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# 3-D Seismic Attributes Analysis for Enhanced Hydrocarbon Prospect Definition of Onshore Fuba Field Niger-Delta, Nigeria

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***Abstract***
*3-D seismic attributes analysis for enhanced prospect definition of the onshore Fuba Field, Niger Delta, Nigeria using Well-log and 3D Seismic data are here presented. Well-to-Seismic ties, faults and horizon mapping, time-surface generation and seismic attributes generation were carried out using Petrel software. The structural interpretation of seismic data reveal highly synthetic and antithetic faults which are in line with faults trends identified in the Niger Delta. Of the 36 interpreted faults, only synthetic and antithetic faults are regional, running from the top to bottom across the field. These faults play significant roles in trap formation at the upper, middle and lower sections of the field. Three distinct horizons were mapped. For a comprehensive analysis of the structural and stratigraphic understanding of the reservoirs, four seismic attributes variance edge, sweetness, root mean square and relative acoustic impedance were applied to the seismic data. The variance values ranges from 0.0 to 1.0. The Variance edge analysis was used to delineate the prominent and subtle faults in the area. The sweetness value ranges from 0 to 22,500. The high sweetness regions in the seismic data indicate high amplitude which indicates the presence of hydrocarbon-bearing sand units. The RMS amplitude values range from 0 to 13,000 in the reservoirs. The root mean square amplitude analysis also indicates the presence of hydrocarbon in seismic data. The relative acoustic impedance analysis was used for delineating lithology variation in the seismic sections. In reservoirs, hydrocarbons were encountered by all seven wells drilled in the field.*

***Keywords:*** *Seismic attributes · Root mean square amplitude, Hydrocarbon prospects, Niger Delta, Nigeria*

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## I. Introduction

Seismic attributes are quantities of geometric, kinematic, dynamic, or statistical features obtained from seismic data [1, 2, 3, 4, 5]. Seismic attributes need to be integrated in some interpretations as they can be used as tools for predicting reservoir geometry and possibly displaying lateral changes in thickness including fluid contacts [6]. The geometrical attributes are used for structural and stratigraphic interpretations of seismic data. It is therefore possible to use seismic attribute to map geological features such as faults [7]. Seismic attributes are used in most seismic exploration and reservoir study to correctly image the subsurface geological structures, correctly characterize the amplitudes of the seismic data and to obtain information on reservoir properties [8, 9, 10, 11]. Improved methodologies are needed to discriminate between true hydrocarbon indicators and non-indicators by imaging the detail subsurface structure with a view to delineate new hydrocarbon zones that might be hidden in structural traps for the development programmes of the field.

**T**his study is taken from Fuba Field, Depobelt, Niger Delta, Nigeria. The ultimate deliverable of this study was 3-D seismic attributes analysis for enhanced hydrocarbon prospects definition of the area. The major components of our study are: (a) Well Correlation performed in order to determine the continuity of the reservoir sand across the field. (b) Seismic Interpretation which involves well-to-seismic tie, fault mapping, horizon mapping, time surface generation, and generation of seismic attributes. Seismic attributes were analyzed and reservoir properties predicted from the seismic attributes. This aids in giving more insight into 3-D seismic attributes analysis for enhanced hydrocarbon prospects definition

## II. Location and Geology of the Study Area

The proposed study area Fuba Field is located in the onshore Niger Delta region. Figure 1 shows the map of the Niger Delta region showing the study area. The Niger Delta lies between latitudes 4° N and 6° N and longitudes 3° E and 9° E [12]. The Delta ranks as one of the major oil and gas provinces globally, with an estimated ultimate recovery of 40 billion barrels of oil and 40 trillion cubic feet of gas [13]. The coastal sedimentary basin of Nigeria has been the scene of three depositional cycles [14]. The first began with a marine incursion in the middle Cretaceous and was terminated by a mild folding phase in Santonian time. The second included the growth of a proto-Niger delta during the Late Cretaceous and ended in a major Paleocene marine transgression. The third cycle, from Eocene to Recent, marked the continuous growth of the main Niger delta. A new threefold lithostratigraphic subdivision is introduced for the Niger delta subsurface, comprising an upper sandy Benin Formation, an intervening unit of alternating sandstone and shale named the Agbada Formation, and a lower shaly Akata Formation. These three units extend across the whole delta and each ranges in age from early Tertiary to Recent. They are related to the present outcrops and environments of deposition. A separate member of the Benin Formation is recognized in the Port Harcourt area. It is Miocene-Recent in age with a minimum thickness of more than 6,000ft (1829m) and made up of continental sands and sandstones (>90%) with few shale intercalations [15]. Subsurface structures are described as resulting from movement under the influence of gravity and their distribution is related to growth stages of the delta [16]. Rollover anticlines in front of growth faults form the main objectives of oil exploration, the hydrocarbons being found in sandstone reservoirs of the Agbada Formation.

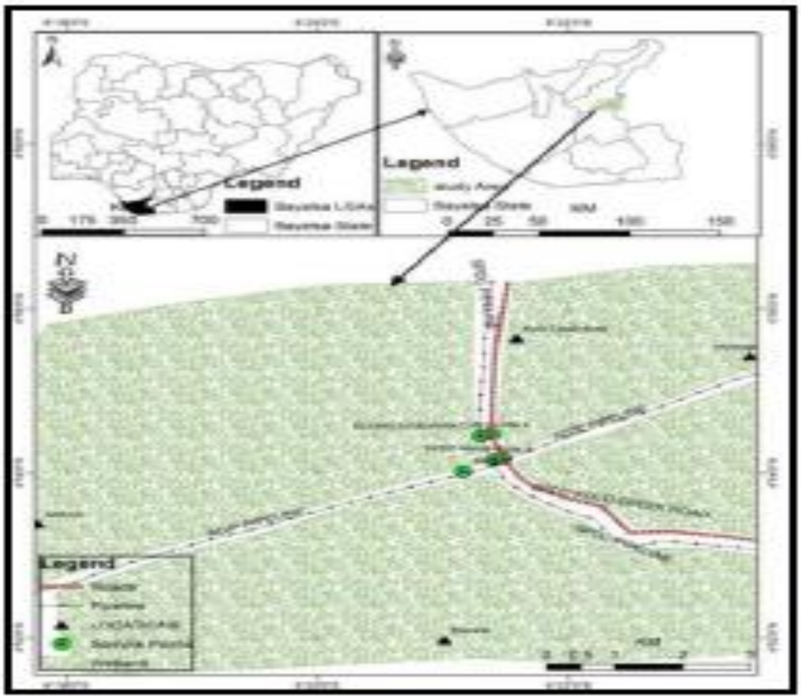


**Figure 1: Map of Niger Delta Oilfields showing the location of Fuba Field**

## III. Materials and Methods

### 3.1 Well-to-Seismic Ties

Well correlation is the first stage of the pre-interpretation process. The process of well correlation involves lithologic description, picking top and base of sand-bodies, fluid discrimination and then linking these properties from one well to another based on similarity in trends. In between these two lithologies in the subsurface, the gamma ray log is often used. Correlation of reservoir sands was achieved using the top and base of reservoir sands picked. The correlation process was possible based on similarity in the behavior of the gamma ray log the Niger Delta; the predominant lithologies are sands and shales. In order to discriminate shapes. Also, the thickness of the shale bodies overlying and underlying the sand body is considered during Correlation. After defining the lithologies, the resistivity log was used for discriminating the type of fluid occurring within the pores in the rocks.

There are five basic steps involved in seismic interpretation relevant to this study and they include; Well-to-seismic ties, Fault Mapping, Horizon mapping, Time surface generation and Attributes generation. Well-to-seismic tie is a process that enables the visualization of well information on seismic data. For this process to be achieved, the following are basic requirements; checkshot, sonic log, density log and a wavelet. The sonic log, which is the reciprocal of velocity, was calibrated using the checkshot data. The calibration process is necessary in order to improve the quality of the sonic log because the sonic log is prone to washouts and other wellbore related issues. The results of calibrating the sonic log with the checkshot gives a new log called the calibrated sonic log.

The calibrated sonic log is used along with the density log to generate an acoustic impedance (AI) log. The acoustic impedance log is calculated for each layer of rock. The next step involves generating the reflectivity coefficient (RC) log. The RC is calculated and generated using the AI log. The RC log generated is then convolved with a wavelet to generate a synthetic seismogram which is comparable with the seismic data. The statistical wavelet utilized for convolution is extracted from the seismic data. The synthetic seismogram was generated for every well that had checkshot, density and sonic log. The reflections on the synthetic seismogram were matched with the reflections on seismic data

Faults were identified as discontinuities or breaks in the seismic reflections. Faults were mapped on both inline and cross-line directions. Horizons are continuous lateral reflection events that are truncated by fault lines. The horizon interpretation process was conducted along both inline and crossline direction. At the end of the horizon mapping, a seed grid is generated which serves as an input for time surface generation. Time surfaces were generated using the seed grids gotten from the horizon mapping process.
Among the seismic attributes that have been used in the visualization of the geology of the subsurface are variance, root mean square amplitude, sweetness, and relative acoustic impedance. The seismic attribute analysis was applied to the seismic inline 8515.

**3.2 Determination of Root Mean Square (RMS) Amplitude**
The root mean square (RMS) amplitude was extracted from the seismic data as a surface attribute. Root mean square (RMS) amplitude is used to obtain a scaled estimate of seismic trace envelope. It is obtained in the software by sliding a tapered window of N samples as the square root of the sum of all the trace value x squared. The RMS attribute computation in Petrel software makes use of the inbuilt formula:

$$X_{rms} = \sqrt{\frac{1}{N}\sum_{n=1}^{N} w_n x_n^2} \qquad (1)$$

where $X_{rms} =$ root mean square amplitude, $w_n =$ window values, $N =$ number of samples in the window, $x =$ trace value.

**3.3 Variance (Edge Detection) Method**
In the Petrel software, the variance attribute uses an algorithm that computes the local variance of the seismic data through a multi-trace window with user-defined size. The local variance is computed from horizontal sub-slices for each voxel. A vertical window was used for smoothing the computed variance and the observed amplitude normalized. The variance attribute measures the horizontal continuity of the amplitude that is the amplitude difference of the individual traces from their mean value within a gliding CMP window.

$$\sigma^2 = \frac{1}{n}\sum_{f_i=1}^{n}(x_i + x_m)^2 \qquad (2)$$

Where $\sigma =$ standard deviation, $\sigma^2 =$ variance, $n =$ the number of observations, $f_i =$ frequency
$x_i =$ the variable, $x_m =$ mean of $x_i$ .

**3.4 Determination of Relative Acoustic Impedance**
The acoustic impedance inversion transforms the seismic data into an acoustic impedance model. The acoustic impedance of a media is given as

$$AI = \rho v \qquad (3)$$

where AI = acoustic impedance, ρ = density, v = velocity.
To measure acoustic impedance, it is necessary to use seismic inversion. It was assumed that the input seismic data has been processed to reduced noise and multiples, and also contains zero phase and large bandwidth. The seismic trace represents a band-limited reflective series;

$$f(t) = \frac{1}{2}\frac{\Delta\rho\upsilon}{\rho\upsilon} \qquad (4)$$

where $f(t) =$ seismic trace, $\Delta\rho\upsilon =$ the difference in the product of density and velocity. The integration of the seismic trace will provide a bandlimited estimate of the natural log of the acoustic impedance. Since the integration of band-limited, the impedance will not have absolute magnitude values and consequently is only relative.

Relative acoustic impedance is an estimated inversion computed by the integration of seismic trace accompany by a high cut Butterworth zero-phase filter. It is a simplified inversion and has been generated as an asynchronous attribute in the software. It enhances acoustic impedance contrast boundaries. According to Taner [17], the relative acoustic impedance (RAI) can be computed by integrating the real part of the seismic trace.

$$\ln(\rho v) = 2\int_{t-0}^{t=1} f(T)dt \qquad (5)$$

Where $f(T)$ = real part of seismic trace. A Butterworth filter is then applied to remove long-wavelength trends that originated from the integration process [18].

$$BL(f) = \frac{1}{1+(\frac{f}{f_H})^{2N}} \qquad (6)$$

where $BL(f) =$ band –limited signal in frequency; $f_H$ = frequency cut-off value of 10 Hz, $N$ = filter order of 3.

It is used for delineating sequence boundaries, unconformity surfaces, and discontinuities. The acoustic impedance may be related to the formation porosity and the presence of fluid in a hydrocarbon reservoir.

### 3.5 Determination of Sweetness

Sweetness involves the implementation of envelopes and instantaneous frequency that are combined. Mathematically, it is expressed as

$$S(t) = \frac{\alpha(t)}{\sqrt{f_\alpha(t)}} \qquad (7)$$

where $S(t)$ = Sweetness, $\alpha(t)$ =Envelope, $f_\alpha(t)$ = instantaneous frequency.

Sweetness is used for the identification of features where the total energy signatures change in the seismic data.

## IV. Results and Discussion

### 4.1 Reservoir Identification and Correlation

The results for lithology and reservoir identification are presented in (Figure 2). A total of fifteen sand bodies (A, B, C, D, E, F, G, H, I, J, K, L, M, N and O) were identified and correlated across all seven wells in the field. Three reservoir sands were selected for the purpose of this study (M, N and O). The resistivity logs which reveals the presence of hydrocarbons were used to identify the hydrocarbon bearing sands. On (Figure 2), the sands are coloured yellow while shales are grey in colour.

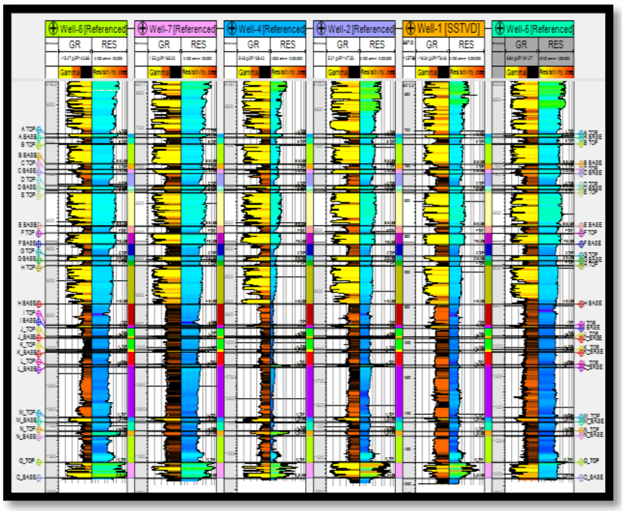


**Fig 2: Well section showing reservoir identified and correlated across Fuba Field**

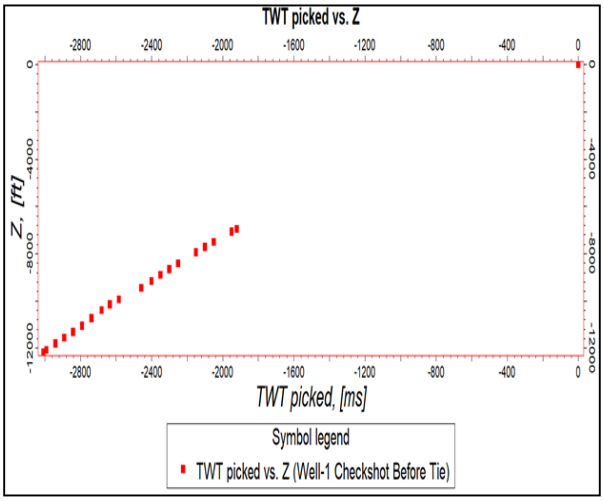


**Figure 3: Quality of Well-1 Checkshot utilized for well-to-seismic Tie**

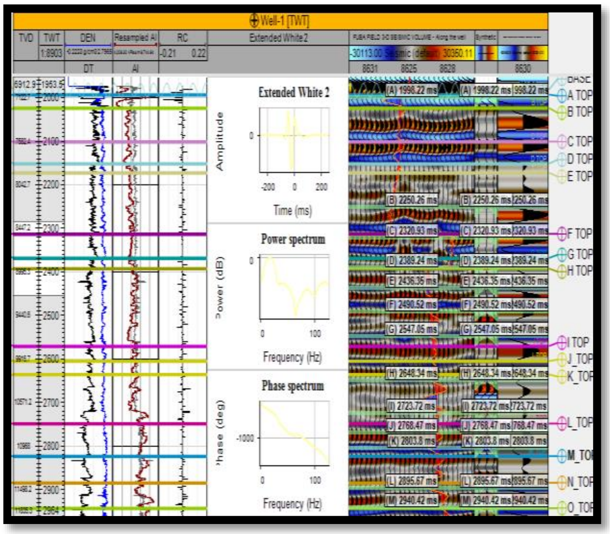


**Figure 4: Synthetic seismogram generation and well-to-seismic tie conducted for Fuba Field using Well-1 Checkshot**

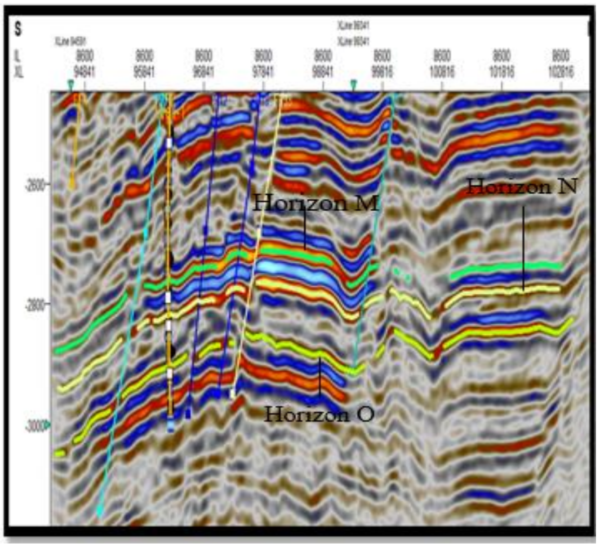


**Figure 5: Faults and horizon interpreted along seismic inline section**

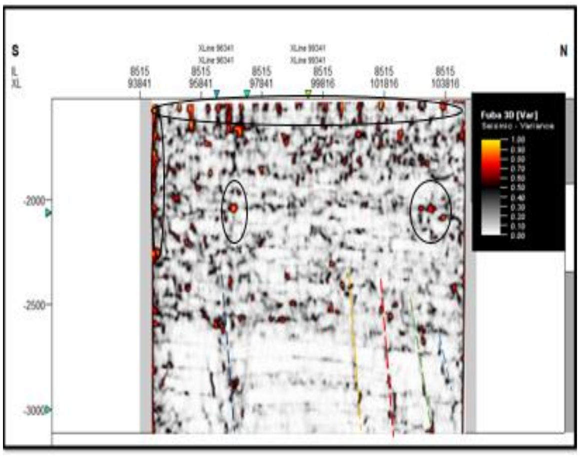

**Figure 6: Variance edge inline 8515**

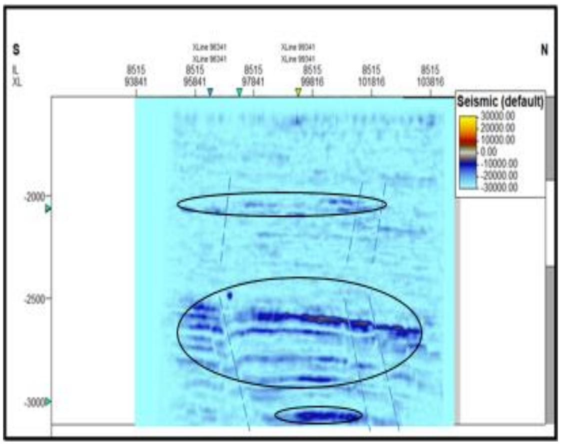


**Figure 7: Sweetness inline 8515**

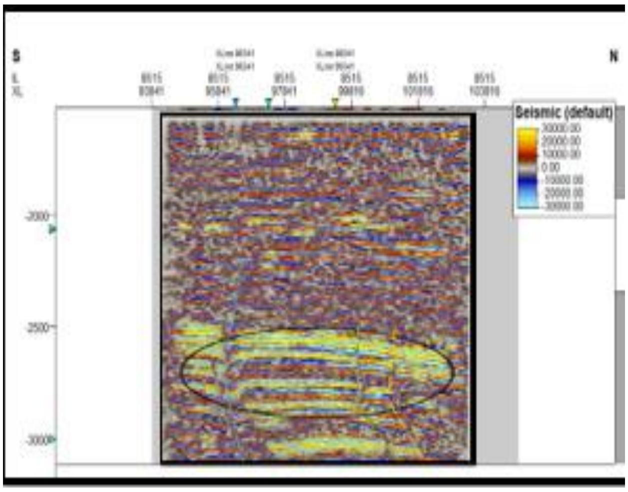


**Figure 8: Relative acoustic impedance inline 8515**

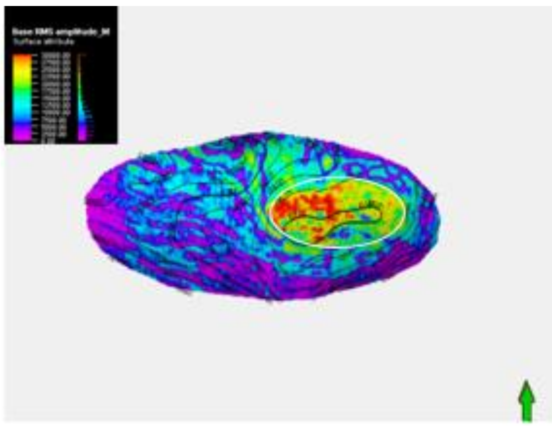

**Figure 9: Surface M RMS Amplitude Map**

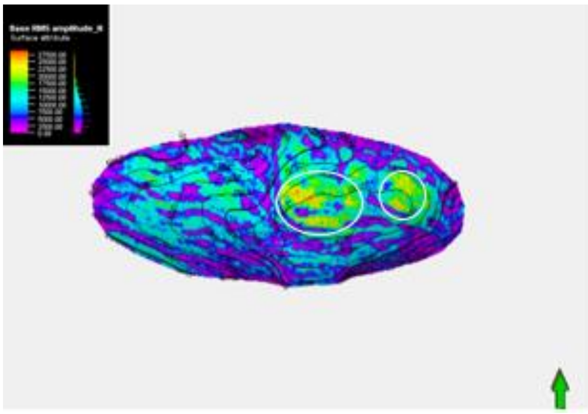

**Figure 10: Surface N RMS amplitude map**

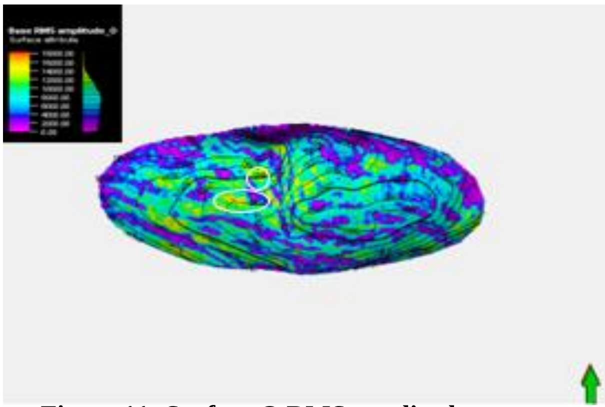

**Figure 11: Surface O RMS amplitude map**

**4.2 Well-to-seismic Tie**

The quality of Well-1 checkshot utilized for well-to-seismic tie is shown in Figure 3. The results for well-to-seismic tie conducted on Fuba field using density log, sonic log and checkshot of Well-1 is presented in Figure 4. An extended white 2 wavelet was used to give a near perfect match between the seismic and synthetic seismogram.

**4.3 Fault and Horizon Interpretation**

The results for the interpreted faults in Fuba field are presented in Figure 5 shows both synthetic and antithetic faults interpreted along seismic inlines. Faults are more visible along the inline direction because this direction reveals the true dip position of geologic structures. The variance time slice was used to validate the interpreted faults. All interpreted faults are normal synthetic and antithetic faults. A total of thirty-six faults were interpreted across the entire seismic data. Of the 36 interpreted faults, only F1 (synthetic fault) and F16 (antithetic fault) faults are regional, running from the top to bottom across the field. Hence, these faults play significant roles in trap formation at the upper, middle and lower sections of the field.

The results for the interpreted seismic horizons (Horizon A and Horizon I) are also presented in Figure 5. On these horizons, the fault polygons were generated and eliminated. The horizons were used as inputs for the generation of reservoir time surfaces.

**4.4 Seismic Attributes**

A series of seismic volume attributes such as variance edge, sweetness, relative acoustic impedance, and Root Mean Square (RMS) amplitude were generated in Petrel software interface to investigate potential structural and stratigraphic controls within the study area.

Figure 6 shows the computed variance attributes of the seismic section. The variance values range from 0.0 to 1.0. Values of variance equal to 1 represent discontinuities while a continuous seismic event is represented by the value of 0. The high values are denoted with red to yellow colorations.

On the variance map, the areas dotted with blue, green, orange and pink colored lines signify values that correspond to the location of the discontinuity. The discontinuities may be interpreted as faults and boundaries as shown by the lines drawn on the variance attribute map [19]. The variance edge enhanced the faults or sedimentological bodies within the seismic data volume. Furthermore, several bright spots are also delineated (in black circles and black ovals) which indicate high reflectivity sediments compared to their surroundings. These bright spots are an indication that a potential hydrocarbon trap might exist in the area. The darkest regions in the seismic section, which make vertical stripes, may be interpreted as faults or fractures. The zones with low variance values are due to similar seismic traces. Areas with red patches represent lineaments/discontinuities while grey areas represent the structural framework of the field.

The variance attribute is edge imaging and detection techniques. It is used for imaging discontinuity related to faulting or stratigraphy in seismic data. Variance attribute is proven to help in imaging of channels, fault zones, fractures, unconformities and the major sequence boundaries [20].

Figure 7 represents the sweetness values of the seismic data. The sweetness value ranges from 0 (blue) to 22,500 (yellow). High sweetness values may be attributed to both high amplitude and low frequency while low sweetness value is as a result of low amplitude and high frequency in the seismic volume.

The high sweetness regions within the seismic data (circled in black) indicate high amplitude. They are interpreted as hydrocarbon-bearing sand units. Though the sweetness attribute is effective for channel detection and characterization of gas-charged bearing sand units, it is known to be less effective when the acoustic impedance contrast between shale and sand units are low and when both lithology units are high. In most cases, shale intervals are characterized by low amplitude (low acoustic impedance contrasts) and high frequency thereby indicating low sweetness. Sand intervals are characterized by high amplitude (high acoustic impedance contrast with the shales) and low frequencies, thus indicating high sweetness values. Sweetness is used for identifying sweet spots that are hydrocarbon prone. The high sweetness values in the seismic section are possible indications of oil and gas [21, 22, 23].

The relative acoustic impedance generated in the study area is shown in Figure 8. Based on the map, the yellow and red colours represent the highest relative impedance (in black circles) while the lowest relative impedance is represented by the blue colour.

The relative acoustic impedance attribute represents apparent acoustic impedance or physical property contrasts. It is commonly used for lithology discrimination, thickness variation and sequences boundaries indicators associated with high contrasts in acoustic impedance values. It may also indicate unconformity surfaces, discontinuities, porosity and the presence of hydrocarbon in a reservoir [24]. The high relative acoustic impedance values are associated with shalier facies while lower values correspond to sand intervals [25, 26]. The high relative acoustic impedance may also be interpreted as sequences boundaries.

The RMS amplitude was generated for all the studied surfaces (surface M, N and O). The result of the RMS amplitude analysis is presented in table 1 while Figures 9-11 show the RMS amplitude maps. The RMS amplitude values range from 0 (purple) to 13,000 (red) in reservoir M, from 0 (purple) to 12,000 (red) in reservoir N and 0 (purple) to 9,000 (red) in horizon O. The red-yellowish colour represents hydrocarbon sands. Some of these hydrocarbon sands were not detected in the original seismic section. The observed changes may be due to changes in lithology or fluid content.

The RMS attribute is related to the variations in acoustic impedance. The higher the acoustic impedance values, the higher the RMS amplitude. The high values of RMS amplitudes may also be related to high porous sands, which are potential hydrocarbon reservoirs. RMS amplitude is similar to reflection strength and it is used in seismic exploration for delineating bright spots and amplitude anomalies [27, 28, 29]. The RMS amplitude is used for identifying coarser-grained facies, compaction related effects, and unconformities. The high values of RMS amplitudes circled (in white circles) in the maps are interpreted as high porosity lithologies, such as porous sands. These high RMS amplitude segments are potential high quality hydrocarbon reservoirs.

The high amplitude (in white circles) in the seismic data conforms to the structures and confirm the presence of hydrocarbon [30]. The high amplitude ranges from light blue to yellow and red coloration. Root mean square amplitude is used as a good indicator of the presence of hydrocarbon in seismic data.

**Table 1: RMS Amplitude Values for the Surfaces**

| **Reservoir** | **Range of RMS Amplitude Values** |
|---|---|
| Reservoir-M | 0 – 13,000 |
| Reservoir _N | 0 – 12,000 |
| Reservoir _O | 0 – 9,000 |

## V. Conclusion

A total of fifteen sand bodies (A, B, C, D, E, F, G, H, I, J, K, L, M N and O) were identified and correlated across all seven wells in the field. All interpreted faults are normal synthetic and antithetic faults. A total of thirty-six faults were interpreted across the entire seismic data. Of the twenty-nine interpreted faults, only F1 (synthetic fault) and F4 (antithetic fault) faults are regional, running from the top to bottom across the field. Hence, these faults play significant roles in trap formation at the upper, middle and lower sections of the field. Three horizons (M, N and O) were selected for the study. The seismic attributes interpreted include variance, relative acoustic impedance, root mean square amplitude and sweetness. The variance revealed the subtle structures and faults in the seismic section. The RMS amplitude, sweetness and relative acoustic impedance results highlighted the hydrocarbon zones. The seismic attribute analysis in this study has helped in increasing the understanding of the delineated reservoirs and geological structures in the study area towards a better delineation of hydrocarbon potential and improved reservoir characterization. Furthermore, it has been demonstrated that seismic attributes are complementary to the information derived through traditional methods of seismic interpretation. Extraction of seismic attributes can bring to fore new information and insights into stratigraphic and structural interpretations. Hydrocarbon exploration and development risks can be reduced greatly with the outcome of seismic attributes extraction and analysis. It is recommended that careful quality control of the updated velocities using existing horizons should be performed so that the resulting velocity maps can be used for accurate depth conversion. Finally, fault seal analysis should be carried out to confirm that the suspected trapping faults are not leaking in which case they serve as conduits for hydrocarbon migrations rather than lateral barriers to hydrocarbon escape.

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