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Using Seismic and Wireline Log Data For Integrated Hydrocarbon Potential Evaluation In Offshore South Tano Basin (Eastern Extension of the Ivory Coast Basin)

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Abstract: *Rocks inthe southern part of the offshore Tano Basin Ghanaare made up of the Apollonian series, with reservoirs structurally controlled in some places. Past studies in the basin gave an indication of oil and gas of considerable economic importance. The main objective of this study was to evaluate the petroleum potential of the South Tano field by finding new reservoir zones which have not yet been established due to inappropriate data analysis. This was done by processing old data from this area using the Petrel 2013 software. A combination of results using petrophysical, volumetric, seismic interpretation, and modelling, showed that the central part of the study area reveals a four-way dip closure anticline in the Intra Upper Albian Formation (IUAF), and is bounded by three distinct normal faults. Oil-water and gas-oil contactswere identified in sands of the IUAF at depths of 19234m and 1828m respectively. Volumes calculated in the reservoir sands gave a STOOIIP of 1247x10^6million barrels(bbl) and GIIP of 41x10^6standard cubic meter (sm^3) respectively.Previous work done in the South Tano field gave indication of oil and gas shows ofconsiderable economic relevance.*

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I. Introduction

Hydrocarbon potential evaluation requires a model capable of realistically predicting the dynamic behaviour of oil and gas fields in terms of fluid recovery and production rate for different operating conditions (Jahn*et al.*, 2008). Three-dimensional (3D) numerical earth models play an increasingly central role in the exploration and production of hydrocarbons. One of the main goals of hydrocarbon potential evaluation is to describe the complexity and heterogeneity of the reservoir (Grana *et al.*, 2010). Reservoir evaluation is routinely used to plan new wells, calculate hydrocarbon reserves, and when coupled to a flow simulator, predict production profiles. An integrated hydrocarbon potential evaluation must therefore include the quantitative integration of seismic and well data to obtain a more accurate representation of the reservoir properties (Ndip *et al.*, 2018).

Offshore South Tano Basin has been declared sub-commercial for petroleum exploitation (Moshin, 2012) because no detailed knowledge exist on the reservoir characteristics as well as thepetrophysical properties of the reservoirs rocks. This research seeks to reprocess and interpret available data sets to establish the existence of economically producible hydrocarbon reserves (oil and gas) in the basin by finding new potential reservoir zones which hitherto were not seen, due to lack of state of the art hydrocarbon exploration techniques.Therefore this study aimed at delineating the hydrocarbon bearing zones and calculated their petrphyscial properties, the stock tank oil initially in place(STOIIP),and gas initially in place (GIIP) in the reservoirs zones. , This was done by performingseismic to well tie in order to identify and determine thicknesses of hydrocarbon pay zones, and possibly suggest best locations for drilling.

II. Location Of Study Area

The study area is located on the south-western flask of the offshore Tano Basin, which is the eastern extension of the Ivory Coast Basin, (Fig.1). The area lies in the ocean waters of the Gulf of Guinea off the coast of Cape Three Point in the western region of Ghana. The basin is part of the coastal sedimentary basin extending along the West African coast which include the Ivory Coast Basin, Central Basin and Benin embayment. The portion of the basin in Ghana can be found between the Tano River in the west and the Ankobra River in the East (Derigubaa, 2012).

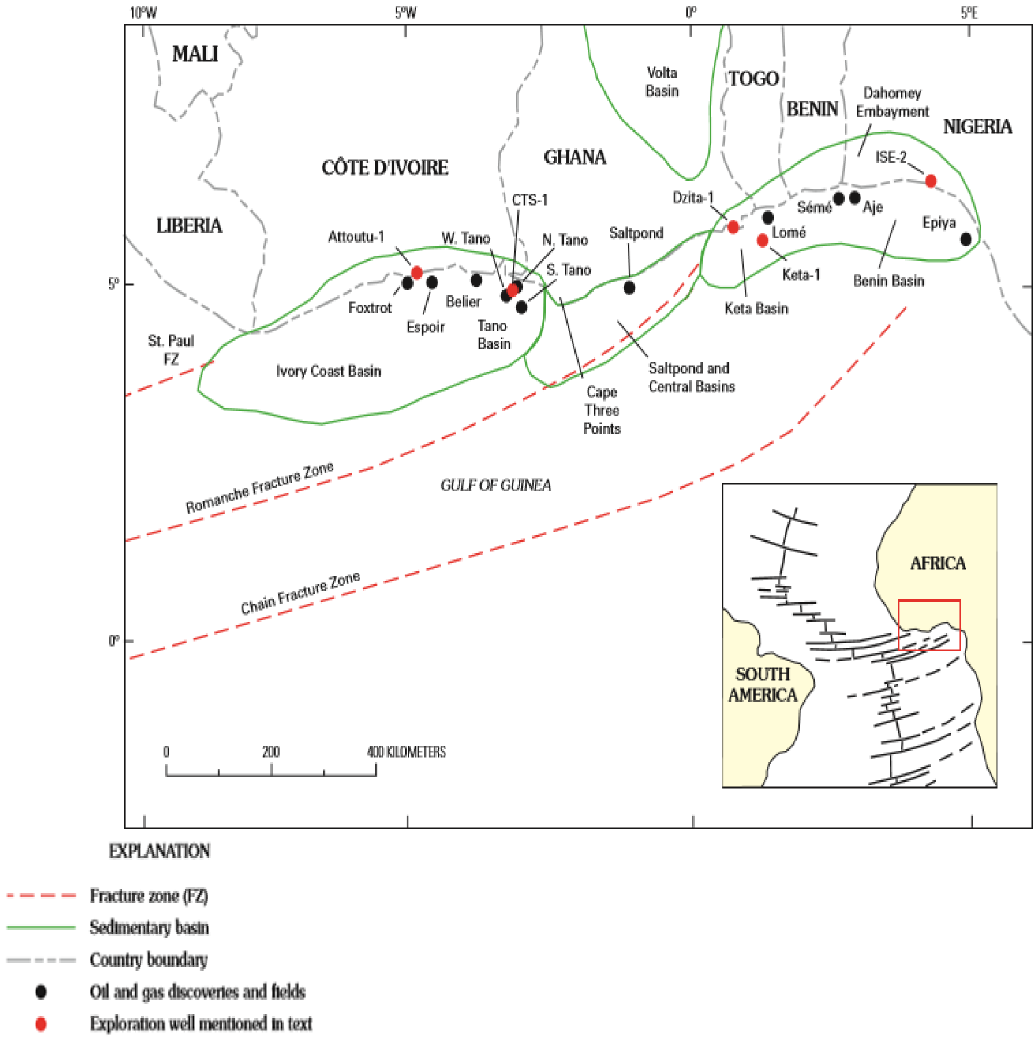

Fig.1: Location map of Off-Shore Tano Basin with study area indicated in red box (modified after Browns and Charpentier, 2006).

III. Geological Background And Samples

The Tano **B**asinsshare common structural and stratigraphic characteristics with other basins in Ivory Coast, Saltpond, Central, Keta, and Benin Basins and the Dahomey Embayment in that they are wrench-modified basins (Clifford, 1986) and contain rocks ranging in age from Ordovician to Holocene (Kjemperud *et al.*, 1992). They were therefore grouped together as one province. The eastern boundary is the Niger Delta Province (Klett *et al.*, 1997), and the western boundary is the West African Coastal Province (Fig.2).

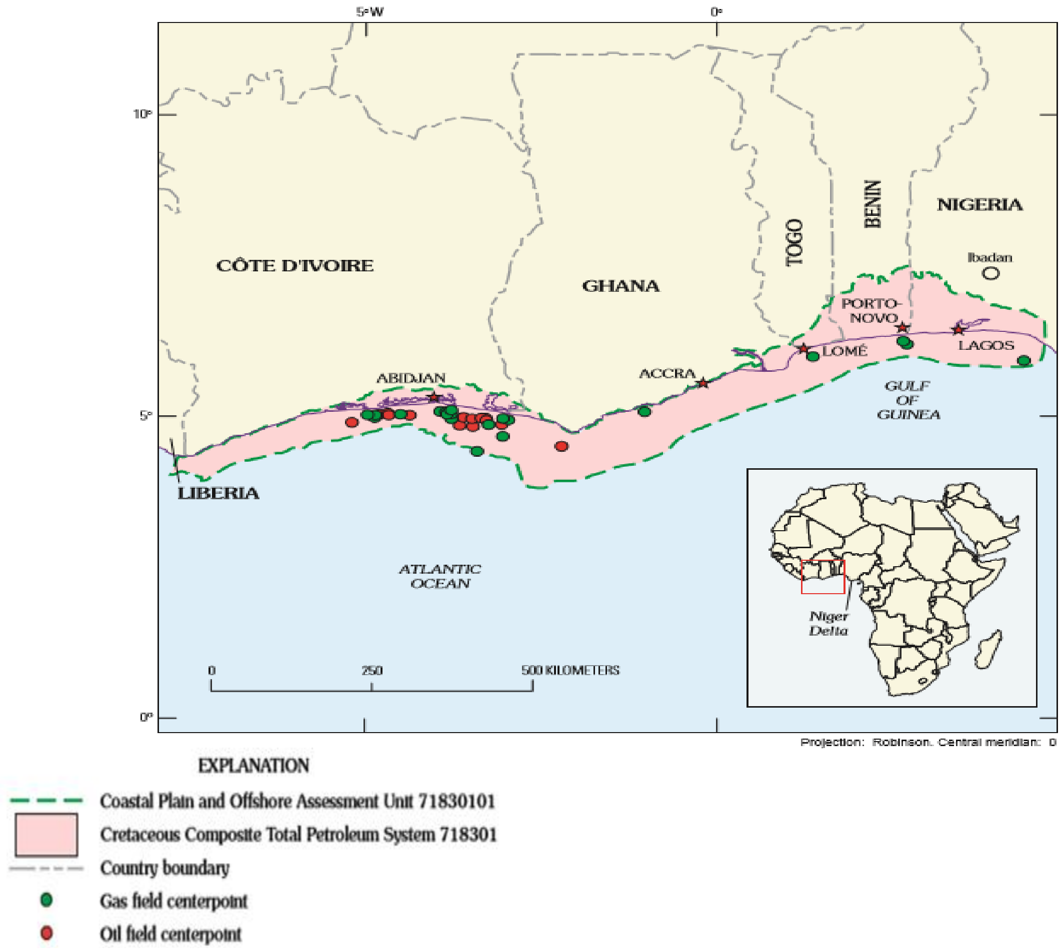

Fig. 2: Map Showing the West African Coastal Province, Gulf of Guinea Province and the Niger Delta Province (after Petroconsultants, 1996).

The Tano Basin resides on a transform margin, between the Romanche and St Paul transform faults and is the eastern extension of the Cote d'Ivoire-Ghana Basin.Itformed because of trans-tensional movements during the separation of Africa and South America (Fig .3), and opening of the Atlantic in the Albian (Adda, 2013).

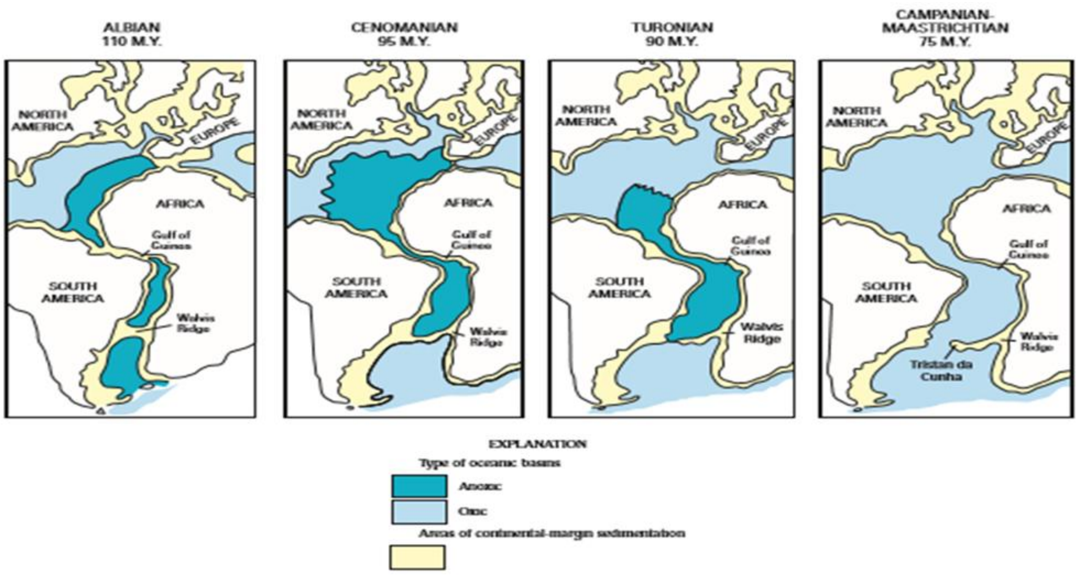

Fig. 3: Paleo- Geographic Stage in the Separation of Africa and South America during the Cretaceous (after Tissot *et al*, 1980).

The Tano Basin forms part of the broad Apollonian Formation. This Formation comprises of rocks whose ages rangefrom Cretaceous to Eocene. They consist of alternating sands, clay and limestones overlying Birimian basement rocks. The oldest rocks in the Formation are grayish green sandy shales which areAptian and the youngest members comprise recent sand and shaly clay deposits (Table 1). The Nauli limestone is highly fossiliferous (Kesse, 1985).

Table 1: Stratigraphic Table of Rocks Units in the Apollonian Formation of the Tano Basin (Kesse, 1985).

UNITS	LITHOLOGY	THICKNESS (m)	AGES
1	Loose sand, clay and shaly clay	100-215	Recent
	UNCONFORMITY		
2	Fossiliferous limestone and black clay	45-120	Maastrichtian
3	Sandstone, minor shale and limestone	610-915	Campanian
4	Conglomerates	23-76	Campanian
	UNCONFORMITY		
5	Green-gray sandstone and minor shale	300-325	Albian
6	Black Carbonaceous shale	100-450	Albian
	UNCONFORMITY		
7	Siltstone, igneous and metamorphic rock pebbles	225	Aptian
8	**Greyish green Sandstone and shale**	>200	Aptian

IV. Methodology

4.1 Data availability

The study was initiated with the collection a 3-D seismic volume (GNPC_SOUTH TANO 3D.SGY) and well data of two wells (well 1X-1S and well 1X-2S) from offshore Tano Basin by Ghana National Petroleum Cooperation (GNPC) .

4.2 Methods

Intergarted commercial Slumberger Petrel 2013 version was used for this study. The seismic sectionswere usedfor building the 3D geostatic models while the well data were used in evaluating the petrophysical properties of the reservoirs zones. The work flow is discussed below.

4.2.1*Loading of Well Data*

Well header for the two wells was uploaded and displayed in a 3D window followed by well logs data and finally well tops data.Correlation was done between wells using well tops which are essentially Formation tops (Fig.4). The data sets depict the chronostratigraphy of the Formation as well as the upper boundary of each Formation encountered in the well.Various well logs (Gamma ray log, Resistivity logs, Neutron log, Density log, Caliper log and Sonic log) where then loaded into the petrel software), before the identification of seismic volumes and processed volumes began.

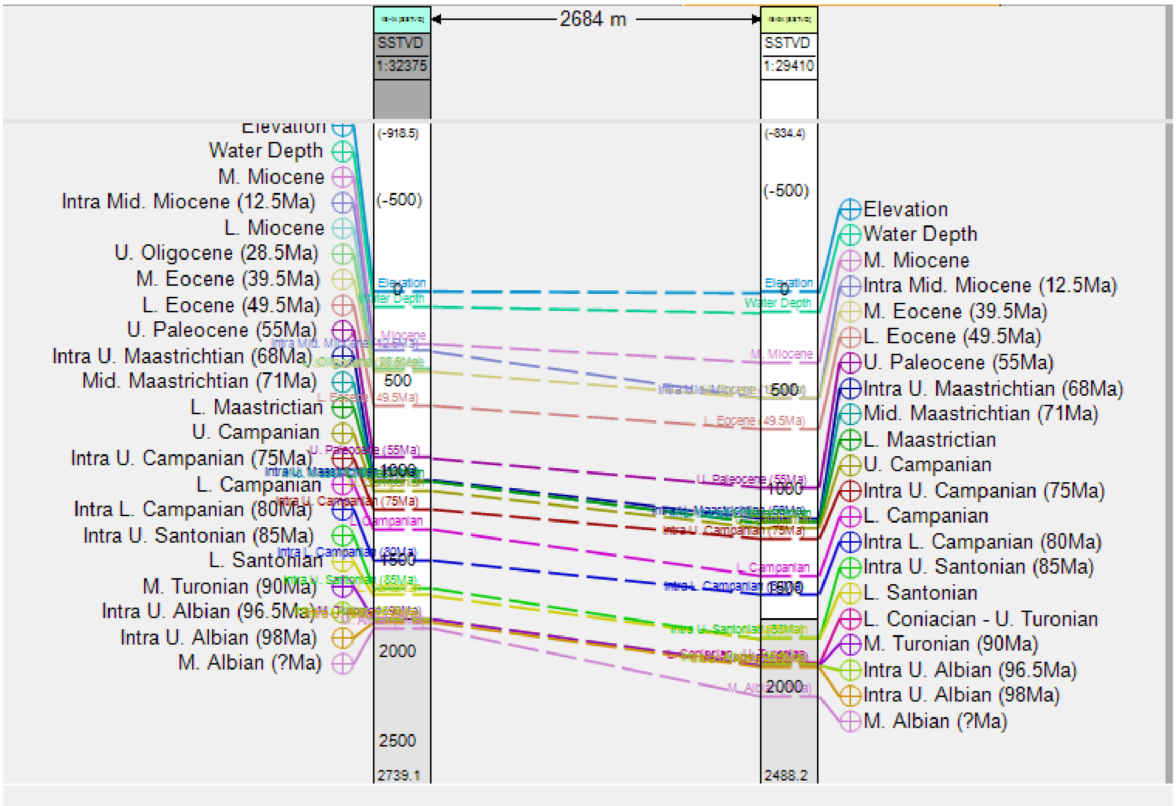

Fig.4: Well Section window displaying well tops of both wells

Creation of Facies Log Using Petrel Calculator

The Gamma ray log and an algorithm (MY_FaciesGR1=If (GR<75, 0, 1) was used to differentiate between the sand and shale. The facies template under the discrete petrophysical property was modified to create the facies logs.

The check shot data was used to help establish communication between the well and seismic data. A one-way time wascreated and a plot between the depth (Z) and two-way time (TWT) showed a straight line (Fig.5).

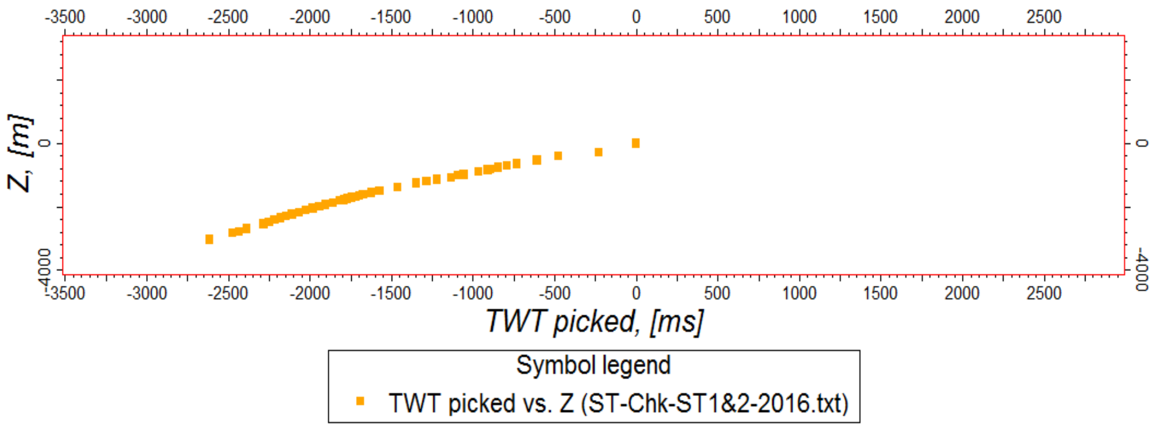

Fig .5: Graph of TWT Picked Versus Z (Check shot) Used for Quality Check on the Check Shots.

Depth conversion was done using Look up Fucntion .This serves as the bridge between seismic and well data. A velocity lookup function was generated to convert surfaces created and faults interpreted from time to depth and to adjust the sonic log according to seismic measurements in the borehole.

For horizon mapping and seismic-to-well-tie, gamma ray logs and resistivity logs were chosen for the identification of mapping horizons. The identified horizons were further quality-controlled by producing and using a facies log. This was followed by plotting of identified reservoir zones from well log to the seismic in the interpretation window (Fig. 6)

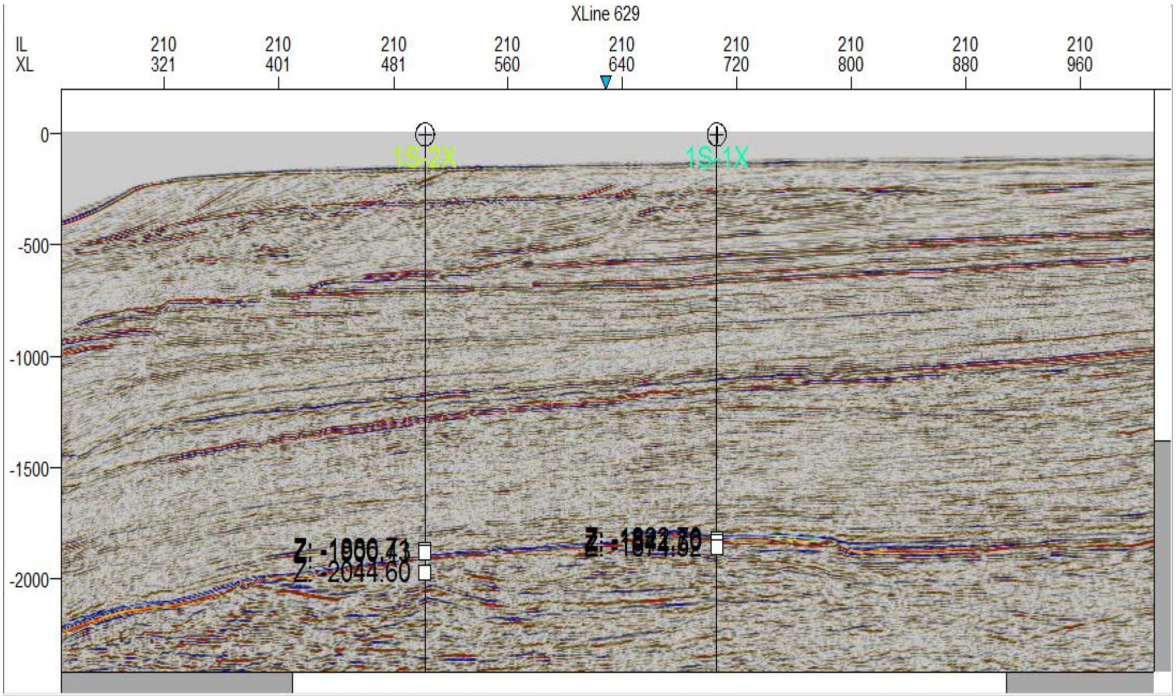

Fig. 6: Horizon mapping and seismic well tie.

Faults were interpreted or picked on the seismics when there is a break in the horizon and there has been displacement on the horizon using the fault interpretation tool in the software. These faults were picked within the interpreted horizon where the reservoir zone (Fig. 7).

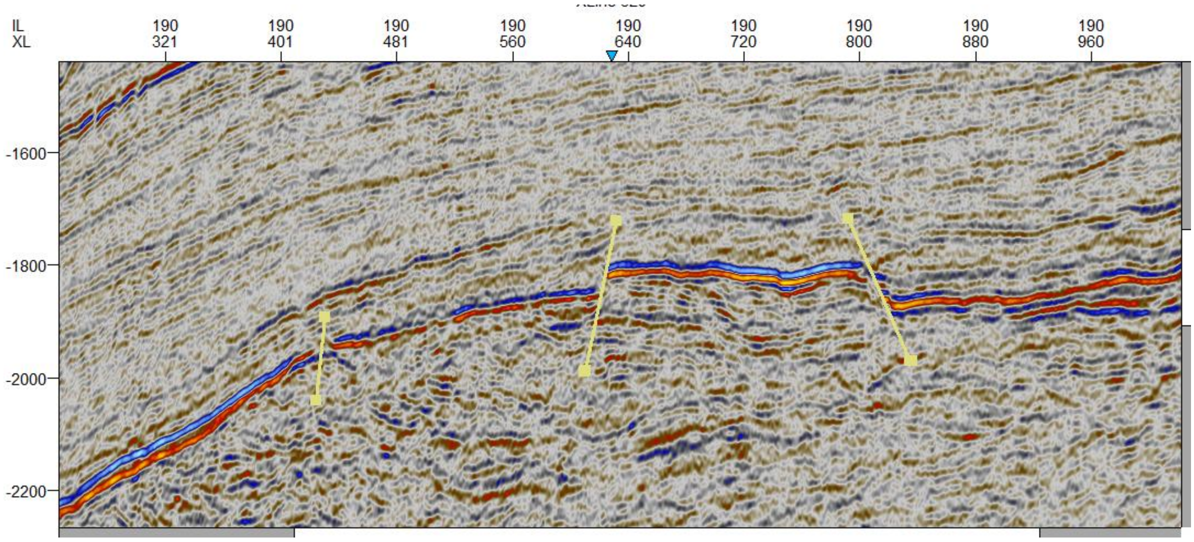

Fig.7: Seismic section with fault interpretation.

The horizon interpretation was done on the best seismic to well tie. Interpretation of the prospective horizons was done at an interval of ten traces in both inline and cross line. Seeded 2-D auto tracking, guided 2-D tracking and manual interpretation was used to pick the horizons cite ref (Fig.8).

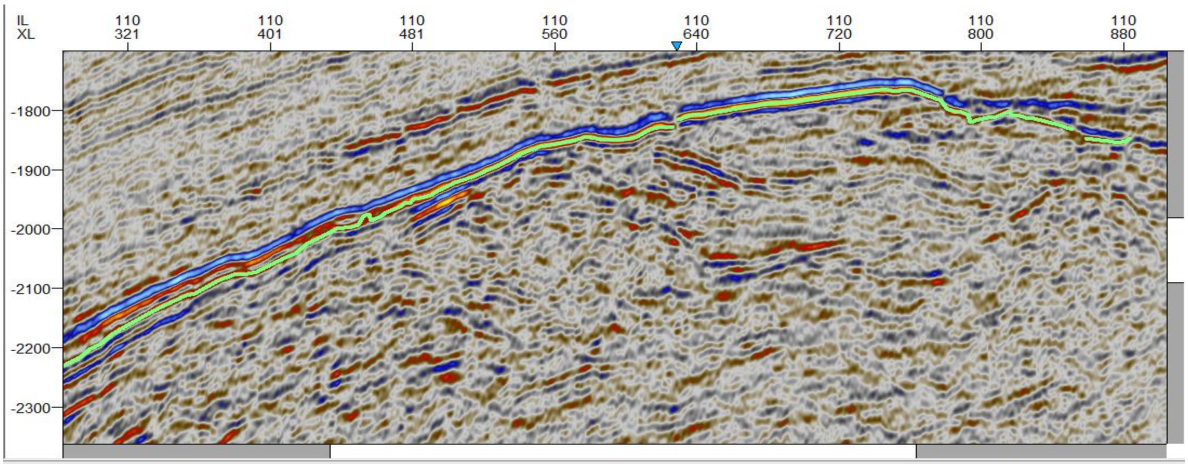

Fig.8: Seismic section with horizon interpretation

Time and Depth structural maps were generated from the top horizon and the bottom horizons through Make/Edit surfaces under utility in the process pane.

A seismic attribute map was generated to enable us see different aspects of the lithology (sand or shale), depositional environment, structure and stratigraphy. The Attribute used was the Root Mean Square (RMS) which is a sand identifier. High RMS values represent sand.

Boundary polygons were created around the zone of interest for P90 (most volume that can be recovered), P50 (average volume) and P10 (worst case scenario) and volume calculation was done between the top surface and bottom surface.

4.2.3Petrophysical Parameters

Petrophysical parameters used to evaluate the reservoir prosperity include porosity, hydrocarbon saturation and volume of shale.

Rock porosity was obtained from the sonic log, density and neutron logs using the equation below:

$$\emptyset = \frac{(\rho ma - \rho b)}{\rho ma - \rho fl}$$

$\emptyset = (\rho ma - \rho b)/(\rho ma - \rho fl)$

Where

$\emptyset = porosity$,

ρma (matrix density) = 2.65 gm/cm^3 (for sandstone),

ρfl is the fluid density= 1 gm/cm^3,

ρb = formation bulk density.

The criteria for classifying porosity are :(Glasbey, 1991)

$\emptyset < 0.05$ = Negligible

$0.05 < \emptyset < 0.1$ = poor

$0.1\ \emptyset < 0.15$ = fair

$0.15 < \emptyset < 0.25$ = good

$0.25 < \emptyset < 0.30$ = very good

$\emptyset > 0.30$ = excellent.

4.2.4Volume of Shale

The volume of shale (Vsh) in the reservoir zone was determined using gamma ray (GR) logs. This was done by reading the GR value at zones where the GR indicates to be clean, porous sand and where these signatures also indicate as pure shale. The readings for the zones of interest are put into the formula below: (E.R. Crain, 1986).

$I_{GR} = (GR_{log} - GR_{min})/(GR_{max} - GR_{min})$

Where, GR_{log} = GR reading of formation

GR_{min} = minimum GR reading (clean sand or carbonates)

GR_{max} = maximum GR (shale base line value)

The volume of shale is then determined using the Lavrionov (1969) equation

Vsh= 0.083($2^{3.7IGR}$_1.0)

4.2.5Water Saturation Determination

The resistivity log was used to differentiate between Formation water and possible hydrocarbon. The resistivity of a formation is a very good indicator of the type of fluid present in the pore space of it (Reservoir Characterization and modelling lecture notes university of Ghana).
Water saturation determinations from resistivity logs werebased on Achie's (1952) equation.
Sw = [(a /Φm) *(Rw / Rt)] (1/n)

Sw: =water saturation
Φ= porosity
Rw=formation water resistivity
Rt: =true resistivity
a= constant (often taken to be 1)
m= cementation factor (varies around 2)
n= saturation exponent (generally 2)

4.3Modelling

3-D Geostatisticalmodelswerebuild using the horizon and faults interpreted from the 3-D seismic volume from the south Tano field. Simple gridding, corner point gridding and structural framework methods were used in the modelling.

V. Results And Interpretation

5.1 Identification and processing of seismic volumes

High seismic zones wereclearly identified from both the in-line and cross-line survey from the realized seismic volumes

Three horizons were identified within the reservoir zone and include; Mid Turonian Upper Albian (96.5Ma), Upper Albian (96 Ma) to Intra Upper Albian (98Ma), and Intra Upper Albian (98Ma).

The seismic horizons identified from the 1S-1X well was correlated with well 1S-2X as well as for the interpretation of the horizons as shown below (Fig.9).

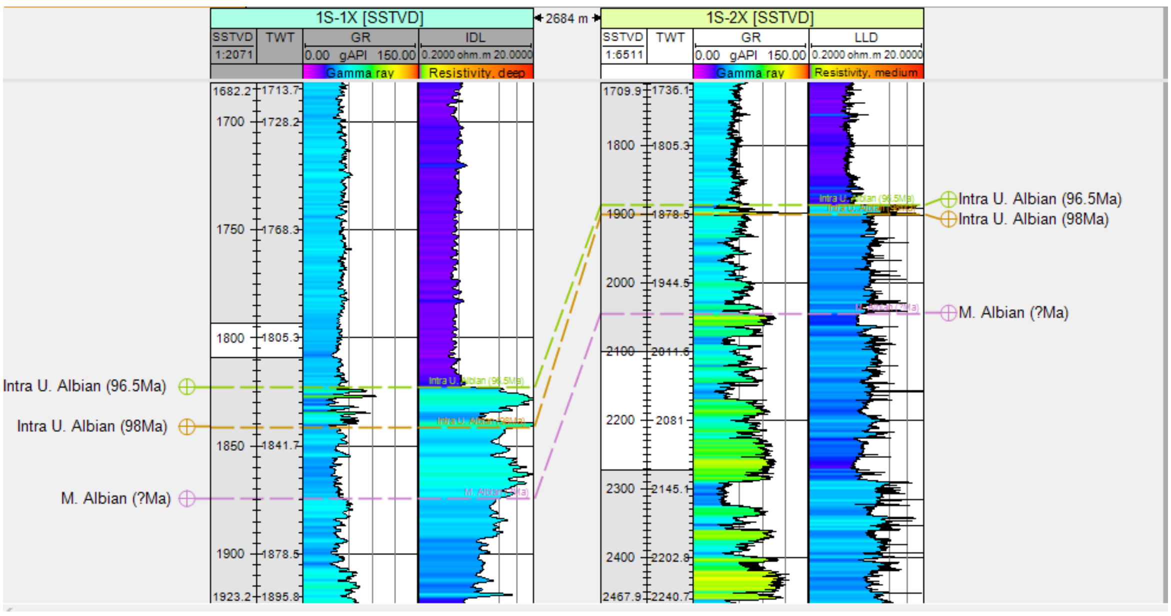

Fig.9: Correlation between 1S-1X and 1S-2X showing the reservoir zone

Facies logs were generated to confirm the delineated reservoir zones mapped and modelled showing the presence of sand and shale facies. Density and neutron logs were used to determine the net reservoir zone showing crossovers indicating the presence of gas and oil in the reservoir as well as fluid contacts that exiting within the reservoir as shown in (Fig.10).

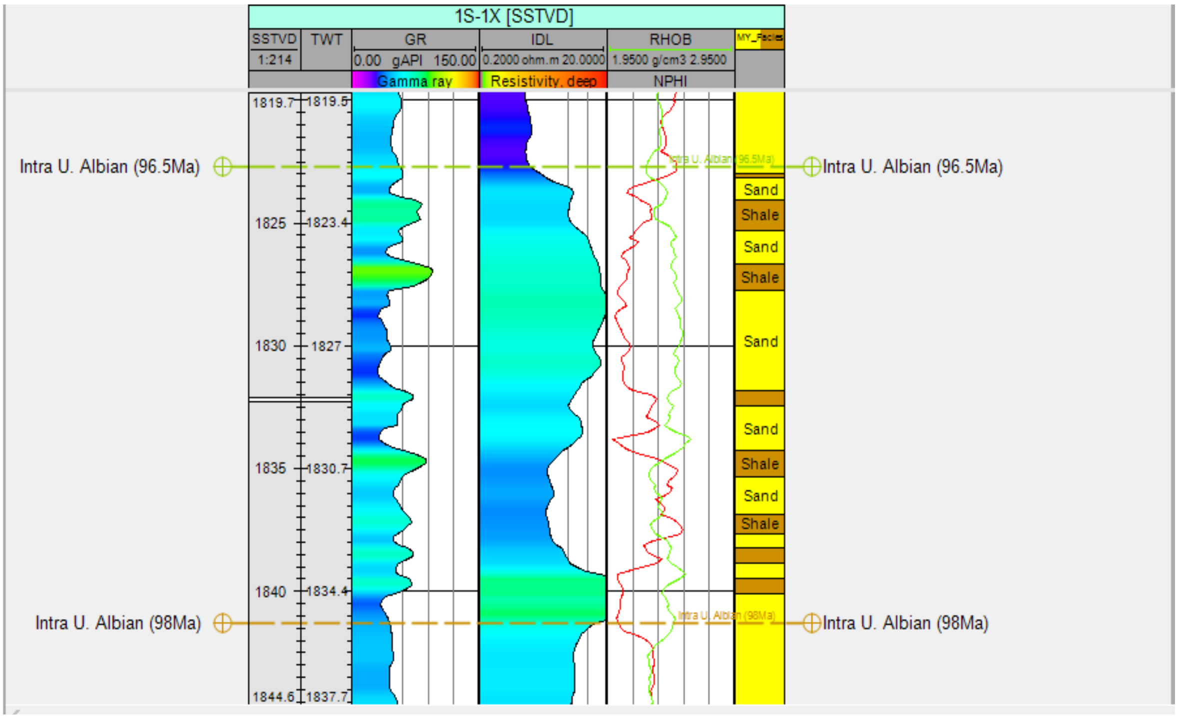

Fig. 10: Facies log, resistivity log and neutron-density log in the reservoir zone

Seismic to well tie was done as describe above and the results is shown is below Fig (13).

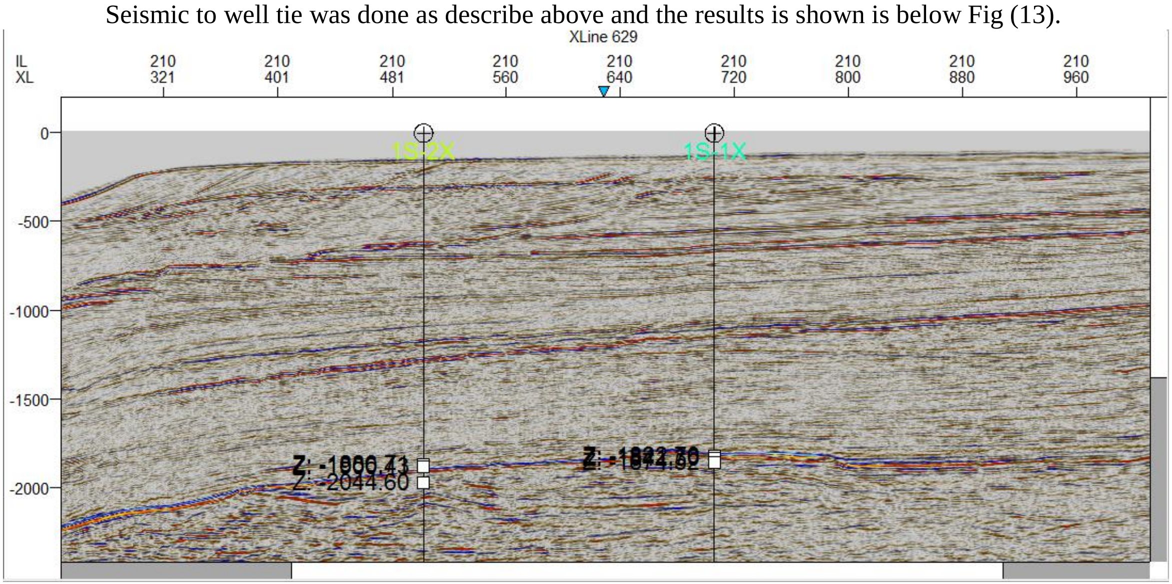

Fig.11: Seismic to Well Tie in Petrel Interpretation Window.

5.2 Horizon interpretation

Horizon interpretation was done at every ten trace for both inline and cross line. Seismic horizon was created for the Mid Turonian-Intra Upper Albian (96.5Ma) and Intra Upper Albian (98Ma)- Mid Albian seismic horizons. Surface maps were then created using this interpreted horizon to show potential hydrocarbon zones (Fig.12 and Fig 13)

Time-Depth Conversion

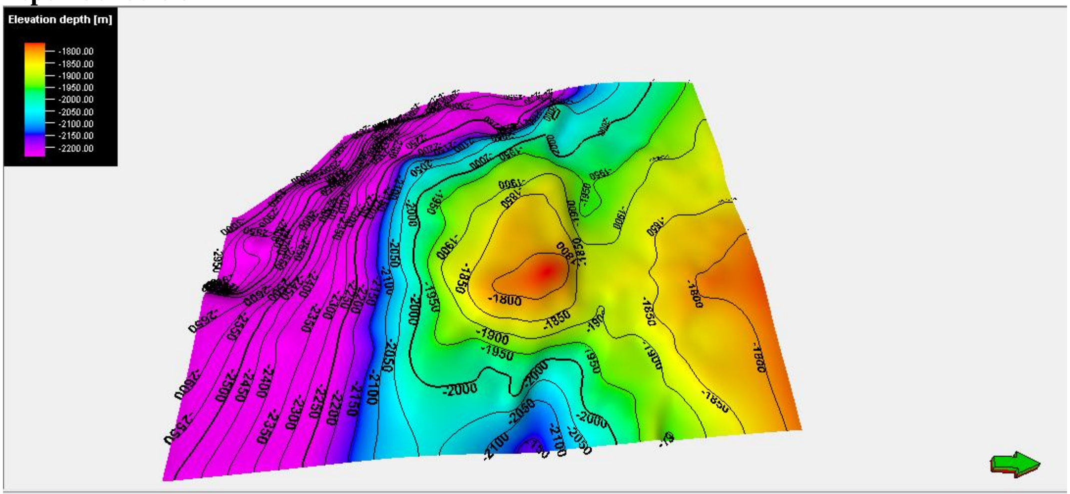

Fig12: 3D display of depth structural map for Mid Turonian-Intra Upper Albian (96.5Ma).

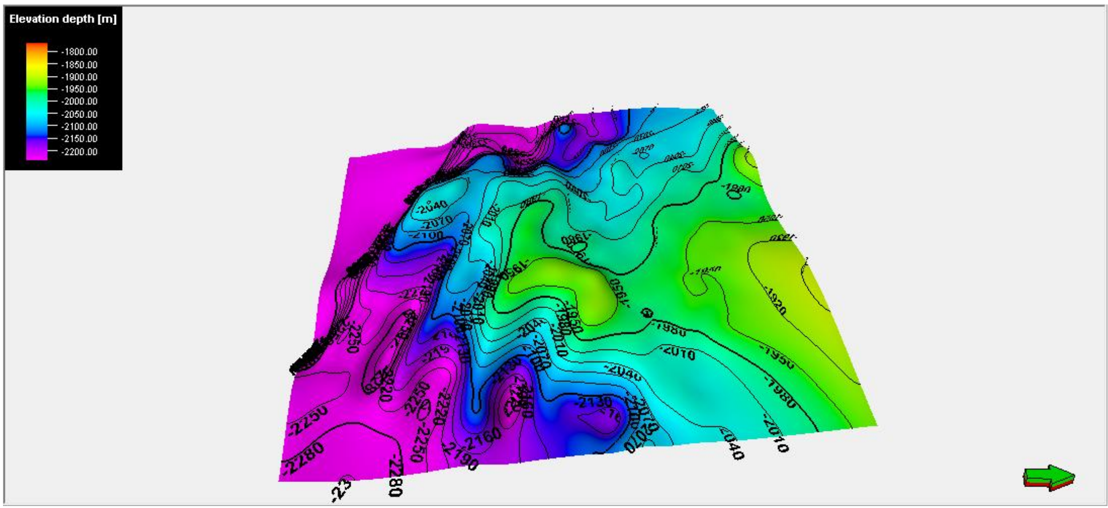

Fig.13: 3D display of depth structural map for intra Upper Albian (98Ma)-Mid Albian.

5.3 Seismic attribute generation

Seismic attributeswere carried out to know the distribution of various facies within the reservoir. This attributes give the ratio of sand within the reservoir. High RMS values represent more sand in our reservoir zone (Fig. 14)

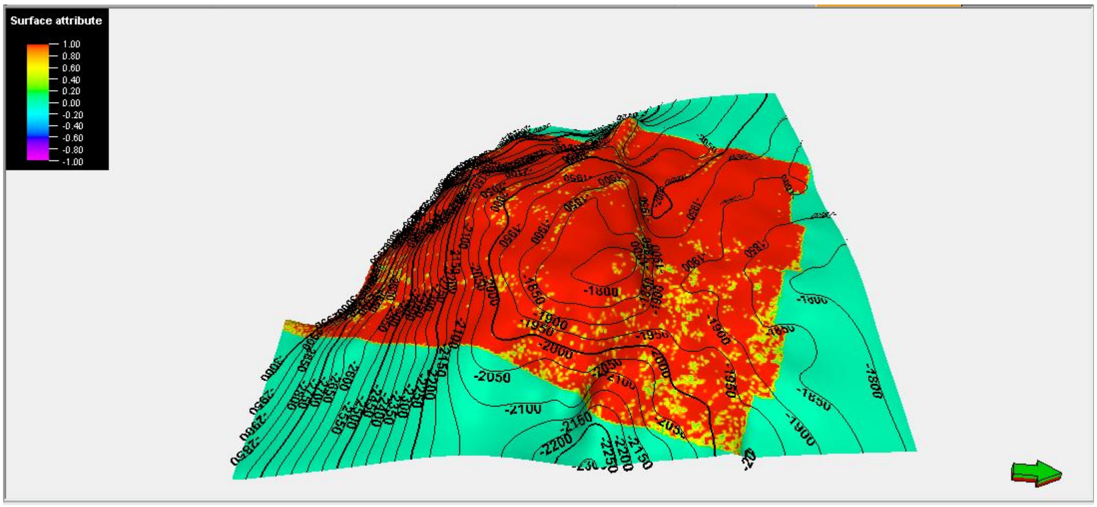

Fig. 14:3D Surface Attribute Map in depth.

5.4 Fault modelling

Modelled faults were interpreted from seismic volume in both in-line and cross-line directed to get the 3D architecture or faults framework in the study area (Fig.15).The modelled faults where the faults close or that passed through the interpreted horizons. Three fault trends of interest were modelled from the interpreted faults. Depth-converted faults were then pillar gridded and 3D remodelled. This is the first step of reservoir modelling. After which corner point gridding was carried out whichmakes use of the fault model and pillar gridding process to create a skeleton framework (Fig.15).

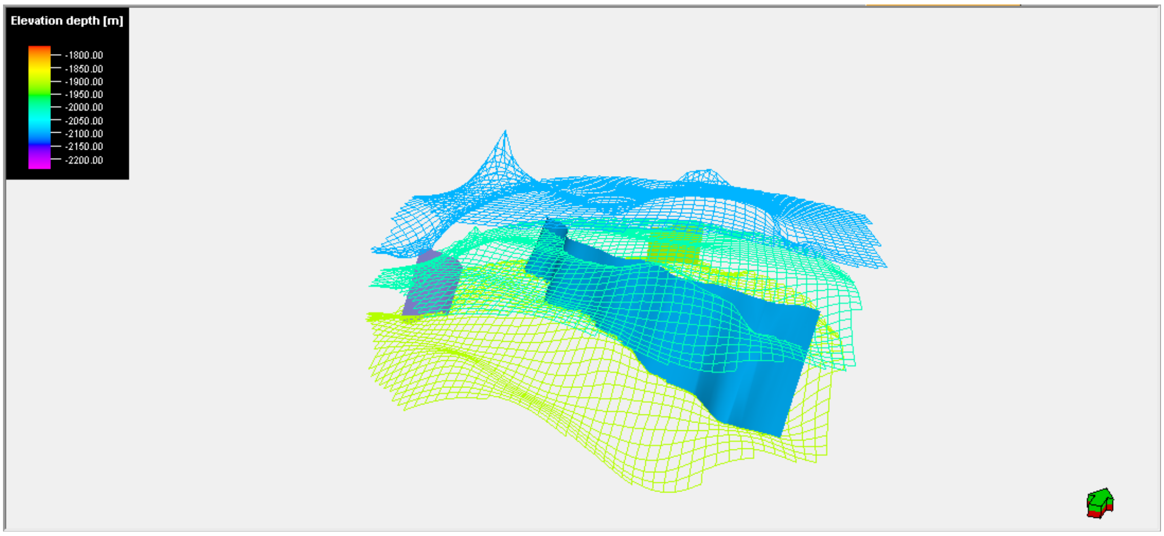

Fig.15: Skeleton Grid of Horizons Showing Faults Inside the Grid Model.

After creating the skeleton grid of the mode, it was followed by putting stratigraphic horizons in the model. This horizon helps to show the fault displacements in the model. The reservoir was then zoned into two distinct zones of percentages 30% and 70% representing Mid Turonian-Intra Upper Albian (96.5Ma) and Intra Upper Albian (98Ma) – Mid Albian respectively. These zones were further divided into several layers (Fig. 21)

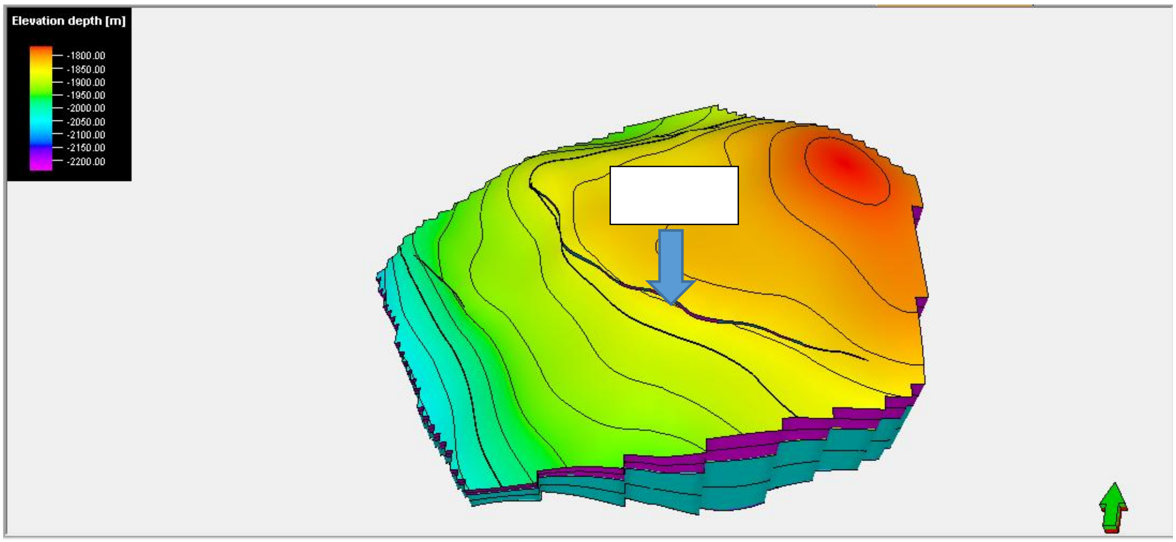

Fig.16: 3D Modelled Reservoir Zone from Interpreted and Modelled 3D Horizons and Faults.

5.5 Petrophysical modelling

The volume of shale shows the distribution of shale in the reservoir, porosity and water saturation shows the distribution of porosity and water saturation of the modelled reservoir zone (Fig 17a,b,c).

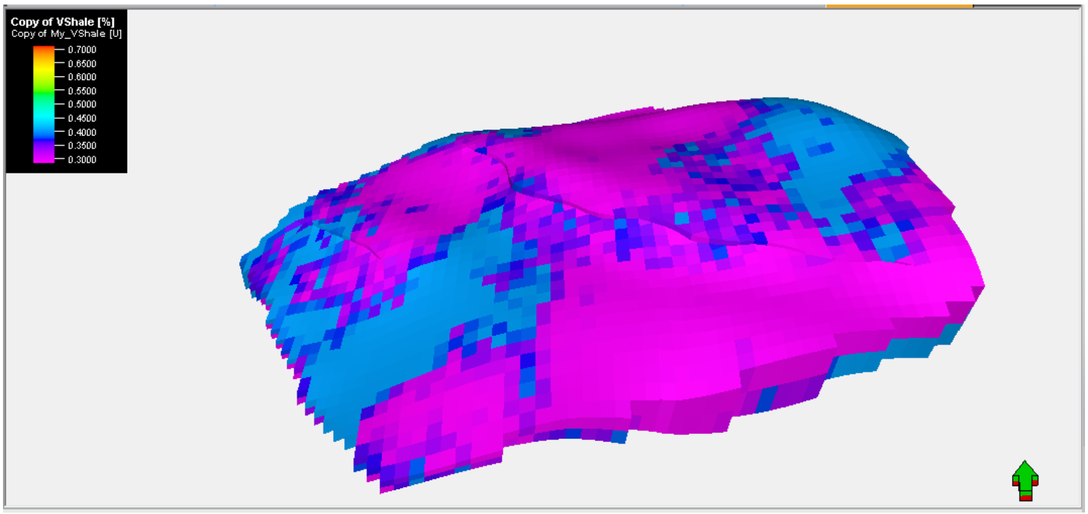

Fig.17 a: 3D Display of V-Shale Model with Most of the Reservoir Made Up of Low Volume of Shale.

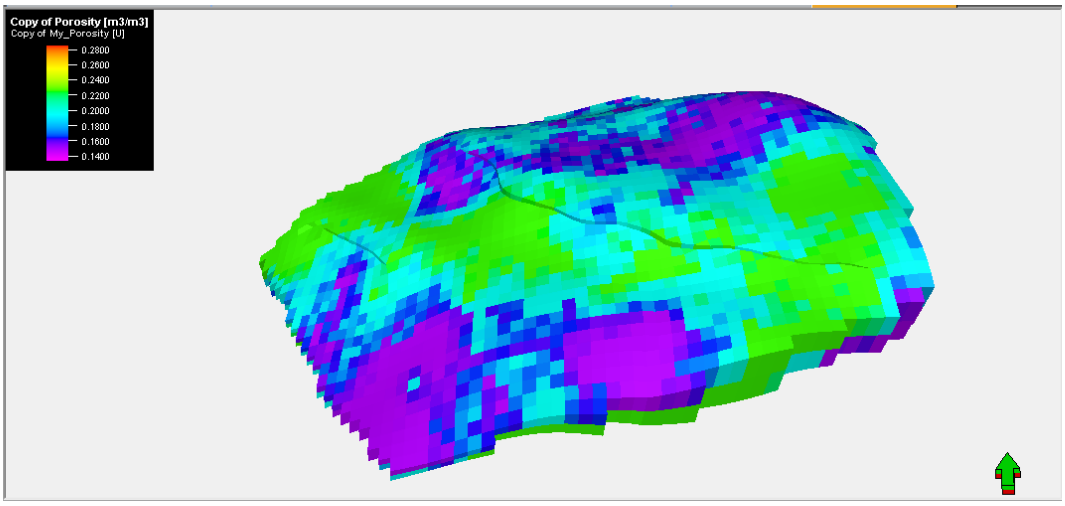

Fig.17b: 3D Display of the Porosity Model.

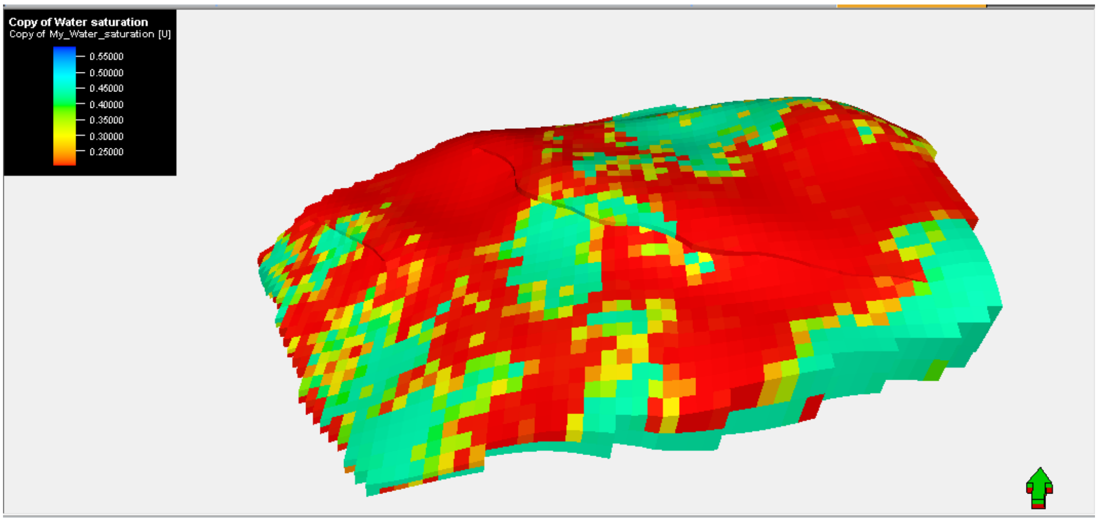

Fig17c: 3D Display of Water Saturation (SW) Model of the Reservoir.

5.6 Fluidcontacts and volume calculations

Oil water contact (OWC) and gas oil contact (GOC) weredetermined to allow for the calculation of crude oil and gas in the modelled reservoir (Fig.24a and 24b).

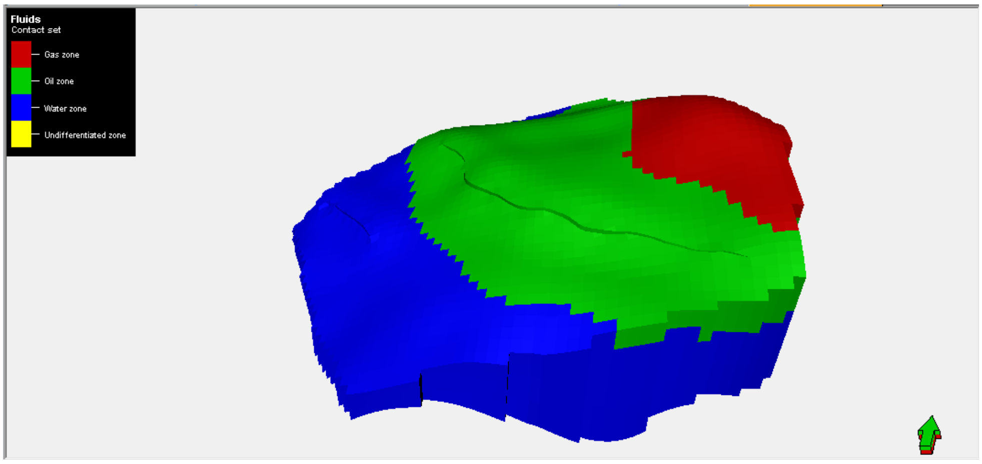

Fig.24b: 3D Display of Modelled Oil Water Contact (OWC) and Gas Oil Contact (GOC).

Volume calculation was done using the Monte Carlo approach. The volume calculated based on Monte Carlo simulation approach gave STOIIP of 1247x 10^6 million barrels and GIIP of 41x10^6standard cubic meters. Results for petrophysical parameters obtained from geophysical logs are shown Table 2.

Table 2: Petrophysical Results from Well Data

Wells	Porosity (%)	Water saturation (SW)	Hydrocarbon saturation (SH)	Gross Reservoir (GR) m.
1S-1X	24	0.43	0.54	18.51
1S-2X	22	0.47	0.53	13.45

VI. Discussion

Our seismic volumes produced high resolutionwhich made fault and horizon interpretation easier. The original seismic format SEG-Y was changed to petrel ZGY file format so as to facilitate and enhance operational speed of the software for the different analysis carried out.

In finding potential reservoir zones, well data in the form of wire-line logs and formation top allow for preliminary identification of reservoir zones, these zones were further confirmed from the seismic well tie.

The gamma ray log, resistivity log and formation tops played a vital role in delineating the reservoir zones to be mapped. Gamma ray log was used for lithology determination, sand zones were defined as areas having low gamma response on the log and shale zones having high gamma response due to the presence of heavy radioactive elements such as Potassium 40^{40}K, Uranium 238^{238}U, and Thorium 232 ^{232}Th that tend to concentrate in shale cite ref as Ojong et al .

Potential hydrocarbon zones were identified with the help of the resistivity log, as a high resistivity response indicates the presence of hydrocarbon and low resistivity response indicates the presences of water in the reservoir zone. Thus, zones along the logs which showed high resistivity and low gamma readings were chosen as potential reservoir zones and were then mapped. This interpretation is based on the fact that hydrocarbons offer high resistivity response to current (Baker Hughes INTEQ, 1998) and sand zones which are normally our reservoir rocks offer low gamma response, since sand have little or low concentration of radioactive minerals. The facies log generated for each well helped to further confirm the sand and shale zones identified from the gamma ray log.

Geophysicists and petroleum geoscientists obtain the location of horizons in depth through the seismic well tie process, that is tying seismic data and well log data. The seismic well tie process was based on the assumption that the seismic response of the subsurface rock encountered in the well can be treated as one dimensional problem (Bacon et al, 2003) and that the effect of the seismic wave through the earth can be calculated as though the interfaces between rocks in the subsurface are horizontal and the ray paths of the waves are vertical so the rays are normally incident on the interfaces (Bacon et al, 2003). In the seismic well tie, well 1S-1X gave the best results of the seismic well tie process.

After the seismic well tie process, the mappable horizons were identified, and the identified horizons fell within the reservoir zone. The identified horizons were middle Turonian (90 Ma) to -Intra Upper Albian (96.5ma) and Intra Upper Albian (98 Ma) to -Middle Albian. These horizons divided the reservoir zone into; the top, middle and bottom respectively. From these interpreted horizons, a clear structural high is seen on the gridded map of the horizon (Fig 4.7a). The structural high is a four-way dip closure or an anticlinal dip closure.

Surface attribute maps using the Root Mean Square (RMS) method were generated to further ascertain the character of the reservoir (Fig 4.9a). Sand zones corresponding to high seismic attribute values indicate that they are reservoir zones.

Faults were identified and interpreted in the realized seismic volume. Four major faults were interpreted, but three out of the four faults were modelled and this was based on the proximity of the interpreted faults to the interpreted horizons. The faults were generally trending NW-SE. Using the look up function, the faults were depth converted and used in the 3D-modelling of the reservoir zone.

The 3D model which includes modelled faults from fault pillar gridding of the interpreted faults and depth maps of interpreted horizons was made by dividing the model into zones, which were further divided into layers.

Property modelling in the form of cell angle and bulk volume was done, in order to make sure there are no negative bulk volume or twisted cell in the model because if present, will affect volume calculation. This negative bulk volume and twisted cell usually results from errors in fault modelling. But no negative bulk volume and twisted cell were found in the model and thus making accurate volume calculations possible.

Petrophysical modelling in the form of populating the reservoir model was carried out. These included porosity modelling, V-shale, and Water saturation modelling (Fig4.17a,4.17b, and 4.17c). This was done by first scaling up the necessary well logs.

Well 1S-1X showed good petrophysical results with porosity of 24%, water saturation (SW) of 0.43, hydrocarbon saturation (SH) of 0.54 and Gross reservoir thickness of 18.51m. Well 1S-2X showed petrophysical properties with porosity of 22%, SW of 0.47, SH of 0.53 and gross thickness of 13.45m. The above porosity values are good for a sand reservoir (cite ref).

Fluid contact analysis was carried out, and the main type of fluid contacts were oil water contact (OWC) and gas oil contact (GOC). The GOC and OWC were established at a depth of 1828m and 1923.99m respectively. Volume calculation was carried out using the Monte Carlo approach giving a STOIIP of $1247x10^6$ million barrels (bbl) and GIIP of $41x10^6$ standard cubic meter (sm^3).

VII. 7conclusions

The reservoir zone in the South Tano field can be found between the Mid Turonian (90 Ma) to Intra Upper Albian (96.5 Ma) and Intra Upper Albian (98 Ma) to Mid Albian. The integration of seismic and well data was successful in defining the subsurface geology and hydrocarbon potential of the reservoir zone. From the above tie, the reservoir is an anticlinal dip closure and is structurally controlled by faults. The reservoir zone which falls between Mid- Turonian (90 Ma) to Intra Upper Albian (96.5 Ma) and Upper Albian (98 Ma)-Mid Albian are most the most petroliferous zones. An exploration well should be drilled at the eastern flanges of the anticline as we see reflectors terminating at that point of the anticline, hence we might likely be having a pinch out stratigraphic trap and this may present the opportunity of find new pay zones in the south Tano field for petroleum exploitation.

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