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Application of Seismic Attributes to Reservoir Modelling and Characterization

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Abstract

Reservoirs are modelled to reveal geological features especially structural traps on hydrocarbon prospects in a given field. Seismic attribute is applied to model the Tomboy field reservoir to indicate prospective drilling locations where there is high net to gross value in the field. Structures were mapped using seismic methodology and determine environment of deposition using well logs. Major strata terminations such as on-laps, erosional unconformities were recognized. Well logs were effectively tied to seismic lines to ensure effective seismic interpretation. Sandstone depicts negative amplitude while shale depicts positive amplitude. Four horizons were mapped and the mapped horizons were converted into surfaces. The generated surfaces were also used in locating the Maximum Flooding Surfaces in the depositional environment of the lithology and a zone which is term “Area of Complex Geology”. The structural style of field is characterized by systems of normal faults, listric faults, horst faults and growth faults. Three wells from the Tomboy Field (TMB-2, TMB-5 and TMB-7) were correlated and there was continuity in the progression of the lithology. The seismic attributes showed the effect of time and amplitude on reservoir modelling which is affected by porosity and lithology. Seismic attributes within the framework of this research was used to provide good information about the mapped reservoirs and identified structural traps towards a better delineation of hydrocarbon prospects and improved reservoir modelling via fault and horizon models

Keywords: Reservoirs, Unconformities, Attributes, Horizons, Structural traps, Hydrocarbon and Lithology.

Introduction

The upstream oil industry involves finding hydrocarbon deposits, developing them, and producing the hydrocarbons for commercial use. Over the past few decades, numerous technological advances in the oil industry, e.g. remote detection, identification of hydrocarbons, and extended reach drilling, have increased the success rate of finding reserves, made it possible to develop them and improved the recovery from existing resources. In addition, advances in computing capabilities have enabled geologists and engineers to model the reservoirs with increasing accuracy. In order to meet the ever increasing global hydrocarbon demand, heavy capital investments and continuous technological advances are required (Branets L.V. et.al, 2009).

Various technologies used to understand a prospective reservoir provide information at many different scales. Core plugs are a few inches in size. Well logs can detect properties within a few feet around the well. Seismic imaging covers a huge volume, but its typical resolution is limited to a few meters vertically and tens of meters horizontally. Limited by time and capital, direct sampling of reservoir rock and fluid properties is sparse. Therefore, geologic interpretations based on seismic information and understandings of sedimentary processes are used to interpolate or extrapolate the measured data in order to yield complete reservoir descriptions. Information provided by these technologies is incorporated into reservoir models. Constructing reservoir models has become a crucial step in resource development as reservoir modelling provides a venue to integrate and reconcile all available data and geologic concepts.

Seismic attributes can be conveniently defined as “the quantities that are measured, computed or implied from the seismic data” (Subrahmanyam, 2008). From the time of their introduction in early 1970s, seismic attributes have gone a long way and they became an aid to geoscientists for reservoir characterization. Seismic attributes provides a link between rock properties and seismic data. They are directly or indirectly related to rock properties, and are measured directly from seismic data (Chopra & Marfurt 2006).

In most exploration and reservoir seismic surveys, the main objectives are, first, to correctly image the structure in time and depth and, second, to correctly characterize the amplitudes of the reflections. If all amplitudes are accurately rendered, additional features known as seismic attributes can be derived and used in interpretation (Taner, 1979). The simplest attribute, and the one most widely used, is seismic amplitude, and it is usually reported as the maximum (positive or negative) amplitude value at each sample along a horizon picked from a 3D volume. It is fortunate that, in many cases, the amplitude of reflection corresponds directly to the porosity or to the saturation of the underlying formation.

The aim of this thesis is to apply seismic attributes in generation of a reservoir model.
The objective of this study is to generate a reservoir model via seismic attributes and well log data information. Analysis of this model can be used to predict regions of high reservoir productivity.

Study Area

The area of study, Tomboy field, is located within the western margin of offshore Niger Delta (Figure 1). The Niger Delta is situated in the Gulf of Guinea on the west coast of Central Africa. Niger Delta lies between latitudes 4° and 6° N and longitudes 3° and 9° E in the south-south geo-political region of Nigeria (Ojo E.A. et al, 2009). The Cenozoic Niger Delta is situated at the intersection of the Benue Trough and the South Atlantic Ocean where a triple junction developed during the separation of South America and Africa in the Late Jurassic (Obaje, S.O. 2013).

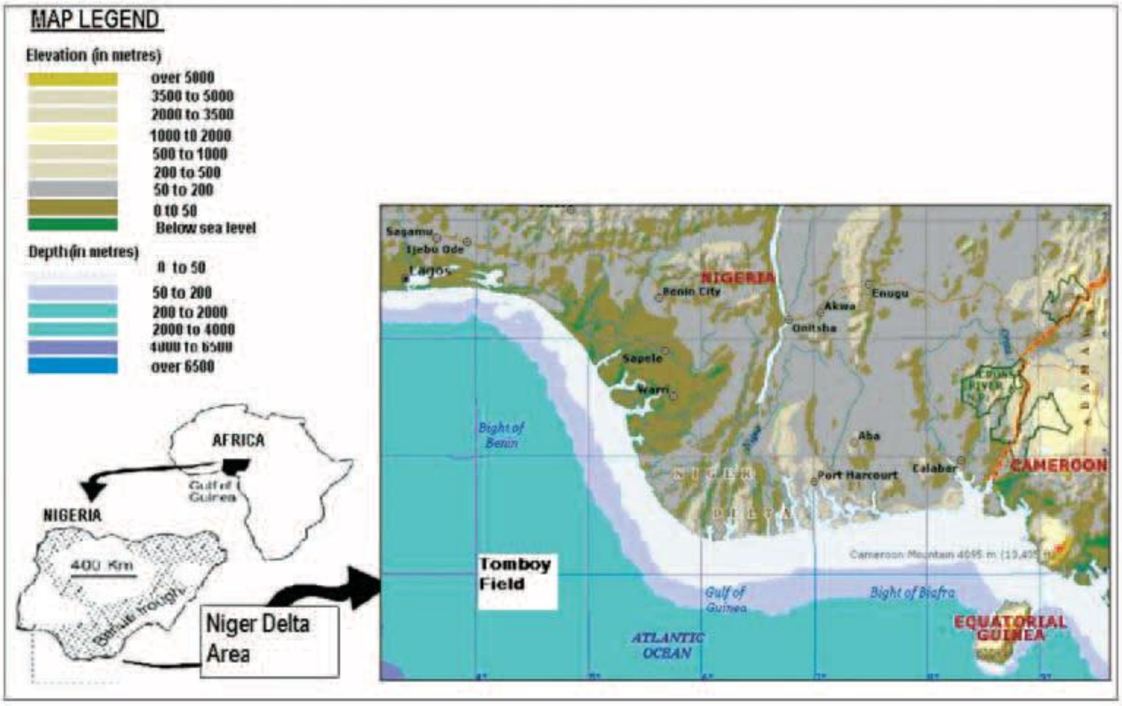

Figure 1: Location map of the study area (Modified from Owoyemi, 2004)

The Tertiary section of the Niger Delta is divided into three formations, representing prograding depositional facies that are distinguished mostly on the basis of sand- shale ratio. The type sections of these formations are described by (A.A. Avbovbo, 1978) and (K.C. Short and A.J. Stäuble, 1965). The Niger Delta Province contains only one identified petroleum system. This system is referred to as the Tertiary Niger Delta (Akata- Agbada) petroleum system (Oyeyemi, K.D. & Aizebeokhai, A.P, 2015).

THE AKATA FORMATION is the basal unit of the Tertiary delta complex. This lithofacies is composed of shales, clays, and silts. **THE AGBADA FORMATION** overlies the Akata Formation. It is represented by an alternation of sands (fluviatile, coastal, fluviomarine), silts, clays, and marine shales. **THE BENIN FORMATION** is the topmost sequence of the Niger Delta clastic wedge. It consists of massive continental (non-marine) sands (Emudianughe J.E. et al 2015).

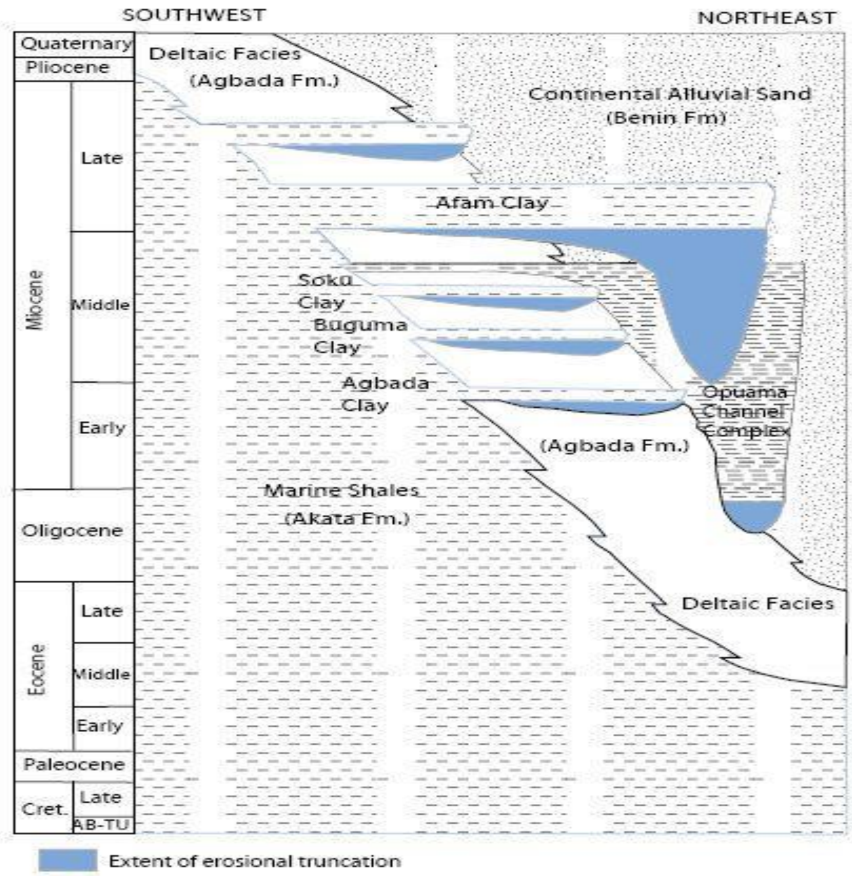

Figure 2: Stratigraphic column showing the three formations of the Niger Delta (Tuttle et al.1999). Modified from Doust and Omatsola (1990)

Methodology

Research Workflow

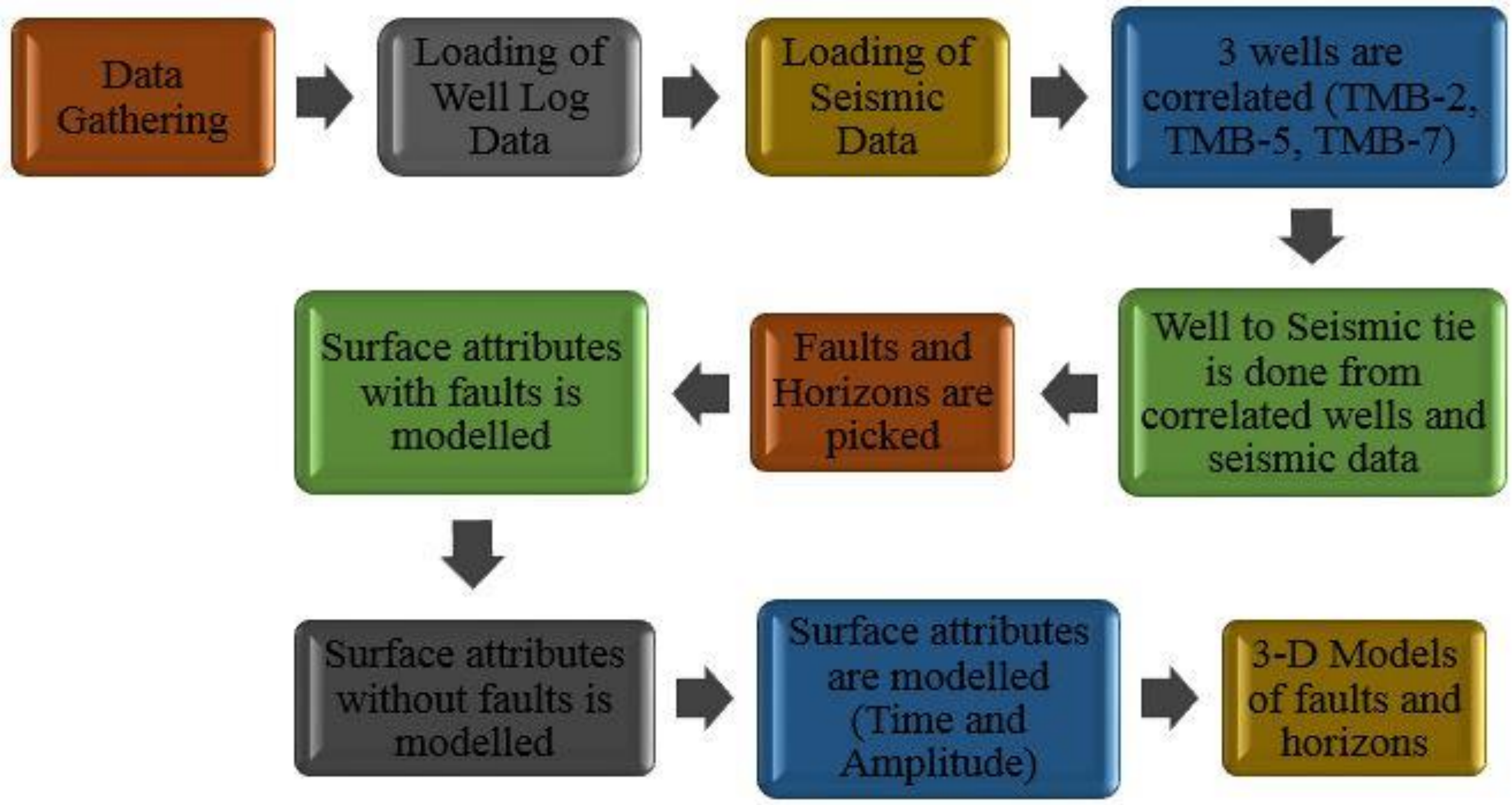

Figure 3: Research Work flow

The data used for this study are seismic, well logs, check shot data for 7 wells in the study area which is the Tomboy Field. It is a secondary data. The logs included were TMB-1, TMB-2, TMB-4, TMB-5, TMB-6, TMB-7, and TMB-9 where TMB is the abbreviation of Tomboy. The data set is owned by ChevronTexaco Nigeria Limited. The logs

were recorded in LAS file format. Out of the 7 imported logs, only
TMB-2, TMB-5 and TMB-7 were used.

The seismic dataset consists of Inline (dip) range 5800 to 6200 and Xline (strike) range 1480 to 1700. The 3D seismic volume data was recorded in SEG-Y format.

Importation of Data/Well Correlation

Data were edited (conditioned and dispiked) to remove poor data points before they were imported into the Petrel work platform. From the displayed logs, potential sand beds, identified from high resistivity signatures, were correlated to ascertain any stratigraphic discontinuity/continuity (fig 4a).

Well to Seismic Tie

Well events were tied to seismic events, with suite of logs (Gamma, calibrated sonic and density logs) and 2-D seismic volume. This was done to see the potential sand beds on the seismic volume, fig 6. Well to seismic tie provides the fundamental link between well and seismic events.

Fault/Horizon Mapping

Series of faults system were mapped (picked) to see both the structures trapping hydrocarbon in the sand beds and the complexity of geology of the study area, fig7 and 8. Surfaces and Surface attribute were generated from the fault systems on the sand beds (Horizons). A total of 6 faults were mapped across the seismic section. 2 major faults (F1 and F3) which were visible across the seismic section and 4 minor faults (F2, F4, F5, and F6) which were visible only in a particular region were mapped (Figure 7 and Figure 8).

Results and Discussion

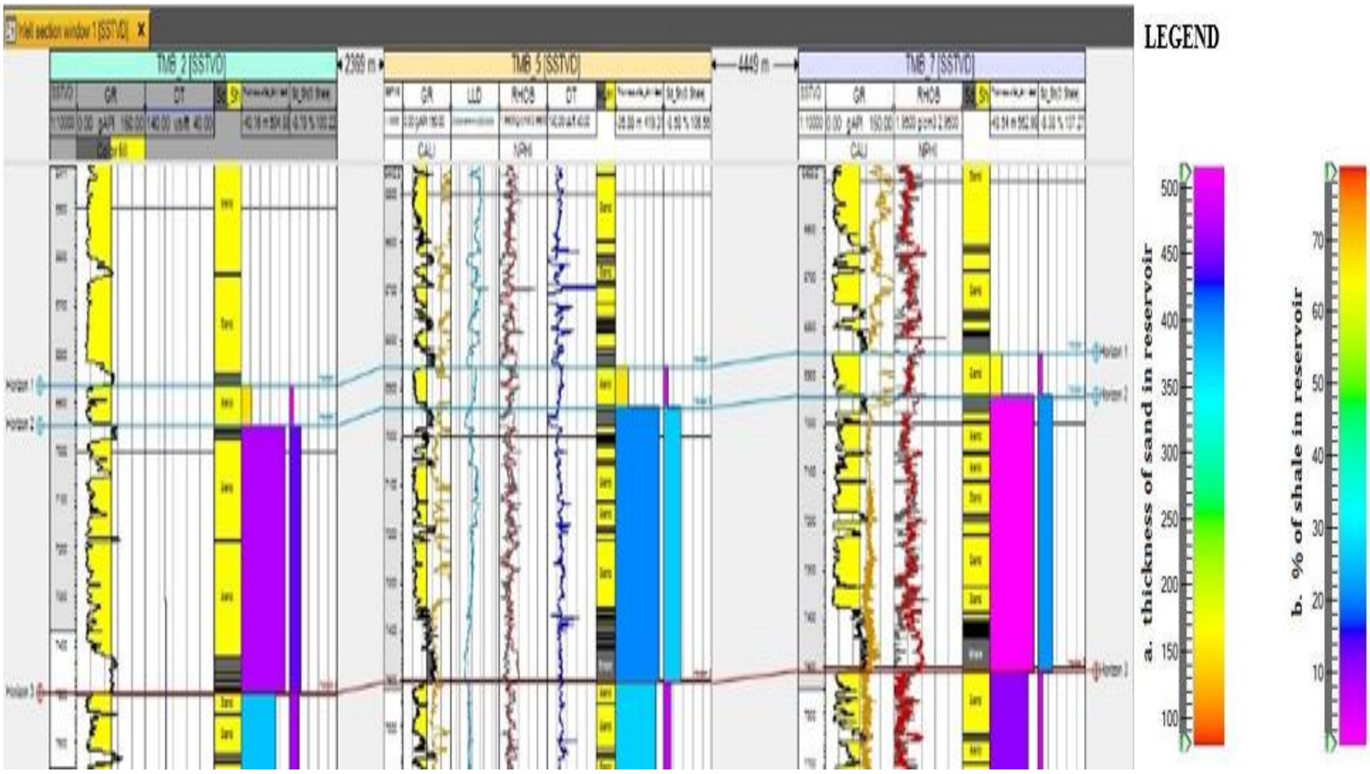

Figure 4a: Well correlation of TMB-2, TMB-5, and TMB-7

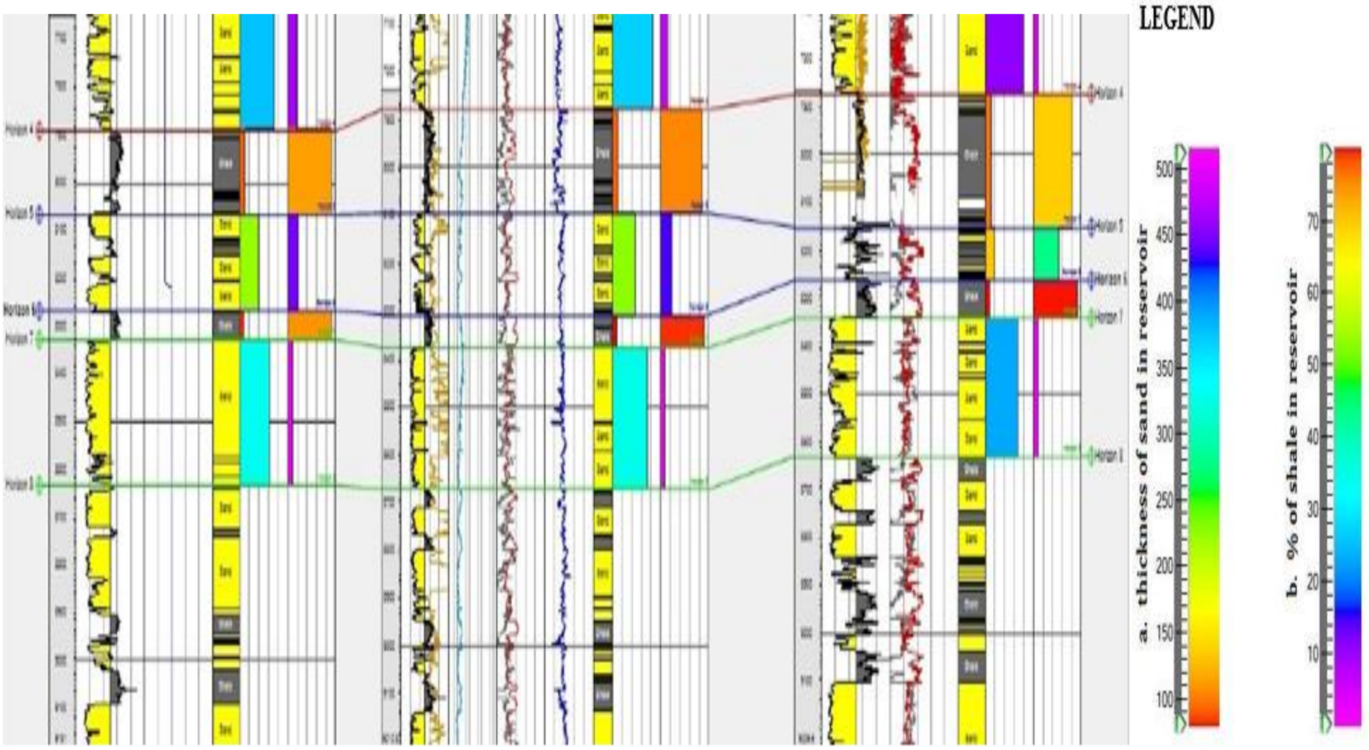

Figure 4b: Well correlation of TMB-2, TMB-5, and TMB-7

In figure 4a and 4b, 3 wells (TMB-2, TMB-5 and TMB-7) were correlated. Gamma ray log was used to identify lithology. From the log, the yellow colour indicates sand while ash colour indicates shale. Eight horizons were mapped and correlated. The region of the log (depth interval) studied was between 6850ft and 8650ft. This region is highly dominated by sand bodies which indicate the reservoir potential of the formation.

It was observed that there was continuity of events of deposition of the sand sediments across the three wells. The sand sediments were medium to well sorted across the three wells. The sand sediments have a coarsening upward sequence. The agent of transportation of the sediments is believed to be water due to the degree of sorting (medium to fine) which can infer that the depositional environment of the sediments is marine environment.

Well Correlation Spreadsheet

Table 1: Well Correlation Spreadsheet

	Well	Start MD	Zone log	TVT zone	TST zone	Thickness of Sd_Sh(1: Sand)	Sd_Sh(0: Shale)
1	TMB_2	6908.23	Zone 1			81.77	0.30
4	TMB_2	6990.25	Zone 2			459.46	16.57
7	TMB_2	7540.96	Zone 3			350.54	11.30
10	TMB_2	7936.14	Zone 6			17.58	90.01
19	TMB_2	8112.08	Zone 7			170.66	15.37
22	TMB_2	8313.74	Zone 4			5.26	91.13
13	TMB_2	8373.08	Zone 5			297.29	2.60
2	TMB_5	6896.96	Zone 1			83.63	1.23
5	TMB_5	6981.63	Zone 2			381.38	32.53
8	TMB_5	7546.89	Zone 3			342.07	8.21
11	TMB_5	7919.57	Zone 6			16.93	92.20
20	TMB_5	8136.69	Zone 7			174.50	18.10
23	TMB_5	8349.77	Zone 4			2.06	96.97
14	TMB_5	8417.56	Zone 5			292.58	1.01
3	TMB_7	7424.84	Zone 1			104.91	1.26
6	TMB_7	7531.09	Zone 2			512.02	26.51
9	TMB_7	8227.77	Zone 3			442.98	4.02
12	TMB_7	8689.32	Zone 6			25.01	84.83
21	TMB_7	9050.26	Zone 7			66.74	53.23
24	TMB_7	9192.96	Zone 4			2.42	97.63
15	TMB_7	9295.17	Zone 5			364.98	2.34

The spreadsheet reveals values of sand thickness and shale percentage of each zone across the three wells. This is aided by the values from the colour code in the legend of Figure 4. From the Well Correlation spreadsheet, each zone from each well reveals the corresponding values of the thickness of Sand and percentage of Shale in the reservoir. For example, in Well (TMB_2), at Zone 2, the value of thickness of Sand is 459.46m, while the value of percentage of Shale is 16.57% which reveals that there is more of Sand deposits than Shale deposits in that zone. This can be confirmed by the colours in the Legend. From the correlation, the colour of Sand in zone 2 is purple, while that of Shale is blue. And from the Legend, the purple colour in Sand ranges between 450-500m (in value), while the blue colour in Shale is between 10-20% (in value).

Well to Seismic Tie (synthetic seismogram)

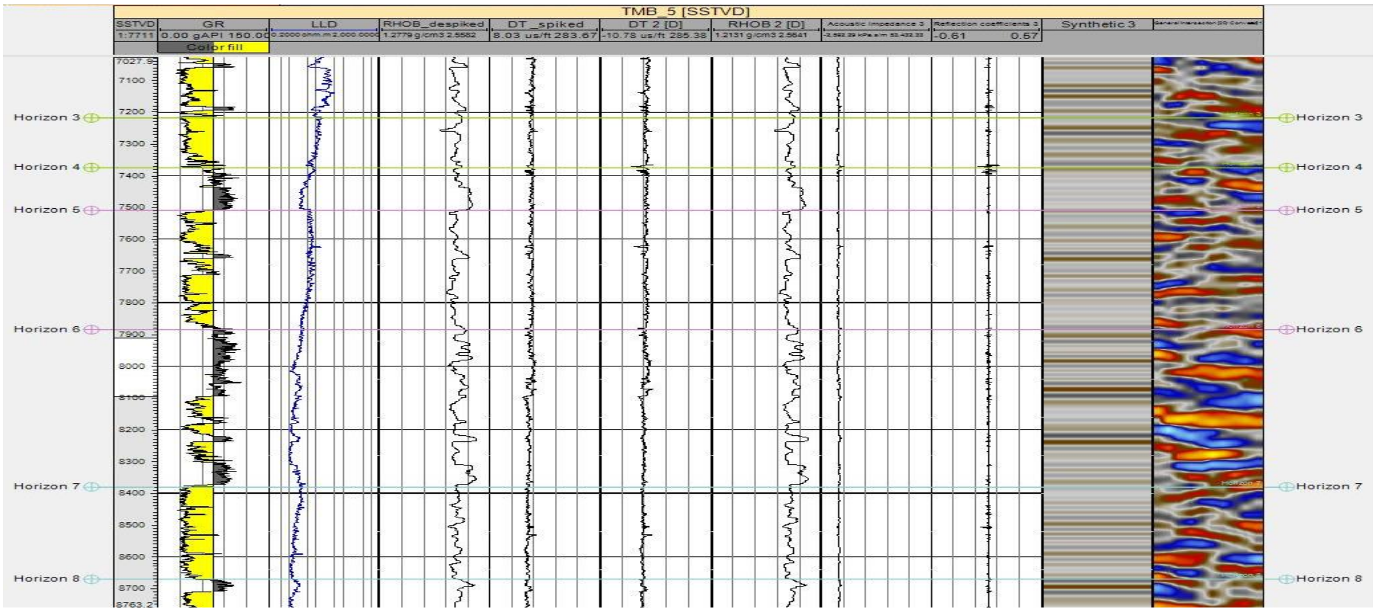

Figure 6: Well to Seismic Tie (Synthetic Seismogram)

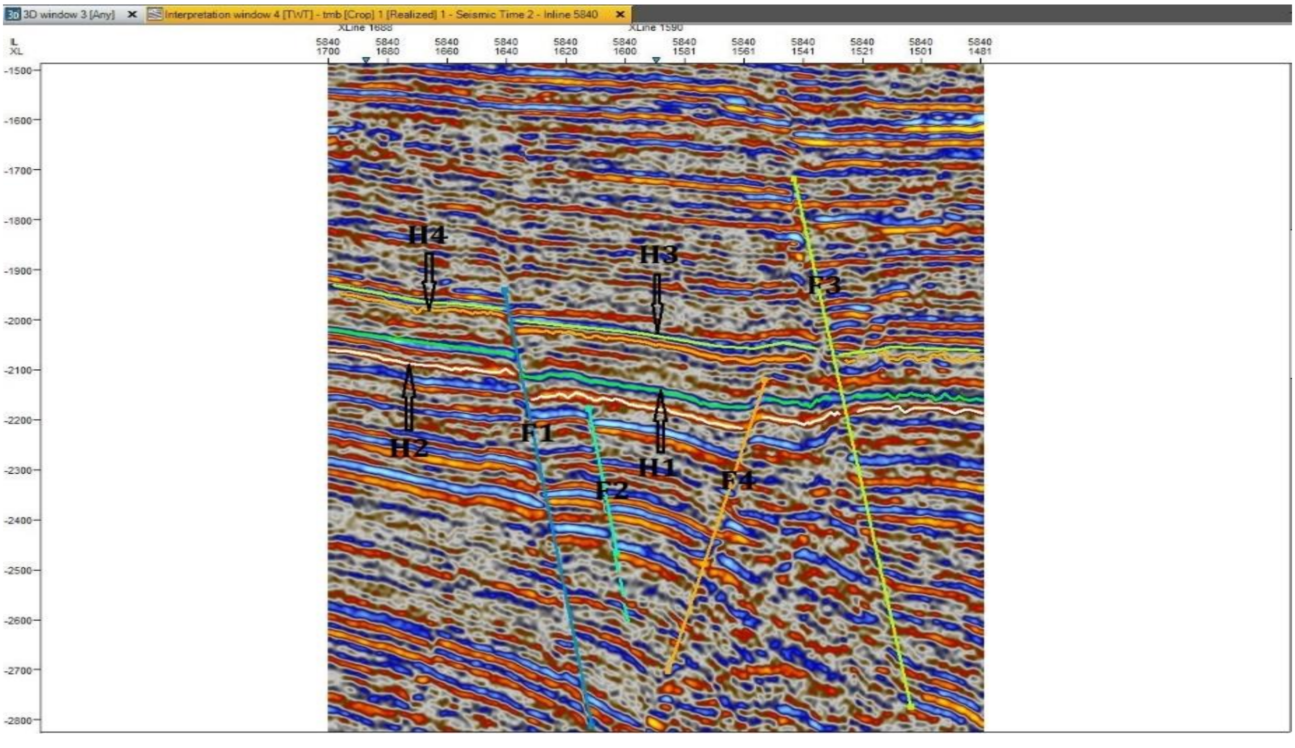

Figure 7: Faults F1, F2, F3, F4 with Horizons H1, H2, H3, H4

At Inline 5840, faults labelled F1, F2, F3 and F4 with horizons labelled H1, H2, H3 and H4 were mapped. Major faults F1 and F3 were identified while faults F2 and F4 were minor faults. Here, synthetic and antithetic faults were noticed. These faults may be accompanied by rollover anticlines because in the Niger Delta Structural Style, synthetic and antithetic faults are usually associated with rollover anticlines. Fault F1 is a normal fault, F2 is synthetic fault, F3 is a reverse fault, while F4 is antithetic fault.

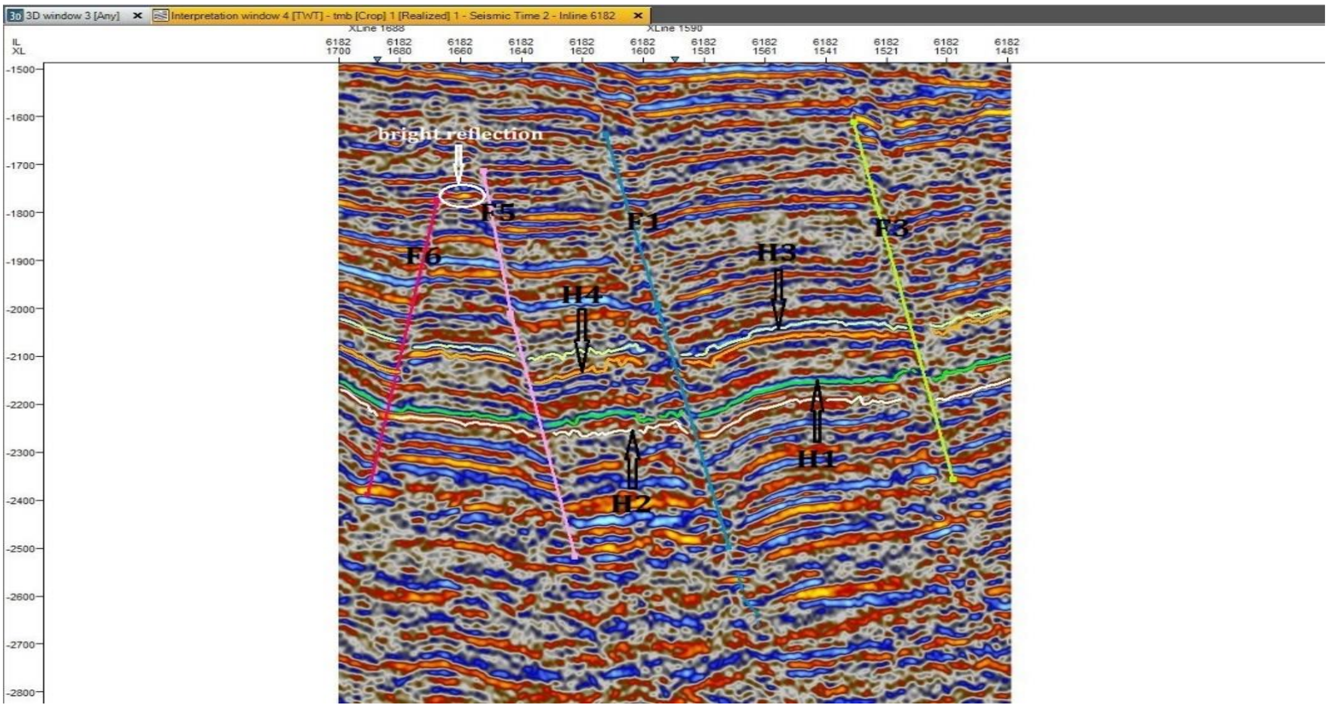

Figure 8: Faults F1, F3, F5, F6 with Horizons H1, H2, H3, H4

At Inline 6182, faults labelled F1, F3, F5 and F6 with horizons labelled H1, H2, H3 and H4 were mapped. Major faults F1 and F3 were identified while faults F5 and F6 were minor faults. Here, the raised fault block between fault F5 and F6 can be concluded as a horst. At the summit of the horst, there is a bright reflection of the shale body (cap rock) which can indicate the potential of hydrocarbon accumulation.

Fault F5 and F6 is a horst fault type.

Structural Interpretation

From the 6 faults mapped, different fault types were observed: Normal, Reverse, Horst, Synthetic and Antithetic.

Synthetic and antithetic faults are terms used to describe minor faults associated with a major fault. This fault type was also evident in this study. Synthetic faults dip in the same direction as the major fault while the antithetic faults dip in the opposite direction (see Figure 7). These faults may be accompanied by rollover anticlines. A rollover anticline is one of the major petroleum traps which are widely evident in the Niger Delta Structural Style. This confirms hydrocarbon accumulation in Inline 5840.

Hydrocarbon Reservoir Analysis

From Inline 5840, the hydrocarbon potential is evident by the fault type present which is the synthetic and antithetic faults which is likely to be accompanied by rollover anticlines. This fact is evident in the Niger Delta Structural Style.

From Inline 6182, the hydrocarbon potential is evident by the fault type present (horst). A horst is a raised fault block bounded by normal faults. In this study, the raised fault block between fault F5 and F6 can be concluded as a horst (see Figure 8). At the summit of the horst, there is a bright reflection of the shale body (cap rock) which can indicate the potential of hydrocarbon accumulation. This is because, in many rift basins around the world, the vast majority of discovered hydrocarbons are found in conventional traps associated with horsts. For example, much of the petroleum found in the Sirte Basin, Libya is found on large horst blocks. (Obaje, S.O. 2013)

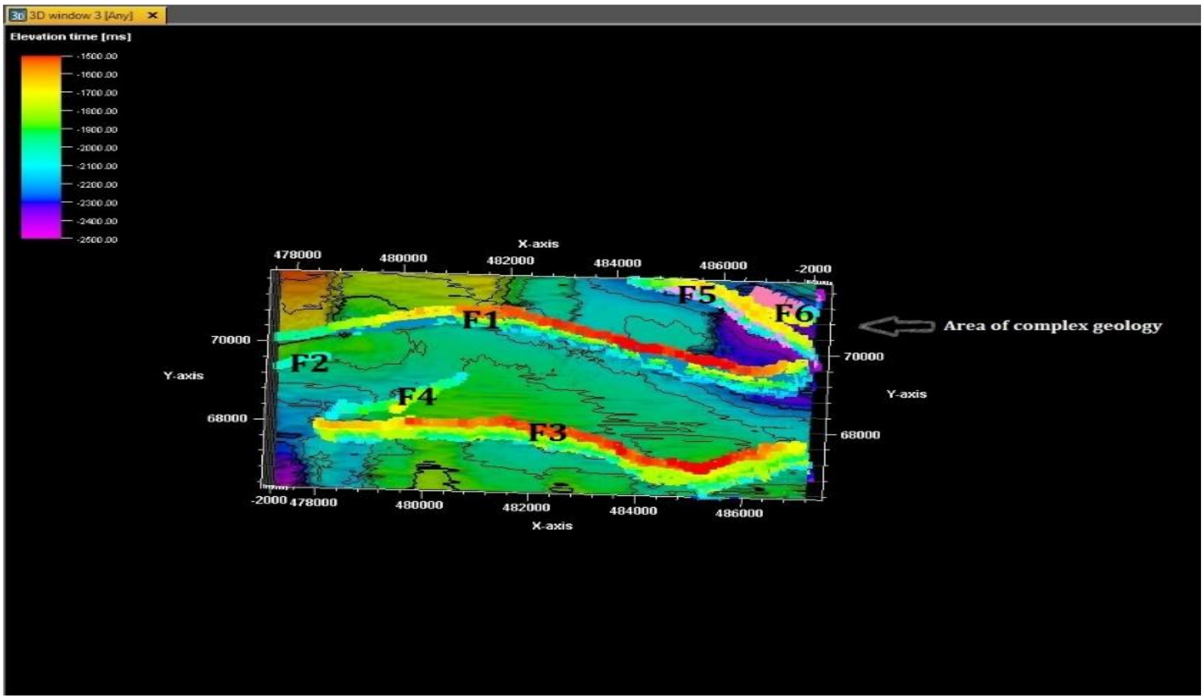

Figure 9: Seismic attribute showing area of complex geology

In the figure 9, there is a zone which is term **area of complex geology**. It is called complex geology because, in this region, faults F1 (Normal fault), F5 and F6 (Horst) converge at a particular region. The faults in this region could be structural seals for the accumulation of hydrocarbon.

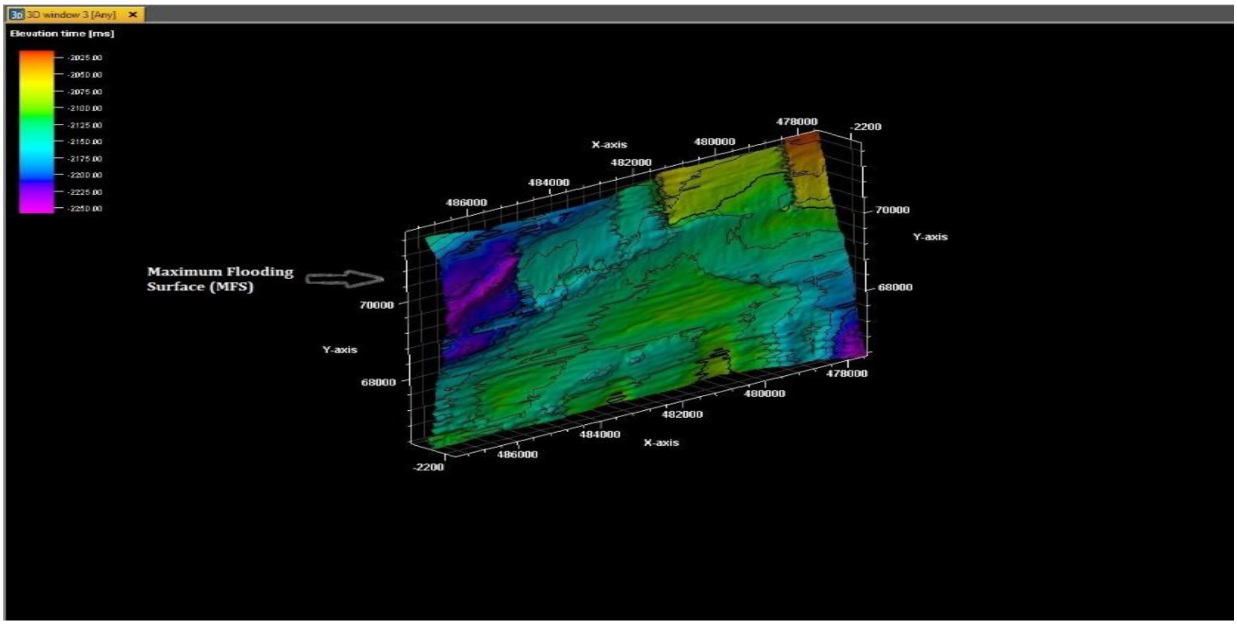

Figure 10: Seismic attribute showing the Maximum Flooding Surface of a particular horizon in the Tomboy field.

Due to increase in sea level, the sand sediments from the higher regions flooded downwards and thereby accumulating at the deepest region. The colour progression of this horizon tells it all. The MFS was caused by slow deposition of sediments.

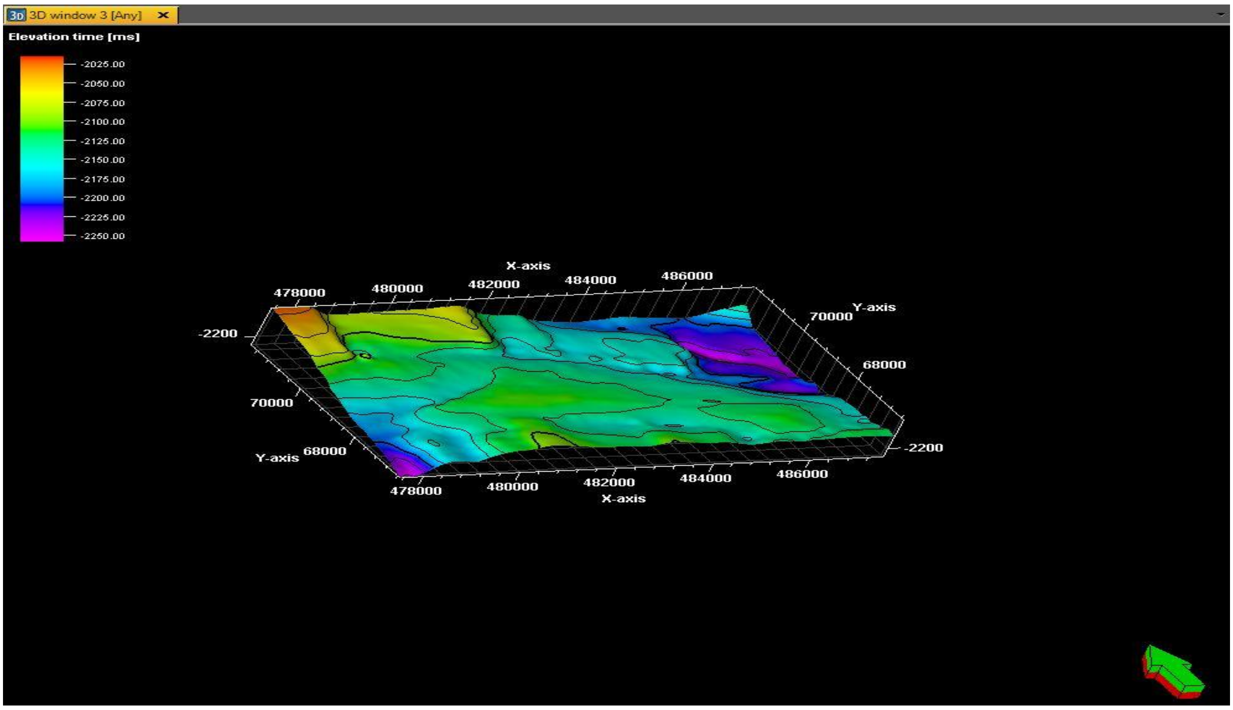

Figure 11: TWT Seismic Attribute for Horizon 1

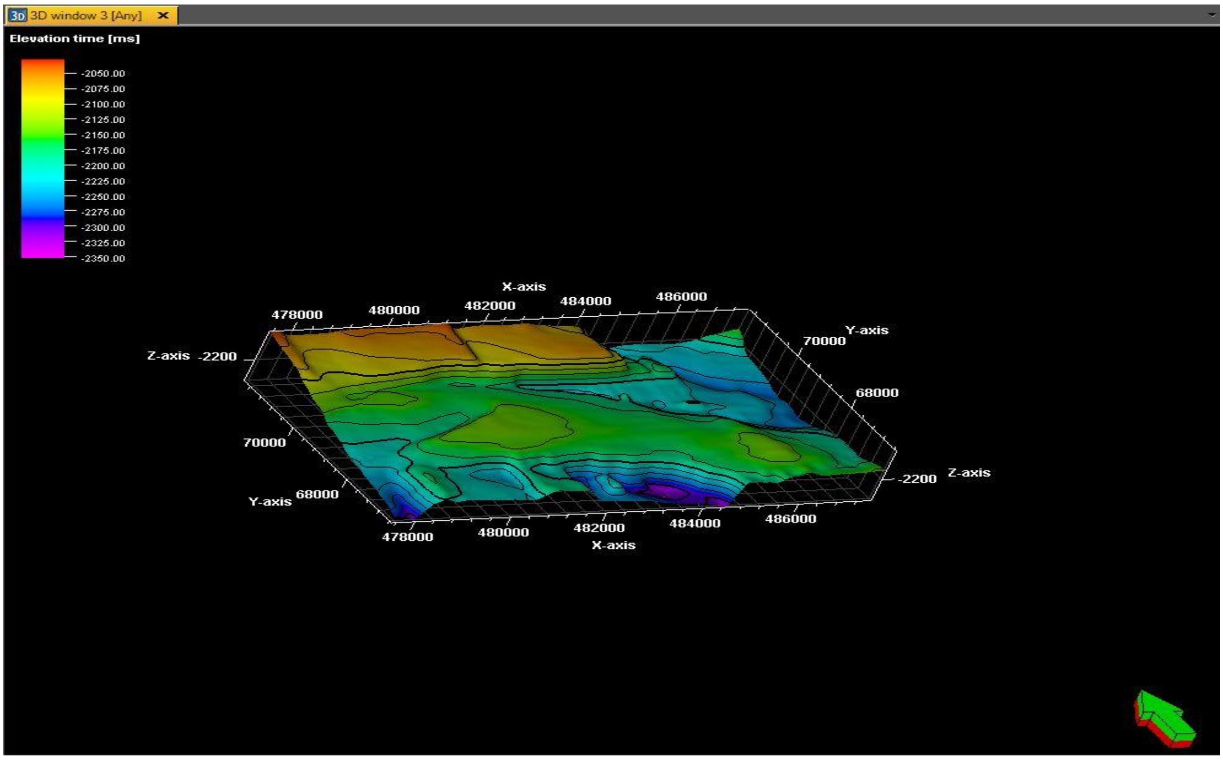

Figure 12: TWT Seismic Attribute for Horizon 2

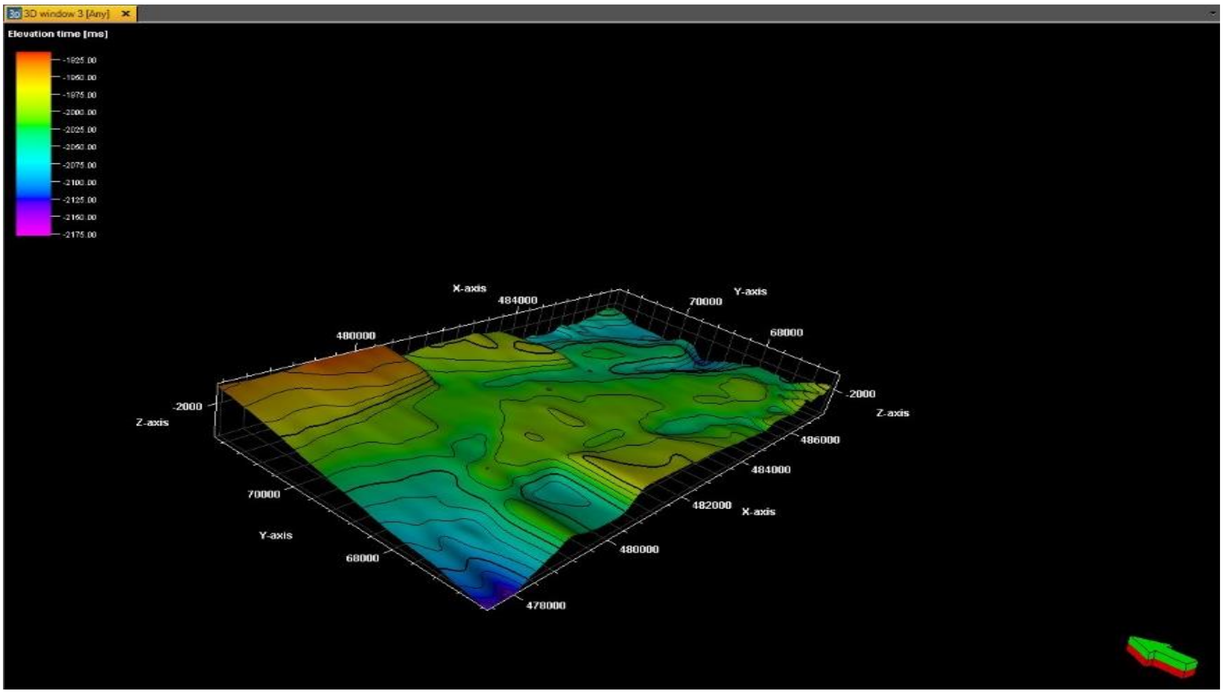

Figure 13: TWT Seismic Attribute for Horizon 3

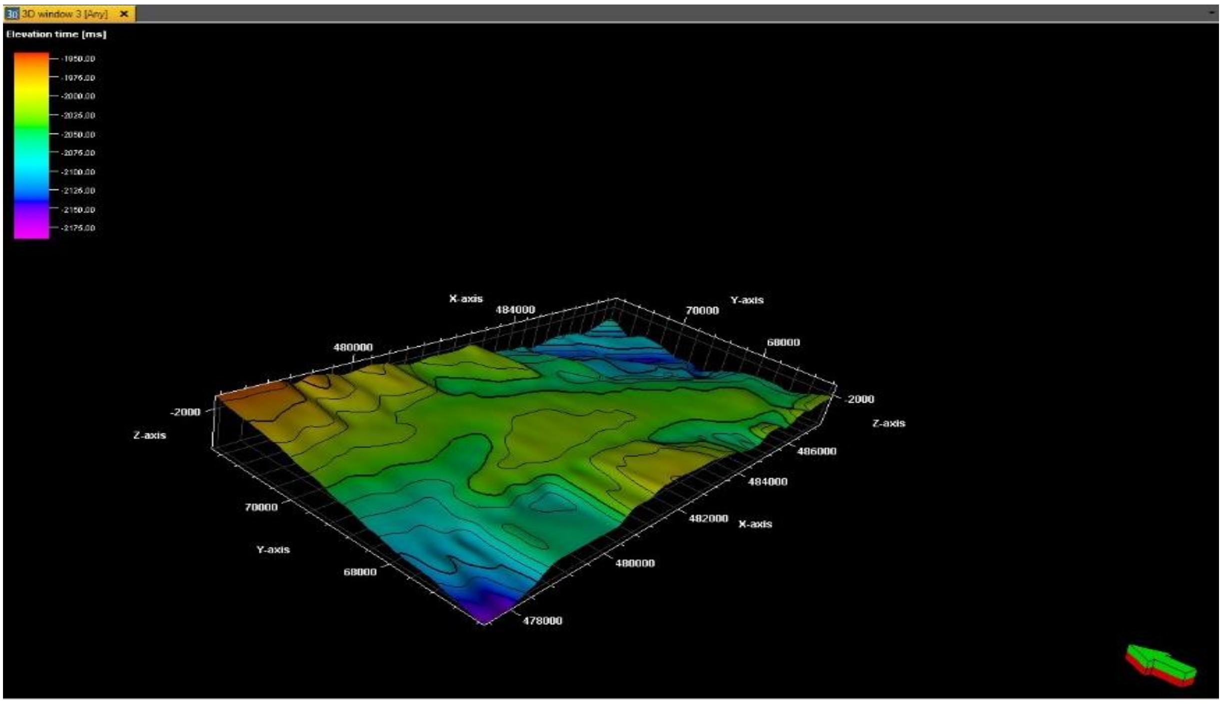

Figure 14: TWT Seismic Attribute for Horizon 4

Time attribute shows the time taken for the seismic waves to reach the rock boundary and reflect back to the receiver. Two-Way-Time (TWT) is a function of time which is affected by porosity levels of the lithology. Time levels are portrayed by the intensity of the colour. **Figure** The importance of this attribute to oil and gas exploration is that it gives a relationship between the time of travel by the seismic waves hitting

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11-14 shows the TWT attributes for Horizons 1-4 respectively.

each horizons and the porosity and liquid saturation

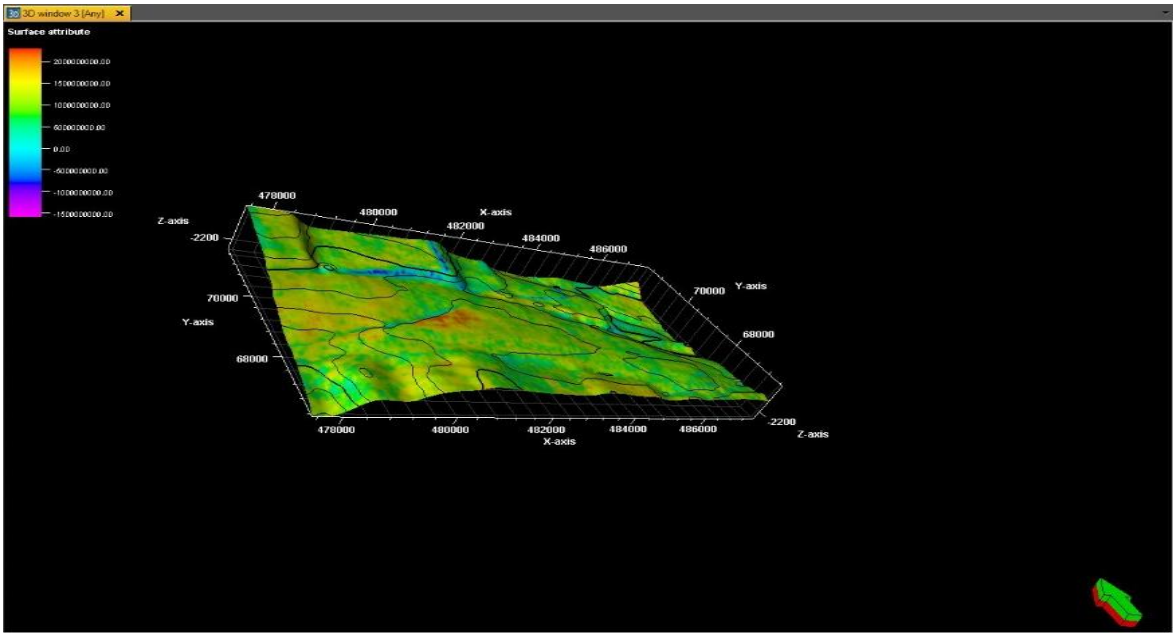

Figure 15: Maximum amplitude Seismic attribute for zone 1

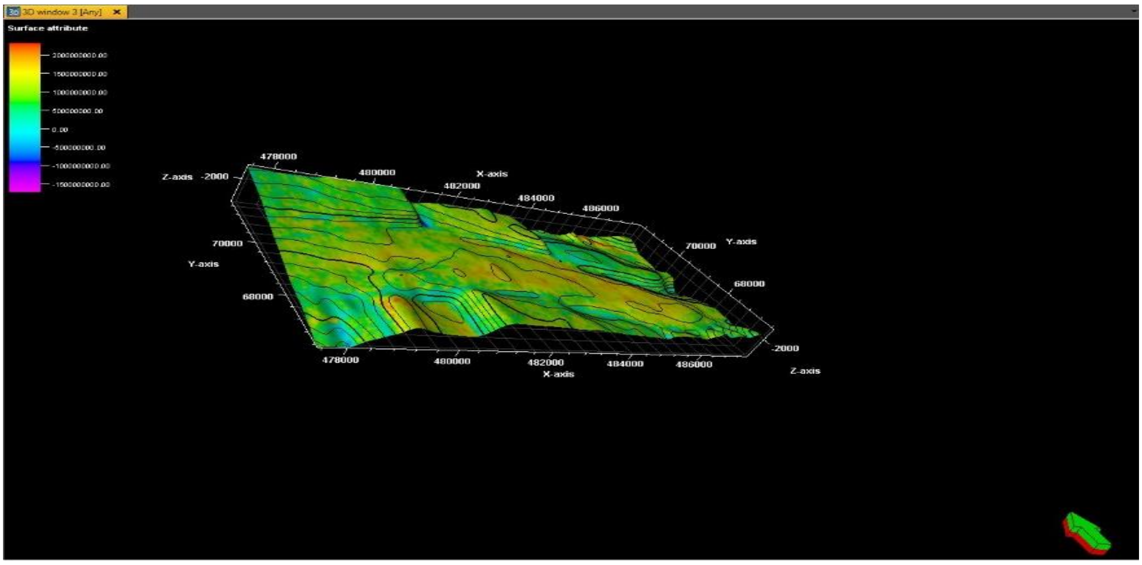

Figure 16: Maximum amplitude Seismic attribute for zone 2

For amplitude attributes, the high amplitude pattern (increased colour code) observed could indicate increase in the velocity contrast between horizons 1 and 2 respectively. **Figures 15 and 16 shows the Maximum Amplitude attributes for zone 1 and zone 2 respectively.** The importance of this attribute to oil and gas exploration is that Amplitude is often found to correlate strongly with porosity and/or liquid saturation because this reservoir properties have a strong effect on both velocity and density, seismic reflections are generated at boundaries where the acoustic impedance changes.

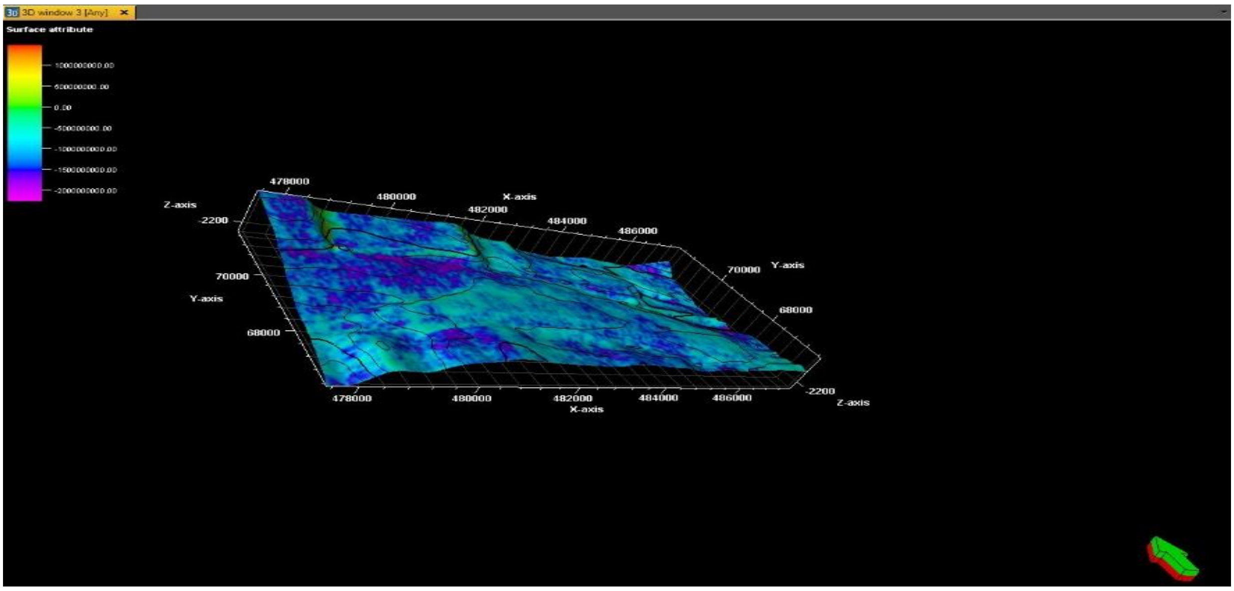

Figure 17: Minimum amplitude Seismic attribute for zone 1

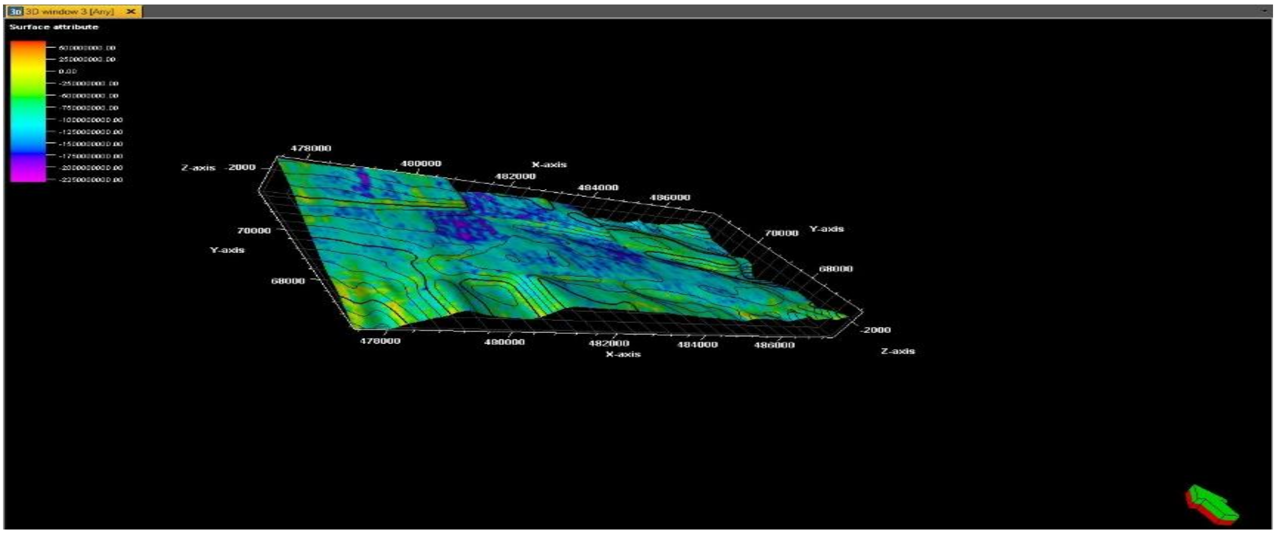

Figure 18: Minimum amplitude Seismic attribute for zone 2

For amplitude attribute, the low amplitude pattern (decreased colour code) could be a resulting effect in decrease in the velocity contrast between the horizons 1 & 2 respectively. **Figures 17 and 18 shows the Maximum Amplitude attributes for zone 1 and zone 2 respectively.**

The importance of this attribute to oil and gas exploration is that amplitude is often found to correlate strongly with porosity and/or liquid saturation because this reservoir properties have a strong effect on both velocity and density and seismic reflections are generated at boundaries where the acoustic impedance changes

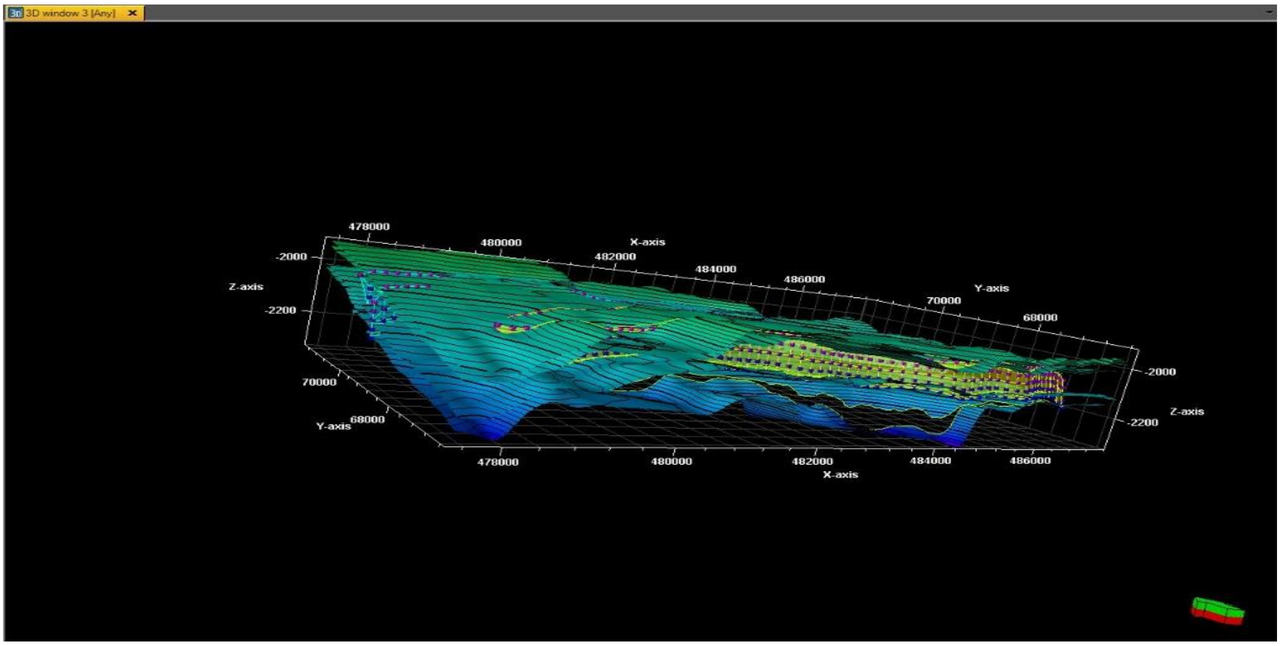

Figure 19: Corner point grid with 6 faults and 4 horizons (Front View)

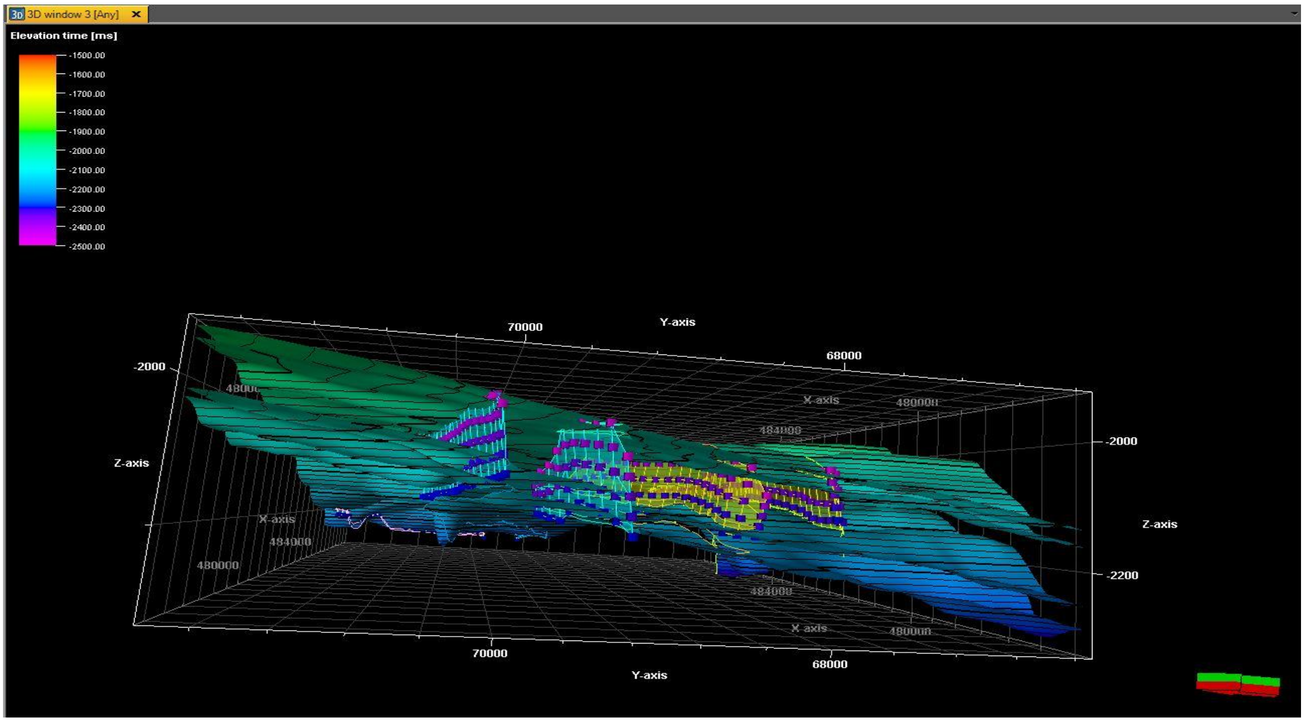

Figure 20: Corner point grid with 6 faults and 4 horizons (Side View)

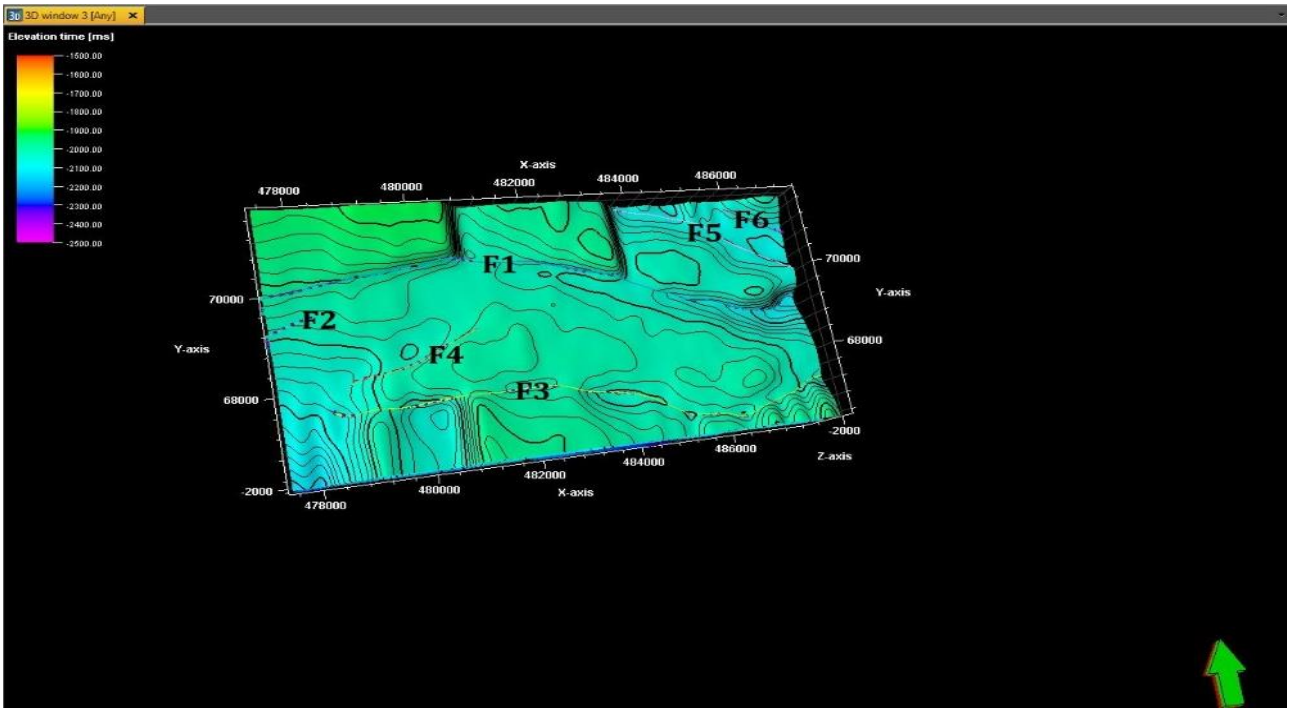

Figure 21: Corner point grid with 6 faults and 4 horizons (Top View)

The 6 faults and 4 horizons were modelled. These are regarded as structural modelling of the reservoir. The faults were vertically truncated from the top of the 4 horizons to the base. The fault modelling was done via corner point gridding and they were modelled to create structurally correct fault representations within horizons H1, H2, H3 and H4. **Figures 19, 20 and 21 shows the FRONT, SIDE and TOP views of the 3D models respectively.** The 3-D models shows an overview of the faults and horizons without showing the attribute effects on each horizons.

Conclusion

The Tomboy field is highly faulted which indicates huge hydrocarbon potential of the field. The trap mechanism observed is structural trap which all but confirms the hydrocarbon potential of the field.

The three (3) correlated wells showed continuity in the lithology (sand sediments) of the field. The sand sediments were medium to well sorted.

From the synthetic seismogram of the well-seismic tie, the field of study is of deep marine depositional environment. There is a huge effect of porosity on amplitude changes between sand and shale. The negative amplitude indicates Sand while the positive amplitude indicates Shale.

Seismic attributes have been able to identify area of complex geology and the Maximum Flooding Surface of the sediments' deposition.

3D models of the seismic attributes revealed the Maximum Flooding Surface and Area of Complex Geology.

Recommendation

I strongly recommend that more wells should be drilled in **areas of complex geology** where multiple faults are present. These faults could serve as structural traps (seal) for hydrocarbon accumulation. These wells should be drilled deeper than existing depths.

Acknowledgement

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