rated very good to excellent and validate the already known porosity range of 28-32% within the Aghada Formation. Permeability values of the order (K > 1000 mD) were obtained for both reservoirs across the four wells and is rated excellent. Hydrocarbon saturation (S\text{oc}) across the four wells averages at 68.34% and 69.27% for reservoirs ‘C’ and ‘D’. The high average values of hydrocarbon saturation indicates that the reservoirs will produce water-free hydrocarbon at irreducible water saturation and affirms that they are highly prospective.

Keywords: Structural interpretation, Faults, Horst and graben, Seismostratigraphy, Well log, Seismic Attributes, Petrophysical parameters.

Introduction
The fundamental essence of integrating 3D seismic data and well logs is to obtain a high level of precision in interpreting subsurface structures suitable for hydrocarbon accumulation in a given region¹.

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Most interpreters have realised that integration of seismic data with other data types is necessary for proper interpretation of 3D seismic data. Therefore, integrating seismic and well data gives better results than either in isolation because both the areal coverage of seismic data and the accuracy of the well data can be tied together to give a direct correlation between seismic facies type and lithology. This forms the basis of integrating both data.

The seismic reflection method, ever since its discovery in the late 1920s, still remains one of the most effective tools in the search for hydrocarbons. Reflections are due to contrast in acoustic impedance in the subsurface caused by differences in physical properties of rocks which can be density and compressional wave velocity and can be explained in terms of lithology, porosity and porefill as cited by Eze et al.,. The principal objective of a 3D seismic survey is to delineate structures, as well as acquire exact definition of subsurface stratigraphy and rock physical properties which aid in mapping of geological structures suitable for hydrocarbon accumulation and keep it from migrating either vertically or laterally. However, many structures that provide excellent traps do not contain oil and gas in economic quantities. And due to the high cost of drilling, effort is made to derive from the seismic data as much information as possible about the nature of the rocks and subsurface structures in an effort to form an opinion about the probability of encountering hydrocarbon in economic quantities in the structures delineated from the seismic records.

The pursuit of an ideal approach for hydrocarbon play assessment has been a task that many oil and gas organizations are engrossed with. Observation has shown that only one-third of oil in place has been recovered through the conventional method of production as cited by Amarachukwu and Temitope. Information crucial to reservoir characterisation includes determination of reservoir limits, structural disposition of the reservoir, volume and reservoir properties such as porosity, permeability, net pay thickness, and other parameters. Therefore, integrating seismic and well data gives better results than either in isolation because both the areal coverage of seismic data and the accuracy of the well data can be tied together to give a direct correlation between seismic facies type and lithology. This forms the basis of integrating both data.

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and lithologic heterogeneity\textsuperscript{12}. Several authors such as\textsuperscript{13, 14, 15, 16} have integrated well log and seismic data to characterise reservoirs in various onshore and offshore Niger Delta fields. They observed complex patterns of subsurface structures bounded by growth faults, faulted rollover anticlines and collapsed crest structures. They also discovered that a system of antithetic and synthetic normal faulting compartmentalized the reservoirs into several blocks of variable sizes.

The aim of this study is to demonstrate the effectiveness of integrating results from structural seismic interpretation, attribute analysis, seismostratigraphic interpretation and well log to quantitatively define the hydrocarbon reservoir in terms of its structural disposition, environment of deposition, facies distribution and petrophysical parameters with the intent of resolving the ambiguities associated with hydrocarbon play assessment within the Niger Delta Basin.

**Geologic Setting**

The study area falls within OML 23 and lies between latitudes $4^\circ 37' 36''$N and $4^\circ 40' 00''$N, and longitudes $6^\circ 35'E$ and $6^\circ 40'E$ within the coastal swamp depobelt of the Niger Delta. OML 23 lies within the Kalabari community ($4^\circ 40' 41.85''$N, $6^\circ 40' 57.02''$E) located in Akuku Toru Local Government Area (AKULGA). It is operated by Shell Petroleum Development Company (SPDC) of Nigeria. Operations started in 1957, following the discovery of oil in commercial quantities at Oloibiri in Bayelsa State in 1956. According to records, the field was near Oloibiri where oil was first discovered. The area is surrounded by a number of tidal estuarine water bodies, namely Sombreiro and Saint Batholomeau Rivers.

\textsuperscript{14}Ayolabi, E.A., and Adigun, A. O. (2013). The Use of Seismic Attributes to Enhance Structural Interpretation of Z-Field, Onshore Niger Delta. Published by Canadian Center of Science and Education; Earth Science Research; Vol. 2, No. 2.
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Figure 1: Base map of study area showing Ugwu’s field and the various oil well locations (Ugwu-026, 030, 032, 042, and 048).

The Niger Delta basin is a prolific hydrocarbon province that evolved in early Cenozoic times\(^\text{17}\). The delta is known to have prograded over the subsidizing continental-oceanic lithospheric transition zone, and during the Oligocene spread into oceanic crust of the Gulf of Guinea\(^\text{18, 19}\). The Cenozoic Niger Delta has been noted as one of the largest delta systems in the world with an areal surface extent of about about 300,000 km\(^2\)\(^\text{20}\), with a sediment thickness of over 12 km in the basin depocentre\(^\text{21}\). The early Niger Delta is interpreted as being a river-dominated delta, however the post-Oligocene delta is a typical wave-dominated delta with well-developed shoreface sands, beach ridges, tidal channels, mangrove and freshwater swamps Orife and Avbovbo\(^\text{22, 23, 24}\).

Obaje\(^\text{25}\), opined that the Niger Delta is one of the world’s largest deltas and shows an overall upward transition from marine shales (Akata Formation) through a sand-shale paralic interval (Agbada Formation) to continental sands of the Benin Formation Akpoyovbike\(^\text{26}\), Michele et al.\(^\text{27}\), as cited by Obaje\(^\text{28}\). Depending on relative sea level changes, local subsidence and

\(^{17}\)Doust, H; Omatosla, E (1990). Niger Delta, in Edwards, JD; Santogrossi, PA eds; Divergent/passive Margin basins; AAPG Memoir 45; P. 239–248.


\(^{22}\)Op. Cit.


\(^{25}\)Ibib.

\(^{26}\)Op. Cit.


\(^{28}\)Op. Cit.
sediment supply, the delta experiences episodes of regressions and transgressions\textsuperscript{29, 30}. The stratigraphic arrangement of the Niger Delta comprises of three wide lithostratigraphic units Akpoyovbike\textsuperscript{31} namely; a continental shallow massive sand sequence – the Benin Formation, a coastal marine sequence of alternating sands and shales – the Agbada Formation and a basal marine shale unit-the Akata Formation. The Akata Formation consists of clays and shales with minor sand alternations Obaje\textsuperscript{32}. The sediments were deposited in prodelta environments, with sand percentage collectively less than 30% Alao et al.,\textsuperscript{33} The Agbada Formation comprises of successions of sand and shales representing sediments of the transitional environment comprising the lower delta plain (mangrove swamps, floodplain and marsh) and the coastal barrier and fluviomarine realms. According to Obaje\textsuperscript{34}, the sand percentage within the Agbada Formation varies from 30 to 70%, which results from the large number of depositional offlap cycles. The entire cycle consists of thin fossiliferous transgressive marine sand, followed by an offlap sequence which begins with marine shale and continues with laminated fluviomarine sediments, followed by barriers and/or fluviatile sediments terminated by another transgression cycle\textsuperscript{35, 36} as cited by Alao et al.,\textsuperscript{37} The Benin Formation consists of high sand percentage (70–100%) and forms the top layer of the Niger Delta depositional sequence Alao et al.,\textsuperscript{38}. According to Obaje\textsuperscript{39}, the massive sands were deposited in continental environment comprising the fluvial realms (braided and meandering systems) of the upper delta plain Alao et al.,\textsuperscript{40}, Nancy et al.,\textsuperscript{41}.

Doust and Omatsola\textsuperscript{42}, as cited by Nancy et al.,\textsuperscript{43} recognised six depobelts in the Niger Delta, which are distinguished primarily by their age, these are; Northern Delta (Late Eocene-Early Miocene), Greater Ughelli (Oligocene-Early Miocene), Central Swamp I (Early-Middle Miocene), Central Swamp II (Middle Miocene), Coastal Swamp I and II (Middle Miocene) and offshore megastructures (Late Miocene). The study area falls within ‘Coastal Swamp I’ depobelts. Growth faulting dominates the structural style of the Niger Delta.


\textsuperscript{30}Alao, PA; Ata, AI; Nwoke, CE; Chuo, YJ; Tzanis, A (2013). Subsurface and Petrophysical studies of Shaly-sand Reservoir targets in Apete field, Niger Delta, Hind. Geophy. 10: P. 1155.

\textsuperscript{31}Op. Cit.

\textsuperscript{32}Op. Cit.

\textsuperscript{33}Op. Cit.

\textsuperscript{34}Op. Cit.


\textsuperscript{37}Op. Cit.

\textsuperscript{38}Op. Cit.

\textsuperscript{39}Op. Cit.

\textsuperscript{40}Op. Cit.


\textsuperscript{42}Op. Cit.

\textsuperscript{43}Op. Cit.
This structural style has been interpreted to be triggered by the movement of deep-seated, over pressured ductile marine shale and aided by slope instability\textsuperscript{44}. Hanging-wall rollover anticlines are common in the Niger Delta. They were produced from listric-fault geometry and differential loading of deltaic sediments above the ductile shale. As sediment loading in the depobelt ceased, the depocenters shifted seaward and loaded the displaced thick mobile shale\textsuperscript{45}. Hydrocarbon occurrence was originally ascribed to timing of trap formation relative to petroleum migration (earlier landward structures trapped earlier migrating oil). Petroleum occurs within the Agbada Formation of the Niger Delta Basin.

**Materials and Methods**

**Materials**

In this study, a suite of composite logs which contain Gamma ray (GR), Resistivity, Spontaneous Potential (SP), Sonic, density and Neutron logs from four wells was used. The respective depths of the wells are 11592.02ft for ‘Well-026’; 10718.52ft for ‘Well-032’; 13310.53ft for ‘Well-042’, which is the deepest and 11488.02ft for ‘Well-048’. Also a 3D seismic data volume (in SEG-Y format) having a total of 1106 inlines and 791 cross lines was used for this study.

**Picking of reservoir intervals, Well correction and Well-to-seismic correlation**

The initial procedure in this study was to pick the reservoir intervals from well logs. The reservoir intervals were picked using a combination of gamma ray and resistivity log signatures across the four wells. Lithologic units were delineated in vertical succession by distinct surfaces which represent changes in lithologic character. Four reservoir intervals (marked A, B, C and D) were picked. Well correlation, which is the determination of the continuity and equivalence of lithologic units, particularly reservoir sands, was carried out across the wells in the field. This includes the recognition of log pattern (sand and shale signatures) on well logs and matching these patterns from one well to the other. This provided the basis for correlation to determine the lateral extent of the reservoir sand of interest and determination of the resistivity of the interpreted formations from the resistivity log. Accurate correlation of well logs is very important for reliable geologic interpretations\textsuperscript{46} as it provides information such as lithology, reservoir thickness, and tops and bases of units of interest\textsuperscript{47}

Well-to-seismic tie, which seeks to import well information into the seismic, was carried out using shot data from well-026, which was further correlated with other wells. A plot of depth (ft) against two way time (TWT in ms) for well-026 in Figure 2, gave a linear regression function of the type \( y = mx + c \), where \( m \) is the slope which is equal to 0.25667 and an intercept of -8.50722 as shown in Figure 2.


The slope of the depth (ft) – time (sec) curve is equivalent to velocity (v) given as:

\[ v = \frac{d}{t}, \quad t = \frac{d}{v} \]  

(1)

\[ TWT = 2t = \frac{2d}{v}, \text{Slope (m) from figure 2} = \frac{2t}{d} = \frac{m}{2} = \frac{t}{d} = \frac{1}{v} \]  

(2)

Therefore; \( \frac{m}{2} = \frac{1}{v} \); and \( v = \frac{2}{m} \)  

(3)

Where \( d \) is measured depth in ft, \( t \) is sonic time, \( TWT \) is two way time in ms, \( m \) is the slope of the T-Z plot (\( m = 0.25667 \)) and \( v \) is the interval velocity in ft/s. Using eqn (3), a velocity of 7,792.11 ft/s was obtained from the time-depth curve and used for well to seismic tie. The acoustic velocities from sonic log were multiplied with density log from well-026 to compute new acoustic impedance (AI) log. This impedance log was converted to reflectivity, which was then converted from depth to time using an appropriate wavelet to produce a synthetic seismogram for well-026.

\[
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Fault / Horizon Mapping, picking of major faults and creation of surface, depth and attribute maps

Fault mapping was done by picking fault segments on vertical seismic sections and correlating them across from line to line. Faults were identified on inline (dip lines) 4997 of the seismic section by selecting points where the seismic events are truncated or at points of discontinuity. Following this, four horizons (A, B, C and D) were picked at two way time’s -2227.76ms, -2475.09ms, -2516.98ms and -2697.25ms. Horizon ‘A’ was picked at a top depth of 8750.43 ft in well-026 and tied to a TWT of -2227.76 ms which concides with the trough on the synthetic seismic. Horizon ‘B’ was picked at a top depth of 10024.52 ft in well-026 and tied to a TWT of -2475.09 ms which concides with the peak on the synthetic seismic. Horizon ‘C’ was picked at a top depth of 10450.47 ft in well-026 and tied to a TWT of -2516.98 ms which concides with the trough on the synthetic seismic, while horizon ‘D’, picked at a top depth of 11075.27 ft in well-026.

Figure 2: Time-depth plot of checkshot data for well-026.

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ft in well-026, was tied to a TWT of -2697.25 ms and coincides with the trough on the synthetic seismic. Horizons ‘A’, ‘B’, ‘C’, had mistie as the peak from the synthetic seismic generated at this horizons do not exactly match the peak in the real seismic. This could be attributed to heterogeneity in the subsurface caused by tectonic uplift or ‘sink holes’. The variation in polarity (peak and trough) could be as a result of faulting or velocity distortion during processing. This mistie in polarity was rectified using the normalisation button on petrel software. This toggled off ‘SEG-Y’ as default, and the respective tops and bases of horizons ‘A’, ‘B’, ‘C’ and ‘D’ were then picked on inline (4997) of the seismic section for fault/horizon mapping.

Fault visualization on 3D seismic volumes is enhanced by computing edge detection attributes such as root mean square (RMS), variance and coherence\(^{49}\). Therefore in this study, RMS and variance attribute maps were computed for the horizons to visualise faults more clearly.

**Seismostratigraphic analysis and petrophysical evaluation**

This step was carried out to correlate reflection attributes to the stratigraphic characteristics of identified facies, thereby providing a correlation framework between seismic and well data. These reflection characteristics vary laterally with facies, and these lateral changes in physical properties of subsurface rocks allow the acoustic impedance contrast necessary to generate the seismic reflections\(^{50}\). Several studies have shown a direct correlation between seismic facies type and lithology Emery and Myers\(^{51}\).

<table>
<thead>
<tr>
<th>Seismic Facies</th>
<th>Lithofacies</th>
<th>Gamma Ray Response</th>
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<tbody>
<tr>
<td>A</td>
<td>Inboard: limestone with interbedded clastics, Outboard: claystone with minor limestone interbeds</td>
<td>Inboard: funnel-shaped, Outboard: Ratty to crescent-shaped</td>
</tr>
<tr>
<td>B</td>
<td>Inboard: sandstone interbedded with siltstone, claystone (with trace coal and limestone stringers around Dockan-1 area)</td>
<td>Ratty-bell shaped-blocky</td>
</tr>
</tbody>
</table>

Table 1: Correlation between seismic facies and lithofacies from previous studies (After Emery and Myers\(^{52}\))

In this study, three reflection attributes were employed to discriminate between different seismic facies: (a) Reflection geometry (b) Reflector continuity and (c) amplitude. Attempt was made to calibrate the seismic facies type’s identified and well data (gamma ray/GR log curves only). After establishing the key horizons, seismic facies in the units between horizons were identified.

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\(^{52}\)Ibib.
Petrophysical evaluation provides an understanding of the rock and fluid properties within the reservoir rocks. These properties form the basis for detailed reservoir quality evaluation. Five petrophysical parameters which include Volume of shale ($V_{shale}$), porosity ($\Phi$), water saturation ($S_w$), hydrocarbon saturation ($S_h$) and permeability index ($k$) were computed for the tops and bases of reservoirs C and D.

Volume of Shale was obtained for the four wells using Larionov tertiary rock method given as:

$$V_{shale} = 0.083 \left(2^{3.7 \times IGR} - 1\right)$$  \hspace{1cm} (4)

$$ GR_{\text{index}} = \frac{GR_{\log} - GR_{\text{min}}}{GR_{\text{max}} - GR_{\text{min}}} $$  \hspace{1cm} (5)

Where; $GR_{\text{index}}$ = gamma ray index, $GR_{\log}$ = GR reading of formation, $GR_{\text{min}}$ = minimum GR for (clean sand), $GR_{\text{max}}$ = maximum GR for (shale).

Porosity was calculated for the four wells from bulk density log using:

$$ \Phi(Den) = \frac{\rho_{ma} - \rho_f}{\rho_{ma} - \rho_{fl}} $$  \hspace{1cm} (6)

Where; $\Phi(Den)$ = density derived Porosity, $\rho_{ma}$ = Matrix density usually 2.65 g/cm$^3$ for sandstones, $\rho_f$ = bulk density of formation, $\rho_{fl}$ = Fluid density usually 0.9.

By Using the log reading obtained from the given logs for the four wells, the porosity of each reservoir interval were determined and an average value obtained.

Water saturation ($S_w$) was determined using the Archie model (for clean sand formations) given as:

$$ S_w = \left(\frac{aR_w}{\phi^{m}R_t}\right)^{1/n} $$  \hspace{1cm} (7)

Where; $S_w$ = water saturation of un-invaded zone, $R_w$ = Formation water resistivity, $R_t$ = formation Resistivity (Un-invaded zone), $\phi$ = Porosity, $a$ = Tortosity factor $m$ = Cementation exponent, $n$ = Saturation exponent

Hydrocarbon saturation ($S_h$) was computed using:

$$ S_h = (1-S_w) $$  \hspace{1cm} (8)

Permeability index ($k$) in millidarcy was calculated using Owolabi and Obot model given as:

$$ K = 307 + 26,552\phi^2 - 34540(\phi \times S_{wi})^2 \text{ for oil ~ sand} $$  \hspace{1cm} (9)

Where; $\phi$ = porosity, $S_{wi}$ = irreducible water saturation given as:

$$ S_{wi} = (F/2000)^{1/2} $$  \hspace{1cm} (10)

F is the formation factor (F) given as $F = a / \phi^m$  \hspace{1cm} (11)

Where; $a$ = tortuosity factor = 0.62, $m$= cementation factor = 2.15. The average values of the petrophysical parameters within the reservoir intervals for the four wells were obtained.

Porosity and permeability values obtained were rated based on Rider\textsuperscript{57} qualitative evaluation criteria.

Table 2: Qualitative evaluation of porosity and permeability (After Rider\textsuperscript{58})

<table>
<thead>
<tr>
<th>Percentage Porosity (%)</th>
<th>Qualitative Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-5</td>
<td>Negligible</td>
</tr>
<tr>
<td>5-10</td>
<td>Poor</td>
</tr>
<tr>
<td>11-15</td>
<td>Fair</td>
</tr>
<tr>
<td>15-20</td>
<td>Good</td>
</tr>
<tr>
<td>20-30</td>
<td>Very Good</td>
</tr>
<tr>
<td>&gt;30</td>
<td>Excellent</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Average Permeability Value (md)</th>
<th>Qualitative Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt;10.5</td>
<td>Poor</td>
</tr>
<tr>
<td>11-15</td>
<td>Fair</td>
</tr>
<tr>
<td>15-50</td>
<td>Moderate</td>
</tr>
<tr>
<td>50-250</td>
<td>Good</td>
</tr>
<tr>
<td>250-1000</td>
<td>Very Good</td>
</tr>
<tr>
<td>&gt;1000</td>
<td>Excellent</td>
</tr>
</tbody>
</table>

Results and Discussion

**Reservoir Window Delineation; Well to Seismic Correlation and Structural interpretation of Inline 4997.**

Figure 3a shows the reservoir intervals (A, B, C and D) at the top and base delineated for the four wells, which were correlated to determine the lateral extent of the reservoir sand across the wells in the field. It was also observed that structural dip increased downward and decreased upward (extensive faulting was observed within the Agbada Formation). Figure 4 shows the result of well-to-seismic correlation using a synthetic seismogram, with well-026 as reference well. Figure 5a is the uninterpreted seismic section for inline 4997, while Figure 5b is the interpreted seismic section for inline 4997 showing reservoir horizons A, B, C and D. Fourteen (14) faults were identified on inline 4997 and labelled as (F5, F6, F11, F12, F13, F14, F15, F18, F20, F28, F29, F30, F31, and F32) in Figure 5b. Table 3 shows the horizons and faults which each horizon cuts at their respective two-way-time’s on inline 4997. In Figure 5b, it was observed that faults F6, F12, F13 and F15 cut across the four horizons and are considered as major faults across the studied horizons.

Ten (10) faults in Figure 5b (F5, F11, F12, F13, F14, F20, F28, F29, F31 and F32) were identified as synthetic faults as they dip basinward while three (3) antithetic faults (F6, F15 and F18) were identified in Figure 5b dipping landward. Fault ‘F12’ (a major fault) in Figure 5b created a fault plane which controls the two segments of the block labelled ‘X’ and ‘Y’ in Figure 5b. ‘X’ is the upthrown block while ‘Y’ is the downthrown block trending NE to SW. Hydrocarbon accumulation in the field is likely to be towards sections of the upthrown block, as the shale diapirs and fault zones below it act as a seal. Also, Faults (F6 and F18) in Figure 5b created a normal fault pattern where the hanging wall is down relative to the footwall. Faults F5, F6, F12 and F13 which cut across the entire horizons in Figure 5b (major faults) created an alternation of basinward and landward dipping normal faults which formed a horst and graben structure. These structures (horst and graben) created mini-deposcentres and are key factors controlling depositional patterns in the field. Therefore, faults F5, F6, F12, and F13 which cut

\textsuperscript{57}Rider, (1996), The geological interpretation of well logs, 2\textsuperscript{nd} edition, Gulf Publishing Company Houston, P. 230.

\textsuperscript{58}Ibib.
across the entire four reservoirs are invaluably responsible for trapping of hydrocarbons in the field.

Figure 3a: Well correlation for the four wells, showing the top and base of the reservoir intervals (A, B, C and D) delineated for each well.

Most of the interpreted faults terminated at the top of shale diapirs at the distal part of the seismic section, and this provides the necessary structure and geology suitable for trapping in the area. Figure 6 is a cross-section of the four horizons A, B, C and D showing the various structures in the field. Structural interpretation revealed a highly faulted reservoir system, which agrees with the work of Merki.

Integration of Structural Seismic Interpretation, Stratigraphic and Petrophysical analysis for the Hydrocarbon play assessment of ‘X’ - field within the Coastal Swamp Depobelt of Niger Delta

Figure 3b: Base map showing the four wells and how each well is linked to the other.

Figure 4: Seismic-to-well tie for well-026.
Figure 5a: Uninterpreted inline 4997 Seismic section

Figure 5b: Interpreted inline 4997 Seismic section
Table 3: INLINE 4997; Identified two way time within the mapped horizons

<table>
<thead>
<tr>
<th>S/n</th>
<th>Faults</th>
<th>TWT(HA)ms</th>
<th>TWT(HB)ms</th>
<th>TWT(HC)ms</th>
<th>TWT(HD)ms</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>F13</td>
<td>2375</td>
<td>2625</td>
<td>2650</td>
<td>2775</td>
</tr>
<tr>
<td>2</td>
<td>F28</td>
<td>2238</td>
<td>2500</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>3</td>
<td>F20</td>
<td>2250</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>4</td>
<td>F18</td>
<td>2250</td>
<td>2500</td>
<td>2512</td>
<td>-</td>
</tr>
<tr>
<td>5</td>
<td>F6</td>
<td>2262</td>
<td>2512</td>
<td>2525</td>
<td>2725</td>
</tr>
<tr>
<td>6</td>
<td>F12</td>
<td>2274</td>
<td>2512</td>
<td>2519</td>
<td>2775</td>
</tr>
<tr>
<td>7</td>
<td>F31</td>
<td>2375</td>
<td>2625</td>
<td>2537</td>
<td>-</td>
</tr>
<tr>
<td>8</td>
<td>F32</td>
<td>2378</td>
<td>2628</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>9</td>
<td>F5</td>
<td>2387</td>
<td>2762</td>
<td>2562</td>
<td>2875</td>
</tr>
<tr>
<td>10</td>
<td>F11</td>
<td>2500</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>11</td>
<td>F15</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>12</td>
<td>F29</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>13</td>
<td>F30</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>14</td>
<td>F14</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

TWT = Two way time (ms); {H (A–D)} denotes Horizons ‘A’ to ‘D’; ‘-‘ denote no horizon cutting faults.

Figure 6: Cross-section of the four horizons trending in the NW-SE direction

**Depth Maps; Root mean square (RMS) and Variance attribute maps for horizons ‘C’ and ‘D’.*

The shallowest and deepest parts of the surface of horizons ‘C’ and ‘D’ were estimated to occur at two way time’s of 2500 ms and 2600 ms for horizon ‘C’ and two way time’s of 2700 ms and 2800 ms for horizon ‘D’ on their time contour maps (Figures 7a and 8a).
Figure 7: (7a) Time map of horizon ‘C’ view on (E-W direction); (7b) Depth map of horizon ‘C’ view on (E-W direction); (7c) RMS map of horizon ‘C’ view on (E-W direction); (7d) Variance map of horizon ‘C’ view on (E-W direction).

Figure 8: (8a) Time map of horizon ‘D’ view on (E-W direction); (8b) Depth map of horizon ‘D’ view on (E-W direction); (8c) RMS map of horizon ‘D’ view on (E-W direction); (8d) Variance map of Horizon ‘D’ view on (E-W direction).

For horizon ‘C’, these times correspond to depths of about 9400 ft and 9900 ft respectively on the depth contour map for horizon ‘C’ (Figure 7b). For horizon ‘D’, it corresponded to depths of 10000 ft and 10500 ft on the depth contour map for horizon ‘D’ (Figure 8b). The depth maps
Integration of Structural Seismic Interpretation, Stratigraphic and Petrophysical analysis for the Hydrocarbon play assessment of ‘X’ - field within the Coastal Swamp Depobelt of Niger Delta

for horizons ‘C’ and ‘D’ (Figures 7b and 8b) showed the structural high closures 1 and 2. Root mean square (RMS) maps developed for horizons ‘C’ and ‘D’ (Figures 7c and 8c), revealed that the closures observed on the depth maps for both horizons, showed high amplitude anomalies (bright spots) on their RMS maps. This is diagnostic of the presence of hydrocarbons at these reservoir horizons. Channel-like structures and faults are more visible on variance maps (fault delineating seismic attribute) shown in Figures 7d and 8d. From the legend on the variance maps, it was observed that change in acoustic impedance (which is a function of lithology) increases upwards. Fault polygons were superimposed on variance map in Figure 9. This revealed a channel fill sand depression trending NE-SW and terminated at fault F12 (Figure 9). This depression could serve as a channel through which continentally derived detrital sediments would be accommodated in the region of the anticlinal structure on the downthrown block of fault F12. In Figure 7d, channel-fill deposits trending NE-SW were also observed. This trend exposes dipping of the channel fill at both flanks by creating extensive faulting.

Figure 9: Fault polygon superimposed on variance attribute map and viewed in NE-SW direction.

Seismostratigraphic Interpretation of Inline 4997 and Log Motifs using Gamma-ray log
The result of seismostratigraphic interpretation of inline 4997 is shown in Figures 10a & b. Three seismic facies characteristic of different depositional origin were identified within the 3D seismic profile which are; the upper ‘unit A’ characterised by sub-parallel and low amplitude discontinuous facies which is characteristic of delta plain deposits\(^{62}\). The central ‘unit B’ underlain by highly faulted parallel and low to high amplitude discontinuous middle unit, which is characteristic of prograding delta front to shoreface deposits, and the lower ‘units C’ dominated by chaotic facies which is characteristic of offshore mud deposits and deep water environments Emudianughe et al.,\(^{63}\). It was observed that most of the major faults mapped in the


\(^{63}\)Ibib.
field terminated on ‘unit C’ (Figure 10a & b). Each seismic facies was assigned a unique two-way time and was mapped on the seismic grid.

Figure 10a: Inline 4997: Un-interpreted Seismic Facies.

Figure 10b: Inline 4997: Interpreted Seismic Facies: A = sub parallel to low amplitude discontinuous facies, B = parallel, low to high amplitude discontinuous facies, and C = low amplitude discontinuous to chaotic facies.
Integration of Structural Seismic Interpretation, Stratigraphic and Petrophysical analysis for the Hydrocarbon play assessment of ‘X’ - field within the Coastal Swamp Depobelt of Niger Delta

Attempts were made to deduce the environment of deposition of facies within the identified reservoirs from their gamma-ray log shape. Log motifs of the four reservoirs show a combination of fining and coarsening upward cycles including blocky and serrated cylindrical signatures forming a funnel shape geometry across various depositional sub-environments such as shorefaces, mouth bars, tidal channels and fluvial channels among others.

Generally, Gamma ray log signatures show a combination of serrated funnel shape and relatively serrated-blocky shape, indicating coarsening stacking patterns which indicate deposition in deltaic environment complex consisting of tidal flats, fluvial channels and/or deltaic distributaries\(^\text{64}\). When the reservoir intervals were flattened on their respective tops and bases, various geometrical architectures were approximately inferred. Table 4 shows the seismic characterisation and depositional facies interpretation of inline 4997.

**Figure 11a:** Reservoir ‘A’ geometry across the wells. Reservoir ‘A’ thins out at the centre cutting across well 042 and 026 while thickening towards SW and NE, with shale intercalations. This pattern indicates deposition in a fluvial / tidal flood plain, channel, and deltaic front environments Etu-Effeotor\(^\text{65}\).

**Figure 11b:** Reservoir ‘B’ geometry across the wells. Arrow positions 5, 6 and 7 are relatively coarsening upward sequence across wells 048, 042 and 26; while arrow position 8 in well 032 is a prograding sequence from base and serrated/blocky in geometrical architecture upwards. Reservoir ‘B’ gradually thins out from north east to south west.

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\(^{65}\)Op. Cit
Reservoir ‘C’ thicken from northeast to southwest.

Reservoir ‘D’ thins out at centre for wells 042 and 026 and thickening at both flanks.

Reservoirs ‘B’, ‘C’, and ‘D’ (Figures 11 b, c, d), showed a serrated / saw-tooth shape across all the wells, which indicates rapid alternation of thin beds of shale with sandstones and implies deposition under differential alternations in low and high energy regimes. These facies are typical of marshy or swampy areas, lagoons and delta fronts environment\(^{66}\) as interpreted by Omoboriowo et al.\(^{67}\).


\(^{67}\)Op. Cit.
Table 4: Seismic characteristics and depositional facies interpretation for inline 4997

<table>
<thead>
<tr>
<th>Seismic Facies</th>
<th>Reflection Geometry</th>
<th>Reflection continuity</th>
<th>Amplitude</th>
<th>Depositional facies (inferred)</th>
<th>Depositional Environment (inferred)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit ‘A’</td>
<td>Sheet to wedge</td>
<td>Parallel to sub-parallel</td>
<td>Low to moderate</td>
<td>Massive sand body with shale intercalations</td>
<td>Low energy deltaic plain, and shelf margin shoreface environment</td>
</tr>
<tr>
<td>Unit ‘B’</td>
<td>Lens to wedge</td>
<td>Sub-parallel to convergent to oblique</td>
<td>Low to high</td>
<td>Thick sand body with inter-bedded shale deposit</td>
<td>Low - medium energy deltaic front, inner to middle neritic shelf margin &amp; paleo coastal environment</td>
</tr>
<tr>
<td>Unit ‘C’</td>
<td>Lens to channel shaped</td>
<td>Wavy to chaotic</td>
<td>Low to moderate</td>
<td>Offshore mud deposits, fine grain / laminated marine shale, prodelta shale complexes</td>
<td>Basin slope, lower slope and deep marine environment</td>
</tr>
</tbody>
</table>

Petrophysical analysis
The following petrophysical parameters were computed for reservoirs ‘C’ and ‘D’: Water saturation (S_w), Hydrocarbon Saturation (S_h), Volume of Shale (V_{sh}), Porosity (Φ) and Permeability (K). Results of average petrophysical parameters computed for reservoirs ‘C’ and ‘D’ is shown in Tables 5 and 6.

Table 5: Average petrophysical parameters of reservoir C

<table>
<thead>
<tr>
<th>Reservoir</th>
<th>Parameters</th>
<th>Well-048</th>
<th>Well-042</th>
<th>Well-026</th>
<th>Well-032</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>C</td>
<td>Top(ft)</td>
<td>8875.46</td>
<td>10350.29</td>
<td>10450.47</td>
<td>9313.28</td>
<td>9747.19</td>
</tr>
<tr>
<td></td>
<td>Base(ft)</td>
<td>9124.52</td>
<td>10650.43</td>
<td>10700.23</td>
<td>9524.51</td>
<td>9999.92</td>
</tr>
<tr>
<td></td>
<td>Gross Thickness(ft)</td>
<td>249.06</td>
<td>300.14</td>
<td>249.76</td>
<td>211.23</td>
<td>252.55</td>
</tr>
<tr>
<td></td>
<td>V_{sh} (%)</td>
<td>11.5</td>
<td>12.56</td>
<td>10.0</td>
<td>17.57</td>
<td>12.91</td>
</tr>
<tr>
<td></td>
<td>Net Thickness(ft)</td>
<td>239.22</td>
<td>286.65</td>
<td>240.21</td>
<td>194.41</td>
<td>240.31</td>
</tr>
<tr>
<td></td>
<td>Net/Gross</td>
<td>0.956</td>
<td>0.957</td>
<td>0.960</td>
<td>0.915</td>
<td>0.947</td>
</tr>
<tr>
<td></td>
<td>Φ(%)</td>
<td>30.85</td>
<td>29.06</td>
<td>26.54</td>
<td>27.39</td>
<td>28.46</td>
</tr>
<tr>
<td></td>
<td>K (mD)</td>
<td>2574.88</td>
<td>2288.6</td>
<td>1877.43</td>
<td>1933.98</td>
<td>2168.72</td>
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<tr>
<td></td>
<td>S_w (%)</td>
<td>31.15</td>
<td>32.24</td>
<td>32.68</td>
<td>30.57</td>
<td>31.66</td>
</tr>
<tr>
<td></td>
<td>S_{err} (%)</td>
<td>7.64</td>
<td>7.91</td>
<td>8.02</td>
<td>7.5</td>
<td>7.77</td>
</tr>
<tr>
<td></td>
<td>Sh (%) =1-Sw</td>
<td>68.85</td>
<td>67.76</td>
<td>67.32</td>
<td>68.85</td>
<td>68.34</td>
</tr>
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</table>
Table 6: Average Petrophysical parameters of reservoir D

<table>
<thead>
<tr>
<th>Reservoir</th>
<th>Parameters</th>
<th>Well-048</th>
<th>Well-042</th>
<th>Well-026</th>
<th>Well-032</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>D</td>
<td>Top(ft)</td>
<td>9200.78</td>
<td>10988.71</td>
<td>11075.27</td>
<td>9862.8</td>
<td>10281.89</td>
</tr>
<tr>
<td></td>
<td>Base(ft)</td>
<td>9375.22</td>
<td>11100.86</td>
<td>11188.22</td>
<td>10025.6</td>
<td>10422.48</td>
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<td>Gross Thickness(ft)</td>
<td>174.44</td>
<td>112.15</td>
<td>112.95</td>
<td>162.8</td>
<td>140.59</td>
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<td></td>
<td>Vsh (%)</td>
<td>11.89</td>
<td>11.32</td>
<td>10.47</td>
<td>13.97</td>
<td>11.91</td>
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<tr>
<td></td>
<td>Net Thickness(ft)</td>
<td>162.55</td>
<td>100.83</td>
<td>102.48</td>
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<td>Net/Gross</td>
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<td>0.9</td>
<td>0.907</td>
<td>0.914</td>
<td>0.91</td>
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<td>Ф(%)</td>
<td>28.81</td>
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<td>K (mD)</td>
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<td>1785.08</td>
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<td></td>
<td>S_w (%)</td>
<td>33.92</td>
<td>25.61</td>
<td>33.31</td>
<td>30.07</td>
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<td>S_wrr (%)</td>
<td>8.32</td>
<td>6.29</td>
<td>8.18</td>
<td>7.38</td>
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<td></td>
<td>Sh (%) =1-Sw</td>
<td>66.08</td>
<td>74.39</td>
<td>66.69</td>
<td>69.93</td>
<td>69.27</td>
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</table>

Reservoir ‘C’ occurs (from top to base) at depth range of (8875.46 – 9124.52 ft) in well-048, (10350.29-10650.43 ft) in well-042, (10450.47-10700.23 ft) in well-026 and (9313.28-9524.51 ft) in well-032. The petrophysical parameters for reservoir ‘C’ are shown in Table 5. The net sand thicknesses for reservoir ‘C’ across Well-048, 042, 026 and 032 are 239.22, 286.65, 240.21 and 194.41 ft, respectively (Table 5). Porosity values obtained for reservoir C in Table 4 are rated very good to excellent while permeability values are rated excellent based on Rider68 criteria. Also reservoir ‘D’ occurs (from top to base) at depths of (9200 - 9375.22 ft) in well-048, (10988731-11188.22 ft) in well-042, (11075.27 - 11188.22 ft) in well-026 and (9862.8 - 10025.48 ft) in well-032. With gross thicknesses of about 174.44 ft in well-048, 112.15 ft in well 042, 112.95 ft in well-026 and 162.8 ft in well-032 respectively. Porosity values obtained for this reservoir in Table 6 are rated very good to excellent while permeability values are rated excellent based on Rider69 criteria. Hydrocarbon saturation (S_{hc}) across the four wells have an average of 68.34% for reservoir ‘C’ and 69.27% for reservoir ‘D’. These high values of hydrocarbon saturation indicate low water saturation and imply that the reservoirs will produce water-free hydrocarbon at irreducible water saturation70 and testify to the excellent reservoir qualities in the field.

**Isochore Maps for reservoir ‘C’ and ‘D’**

An isochore map is a contour map that displays lines of equal vertical thicknesses within a layer or reservoir unit. In geology, isochore maps are usually referred to as true vertical thickness maps; unlike isopach map which displays lines of equal thicknesses in a layer whose thickness is measured perpendicular to the layer boundaries71,72. Isochore maps are particularly useful in analysing depositional trends and history of subsidence and faulting of an area.

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Isochore maps for reservoir ‘C’ and ‘D’ (Figure 12a & b) were generated to define the lateral continuity of both reservoirs. From the isochore maps, it was observed that reservoir ‘C’ has contour value of 30 ft (at well-048) with equal contour lines interval of 10 ft to 150 ft which covers the other wells; while reservoir ‘D’ has contour value of 160 ft (at well-048) with contour lines interval of 100 ft to 180 ft which covers the other wells in the field. This suggests that reservoir ‘D’ is thick (dense) while reservoir ‘C’ is thin (sparse). This implies that thicker sediments will accumulate at the flank of the area (towards reservoir ‘D’) and the depocenter is located downside of reservoir ‘D’ in Figure 12b. Dense sediment thickness in ‘D’ suggests increased tectonic activity during deposition, resulting in an increase in accommodation space, while low thickness variety suggests low tectonic activity during deposition73.

Conclusion
A comprehensive approach which integrates structural interpretation of 3D seismic data with well logs and seismostratigraphic interpretation has been used to unravel the structural pattern of subsurface geological structures in the study area. Petrophysical parameters of delineated reservoirs within four wells (Well-026, Well-032, Well-042 and Well-048) were analysed with the aim of evaluating the hydrocarbon plays and establishing a correlation between seismic facies and lithology. The depositional environment inferred is mostly tidal channel and shoreface environments. Depth structural map, RMS and variance attributes maps produced for reservoir horizons ‘C’ and ‘D’ indicate a highly faulted reservoir system with SE-NW sedimentation trend within a NE-SW oriented set of normal faults. The structural pattern of the area comprises normal faults and rollover structures which typify the tectonic setting of the Niger Delta Basin. The petrophysical parameters of the studied reservoirs indicate that they are highly prospective.

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