

Reservoir Property Prediction Using Well Logs and Attribute Maps
Generated from 3D Seismic Data for Reservoir Characterisation

by

MARINA ROSINE AFFOUA TWIMASI, BSc. Materials Eng.

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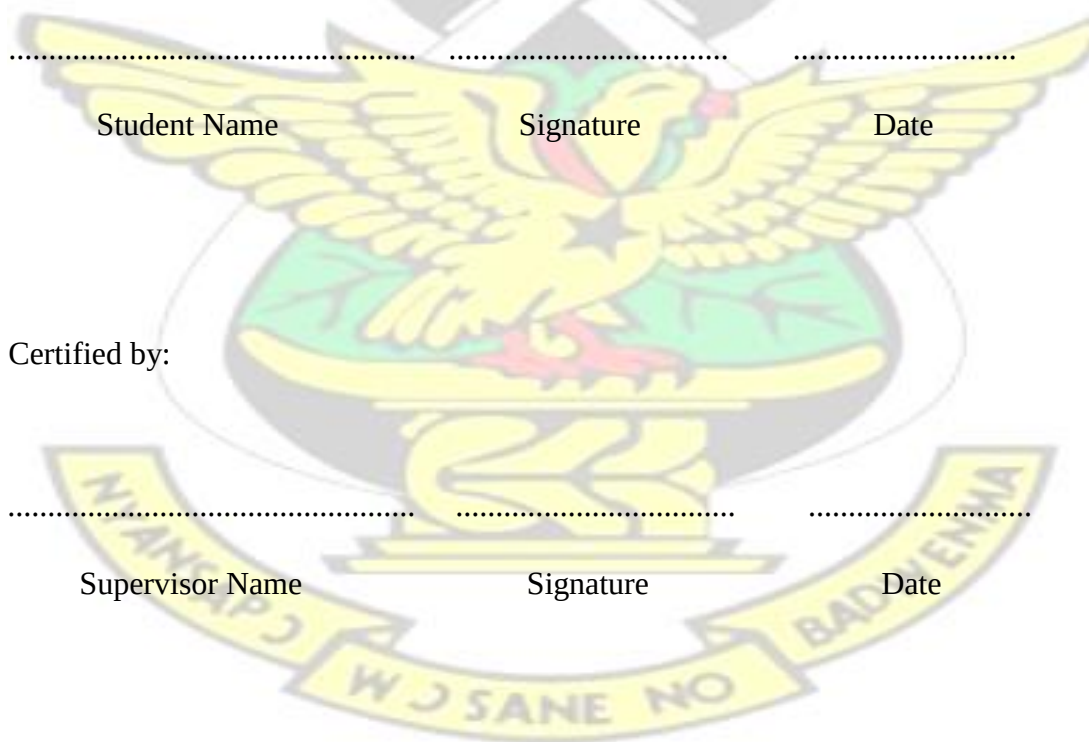
Department of Physics

Supervisor: Prof. Aboagye Menyeh



DECLARATION

I hereby declare that this submission is my own work towards the MPhil. degree and that, to the best of my knowledge, it contains no material previously published by another person nor material which has been accepted for the award of any other degree of the University, except where due acknowledgement has been made in the text.



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Student Name	Signature	Date
Certified by:		
.....		
Supervisor Name	Signature	Date

Certified by:

Head of Dept. Name	Signature	Date
.....		

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LIST OF
SYMBOLS AND
ABBREVIATIONS

VSP	Vertical Seismic Profiling
3C	Three-Component
2D	Two-Dimensional
3D	Three- Dimensional
$D\rho$	Density correction log value
V_p	Velocity of primary wave
V_s	Velocity of secondary wave
API	American Petroleum Institute
ROP	Rate of Penetration
GR	Gamma Ray
C.I	Contour Interval
RMS	Root Mean Square
GRV	Gross Rock Volume
TVT	True Virtual Thickness
Kya	Thousands of years ago
Mya	Millions of years ago
Gya	Billions of years ago
CMP	Common Mid-Point
AVO	Amplitude Versus Offset
p. u	Porosity Unit
bbl/STB	Stock Tank Barrel at Surface Conditions
mD	milliDarcy

ABSTRACT

This research sought to determine the properties of a reservoir in the Western Tano Basin using well logs and attribute maps generated from 3D seismic data, in order to counter the relatively limited vertical resolution that comes with using only seismic data to characterise reservoirs. A network of four horizons (The Seabed, Top Upper Reservoir, Middle Shale and Base of Reservoir) were identified and mapped. Seismic data was used to identify the lithology and structure, and contour mapping of the horizons revealed the trapping systems in each layer. Amplitude extraction was performed to confirm the presence of the reservoir, and attribute mapping was used to generate the architectural elements which describe the location and distribution of the sand packages in the reservoir. Two well-containing zones (UP and LP) were selected as areas of interest due to the sand distribution density and availability of sufficient log data to corroborate the assumptions made. Wireline petrophysical parameters were extracted from log data within the intervals of investigation and used to calculate petrophysical properties. The result depicted very good porosity (21.2 & 20%), permeability (408.2 & 182.9 mD), oil saturation (88.2 & 85.2%) and original oil in place (104.56729 & 388.055×10^6 bbl/STB) values for the upper and lower intervals respectively. Comparing both intervals, the lower interval proved more productive and could be the reason for the presence of two wells in close proximity to each other in that area. According to the literature, the petrophysical values compared favourably to those of commercially exploitable reservoirs. This research therefore provides an excellent method for the integration of log data, attribute maps and 3D volume seismic data to determine reservoir properties with increased quality and accuracy, due to the added improvement of enhanced vertical resolution.

DEDICATION

This work is dedicated to my wonderful parents and family, my loving husband Kwaku, and my beautiful children Jadelyn and Antoine.

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CHAPTER 1

INTRODUCTION

1.1 BACKGROUND OF STUDY

Reservoir characterization is a combined technology associated with geophysics, geology, petrophysics, geostatistics and reservoir engineering. The main goals of reservoir characterization research are to aid field development and reservoir management teams in describing reservoirs in sufficient detail, as well as in developing 3D/4D data for reservoir development planning. This consequently enables higher recoveries with fewer wells in better positions at minimum cost through optimization, increasing reserves, improving stimulation and completion practices, and reducing to a minimum the uncertainty in production forecasts (Haldorsen and Damsleth, 1993). Reservoir characterization thus plays a vital role in the oil and gas industry, providing important information on the location, quality, quantity and exploitability of the resources in a reservoir. In the last five decades (since the publication of Jahns' first technical paper entitled: two-dimensional description of reservoir heterogeneity using regression analysis on well testing data (Jahns, 1966), reservoir characterization has attracted remarkable research efforts (Doss et al., 2001). It is widely recognized now by the industry that reservoir characteristics such as natural heterogeneity, spatial variability of permeability and porosity, porous media properties and spatial distribution of oil & water predominantly control the field flow, reservoir performance, development strategies and hence the economic returns of investments- which is of great importance to petroleum companies.

Recently, technological innovations have led to advances in reservoir characterization through seismic imaging technologies- either single-sensor seismic data processing or calibration of seismic amplitude and attributes. These showed advantages in porosity

detection and reservoir modelling (Slatt and Mark, 2002). Surface microseismic monitoring is being used for hydraulic-fracture monitoring in reservoir characterization of the development stage (Duncan and Eisner, 2010). In addition, Vertical Seismic Profiling (VSP) is also a technique which is effective in distinguishing small structures near the wellbore, in identifying lithology, and in obtaining fracture parameters. Combined with seismic data interpretation, this technique can provide near wellbore parameters for reservoir characterization.

Seismic data has always been an important method for reservoir prediction. For reservoir characterization, it provides not only fine structure interpretation but also inter-well information which is determined by extrapolation of adjacent well data, or derived directly from seismic interpretation for the formation of geological models (Refae et al., 2008). There has however been limited application of using seismic data alone to help directly map intra-well reservoir properties such as porosity, permeability, hydrocarbon saturation etc. Due to low vertical resolution, petrophysical properties and hydrocarbon distribution derived from seismic data usually cannot fulfil the need of development planning. Cross-well petrophysical properties and hydrocarbon distribution are still great challenges- as sustained recovery of oil or gas from porous media, reservoir properties, pressure and fluid distribution are changing with time. Improvement of vertical seismic resolution is therefore the precondition for the application of seismic data into reservoir characterization at the development stage. With the knowledge that well data provides the needed enhanced vertical resolution, it has become evident that the best way to tackle this challenge is through the integration of seismic and log data (through the aid of synthetic seismograms) in order to provide the sufficiently improved vertical resolution needed for more accurate reservoir characterisation. Well Logging or borehole drilling is however very expensive and

time consuming, leaving no room for errors. This therefore requires extensive knowledge of the techniques needed to analyse and quantify reservoir properties to the highest precision possible. The literature however, shows that there has not been enough research done detailing step by step the methodology required to extract the needed information from well logs by merging them with seismic data obtained from near the well surface and consequently, generating data that is accurate enough for successful integration into reservoir characterisation.

This research therefore seeks to contribute information to that effect by analysing the properties and calculating the petrophysical parameters of an active, oil-producing reservoir in the Western Tano Basin.

1.2 ORGANIZATION OF STUDY

The first chapter will present an overview of the research, its objectives, its scope and significance.

The second chapter will focus on subject matter-related literature review to provide a background for understanding the content and results of this research.

The third chapter will outline the methodology used to generate the data required to achieve the research objectives. Specifically, it will include log and seismic data interpretation steps, as well as the detailed procedures used to generate the attribute maps used in identifying the hydrocarbon bearing zones in the reservoir.

The fourth chapter will be concerned with the results analysis and discussion.

The fifth chapter will draw the curtains by providing a summary of findings, conclusions and recommendations in relation to the key issues of the research problem and objectives.

1.3 PROBLEM STATEMENT

Despite the advancement in reservoir characterization development over the years, the oil and gas industry is still faced with a lot of challenges. Some are due to the everlasting high heterogeneity and diversity of reservoir rocks, the difficult characterizing methods for reservoir framework, and the ever changing pore structure and fluid flow units. Others are motivated by problematic reservoirs that have thin beds, low-permeability characteristics, low-resistivity-contrast pay, laminations and fracture networks. Till date, there is still no substitute for high quality seismic interpretation that may reveal essential geological features and important heterogeneities in greater detail. Methods such as Vertical Seismic Profiling (VSP), inter-well seismic, and time-lapse seismic (4D) technologies etc. have been calibrated with seismic processing and interpretation but the technique is however still short of adequate vertical resolution for the effective diagnosis of small-scale structures or architecture elements. Just as (Haldorsen and Damsleth, 1993) remarked: “The industry wants a one-meter resolution at typical North Sea reservoir depths before the turn of the century!”. Achieving improvement in vertical resolution is therefore the goal of the geophysical industry. In the meantime, devising alternative methods to provide better data quality has become the developmental trend.

The evaluation of petrophysical reservoir properties and fluid distribution models are key parameters in reservoir characterisation. They should be integrated with the reservoir framework model to obtain a comprehensive reservoir model. Currently, reservoir properties are derived from laboratory-based core analysis and well logs. Reservoir fluid can be identified through seismic surveys or sampling. Their spatial distribution predictions are reached through seismic interpretation or extrapolation of well data. It can be found that these methods are based on static data without the

consideration for reservoir dynamic characteristics, and is thus suitable for oilfields at the exploration stage or early stage of field development. For oilfields at the middle or mature stage of development however, studies on reservoir properties and fluid distribution are more complicated- especially for oilfields undergoing long-term water flooding. Reservoir properties change a lot with the advance of field development. Oil zone permeability, rock cementation, production rate and oil viscosity are all control factors to property changes. Highly permeable channels (large pores) gradually develop in highly flooded zones causing ineffective water circulation and seriously affecting the displacement efficiency. Other reserves remain abundant in non-swept areas whereas water blockage will take place in low permeable zones causing additional permeability reduction. Reservoir characterization at the middle or mature stage of field development should thus take the changes of reservoir properties into consideration, especially the distribution of highly permeable channels (Haldorsen and Damsleth, 1993).

Since repetitive coring- in order to measure the instantaneous conditions in the reservoir is impractical and very expensive, there is the need to find a more efficient way of predicting reservoir parameters at any stage of field development. This may be effectively achieved through the combination of log and seismic data, but in order for it to be done accurately and in a cost effective way (which is imperative to oil and gas companies), sufficient information should be made available to student geophysicists and engineers- especially Ghanaians, so that they may be equipped with the technical skills required to partake in and benefit from the country's prosperous and ever expanding oil and gas reserves.

1.4 RESEARCH OBJECTIVES

This study seeks to achieve the following objectives:

- Define the structure of the reservoir from log and 3D Depth Volume seismic data
- Generate attribute maps from seismic data
- Identify sand zones in the reservoir
- Perform volumetric analysis on sand intervals to determine the gross sand volume
- Obtain reservoir property values from well logs and perform petrophysical analysis on the gross sand intervals to locate and quantify hydrocarbon bearing zones

1.5 SCOPE OF STUDY

Through the aid of the facilitating company Ghana National Petroleum Corporation (GNPC), this study will involve the application of three different types of information in the form of attribute maps, 3D Depth volume seismic data and well logs for the 7 wells present in the 696.88 km² surface area of investigation, located within the Western Tano Basin. The precise location from which the area of study was carved out will however be withheld to preserve data anonymity for confidentiality purposes. Hydrocarbon quantity calculations will be limited to sand intervals that display the strongest seismic amplitude responses and concurrently possess a well/wells with sufficient log data for petrophysical calculations.

1.6 SIGNIFICANCE OF STUDY

The 25 new discoveries of oil and gas condensates since the historic 2007 oil find by Kosmos Energy -as disclosed by Mr. Theophilus Ahwireng (the Chief Executive of the Petroleum Commission) to a Joy News reporter proceeding his presentation at the

closing session of the ECOMOF 2015 conference, has proven that the Ghanaian oil and gas industry is growing at an astronomically fast rate. The emergence of these and any future finds require adequate geophysical and geological exploration in order to test the economic value of exploiting such resources in the most efficient, cost effective way.

It has therefore become important for local geophysicists and geoscientists to be equipped with these valuable skills, hence minimizing the costly need to always resort to employing foreign companies to undertake such works, leaving the country with nothing but scraps in the process. This research will therefore provide an insight into how to improve reservoir characterization through the supply of reservoir parameters which can be accurately obtained from log and seismic data at any stage of the oilfields' development, in a cost effective way.

By supplying Ghanaian engineering and geophysics students with the findings obtained from this research, they will be better equipped to compete with foreigners for data acquisition, processing and interpretation jobs and hence be the major benefiter of the nation's prosperous oil and gas industry. This in consequence will enable the government to gain more funds through taxation of such citizens, making additional funds available for other national developmental projects.

CHAPTER 2 LITERATURE REVIEW

2.1 REVIEW OF RELATED RESEARCH

Reservoir characterization is basically the process of mapping a reservoir's thickness, net to gross ratio, pore fluid, porosity, permeability and water saturation (Eshimokhai and Akhirevbulu, 2012). Reliable economic evaluation of a reservoir demands reliable

characterization of reservoir properties. Well log data assists in seismic analysis, reservoir modelling and fluid substitution by providing valuable information for characterising reservoirs. Through the provision of petrophysical parameters, the development and production of the drill well is facilitated and in consequence, the estimation of reserves in any oil or gas reservoir can be obtained (Islam et al., 2013).

Internationally, considerable efforts have been extended to enhance reservoir characterization by improving reservoir property acquisition techniques through the integration of seismic and well log data. In 2006, Natalia Soubotcheva investigated reservoir property prediction from well logs, VSP and multicomponent seismic data on the Pikes Peak heavy oilfield in Saskatchewan (Soubotcheva, 2006). Using data from a three-component seismic line -obtained from the University of Calgary's CREWES Project in March 2000, in collaboration with a Canadian company (Husky Energy Inc.)- and log data from the nine wells situated closest to the seismic line, the geophysical interpretation began through the correlation of well logs to seismic data via synthetic seismograms. From it, a reasonable correlation in the data types between the logs and resultant zero-phase synthetic seismograms was obtained (with a synthetic-surface seismic correlation coefficient of 64%) for the first six wells. A composite plot consisting of well logs, synthetic seismograms, VSP data and surface seismic data was then assembled in order to facilitate the interpretation process.

Inversion and other attributes were employed to predict the reservoir properties along the seismic line and examples of predicted porosity and density sections were displayed and interpreted. The V_p/V_s values that were calculated enabled the discrimination between sand and shale. The beginning of the Colony formation was identified from the considerable drop in V_p/V_s ratio (from 4.4-1.7). The region displaying an increase in P_s and drop in P_p impedance value was also identified as the

top of the productive zone, whilst an anomalous zone of low-frequency was observed just below the reservoir. The entire productive zone was defined by sudden increased porosity (22%) and decreased density (2170 kg/m^3) values. The combination of the different types of information had hence permitted a greater understanding of the acquired data and consequently, a more successful development of the existing fields (Soubotcheva, 2006).

A year later, Benedictus investigated the determination of petrophysical properties from the well logs of the offshore Terschelling Basin and Southern Central Sea Graben region (Benedictus, 2007). During the study, the core samples from specific intervals in seven different wells were taken and employed in porosity, matrix density calculations and in lithological identification. In order to gain an insight into lithology and its relation to well log expressions, several litho-stratigraphic units in the drilling cores were investigated. Because the purpose of the study was to produce porosity estimates from well logs which generally lacked core-measured porosity values, the theoretical methods of calculation were preferred over the empirical relationship between porosity and the well log signal- since theoretical calculations are less influenced by local conditions and therefore more widely applied. At the end of the study it was observed that bulk density logs were favoured over sonic and neutron logs in the calculation of porosity values due to several reasons. These were namely; the existence of a clear and linear theoretical relationship between bulk density and porosity, the availability of high resolution data on matrix densities for cored intervals in many litho-stratigraphic units of multiple wells, and the possibility to evaluate fluid density values directly from resistivity measurements. Although well logs are the most adequate for calculating porosity, it was recommended that they be automatically disregarded if the density correction log value ($D\rho$) was seen to exceed 0.15 or -0.15

g/cm³, or if the bulk density log itself showed values below 2.0 g/cm³, as its accuracy could no longer be trusted (Benedictus, 2007) .

Similarly, (Eshimokhai and Akhirevbulu, 2012) also provided a comprehensive description of the process by investigating logs and seismic data from three selected reservoirs in a section of the Niger Delta. An integrated technique was used in computing various Petrophysical parameters. The well logs used were namely gamma ray, neutron, density and resistivity logs. These logs were combined with various mathematical equations in the evaluation of petrophysical parameters including the shale volume, porosity, water saturation and hydrocarbon saturation. In order to establish and reduce interpretational errors, the results were compared with recommendations made from the results of random core samples of the selected wells. The findings revealed that the hydrocarbon interval in the areas occur between the depth range of 5150 – 5198 m for Well 1, 5233 – 5260 m for Well 2 and 5353 – 5400 m for Well 3. The gamma ray and the resistivity logs showed that the reservoirs contained good quality sands with porosities averaging between 0.26 – 0.34, water saturation averaging between 0.09 - 0.32, hydrocarbon saturation between 0.77 – 0.83 and thickness of the reservoirs sands ranging from 27– 48 m. In addition, it was determined from the well to seismic tie that the sands were hydrocarbon bearing- as hydrocarbon indicators were displayed on seismic section.

2.2 THEORY

2.2.1 Petroleum System of the Tano Basin

Oil and gas occurrences in the Gulf of Guinea Province are concentrated in Cretaceous reservoirs on the continental shelf and adjacent onshore extensions. Before 1995, most of the discoveries in the province had only been located at water depths of less than

500 m. Now, at least five total petroleum systems have been identified in the province, although the existing exploration and production data in the province is mostly limited to Cretaceous rocks (Brownfield and Charpentier, 2006).

According to Tetteh, (2016), the Tano basin is comprised of a thick Upper Cretaceous drift section dominated by stratigraphic traps, basin floor fans and channel systems, and is associated with oil seeps and tar sand accumulations along the Upper Cretaceous outcrops west of Cape Three Points. Shallow marine to continental deposits make up the rift section and the Albian shales act as source rocks, whilst the Turonian slope-fan turbidite and Albian sandstones in tilted fault blocks act as the reservoirs. The trapping mechanism is both structural and stratigraphic and because the reservoirs are predicted to be in close proximity to the source rocks, a minimum migration pathway is assumed.

2.2.1.1 Hydrocarbon Source Rock

The Tano Basin consists of three source rock plays. These are the Upper Albian, the Cenomanian and the Turonian. They were all deposited as a result of the creation of the pull-apart basin and are entirely comprised of shales (Atta-Peters and Garrey, 2014). The anoxic oceanic conditions that characterized the middle Cretaceous period worldwide also affected the Gulf of Guinea during the Cenomanian age and this resulted in the deposition of the sediments that later formed the Albian and Cenomanian black shale source rocks. This depositional event marked the first marine transgression in the Gulf of Guinea and was accompanied by a decrease in the subsidence rate in the province (Brownfield and Charpentier, 2006).

The Anoxic conditions continued into the Turonian and samples analyzed from deep sea drilling sites both north and south of the Gulf of Guinea indicate that these rocks contain more than 10 weight percent organic matter consisting of Type II kerogen. In

most cases, these source rock plays are interbedded with reservoir rocks that consequently serve as a charging source (Atta-Peters and Garrey, 2014).

According to MacGregor et al., 2003, gas-prone source rocks were identified in the Lower to Middle Albian age. They form part of a sequence which contains approximately 5,000 m of Lower Cretaceous continental to marginal marine rocks deposited in grabens in the Tano Basins (Chierici, 1996). Figure 2.1 describes the location of the source rocks in the Lower and Upper Cretaceous Epochs.

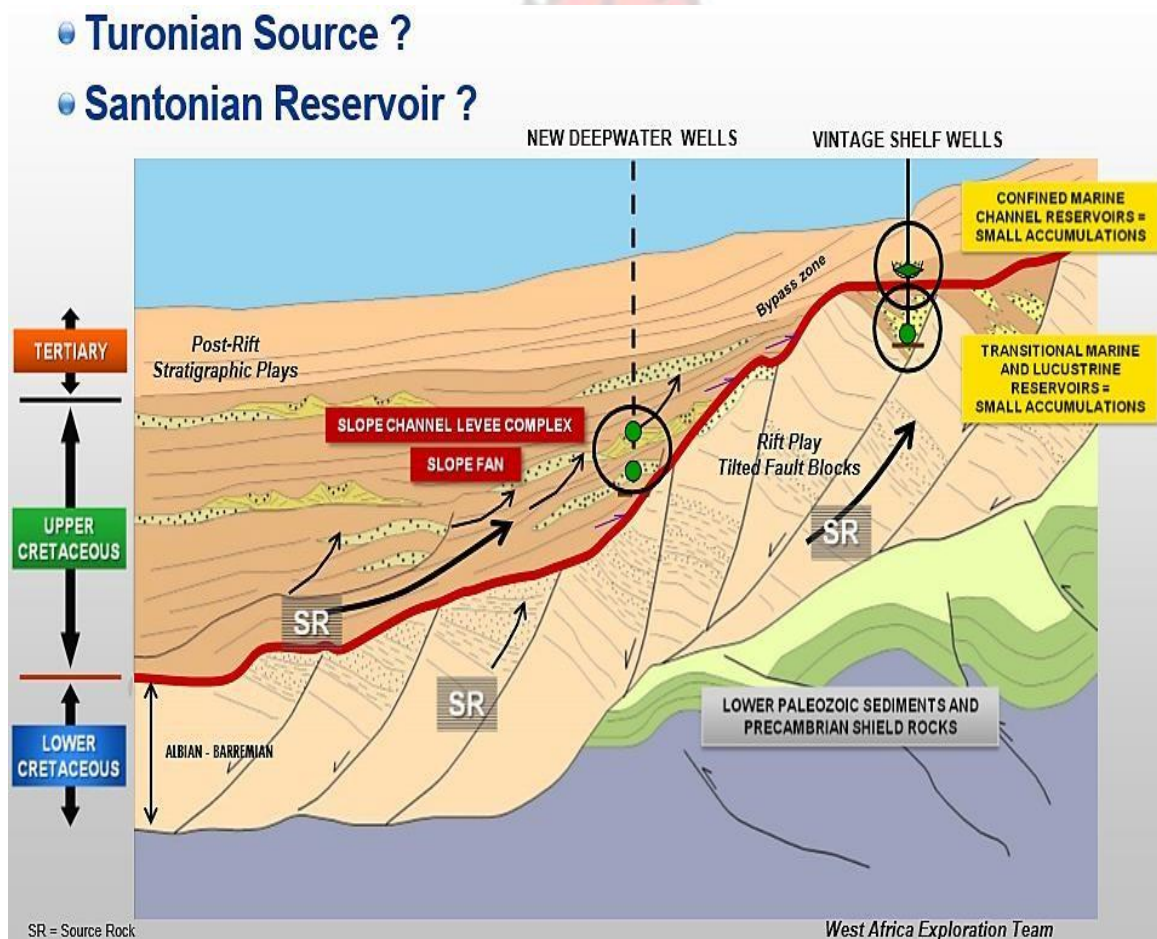


Figure 2.1 Foundation of source and sediment system for cretaceous fan play, (Anadarko, 2011)

The kerogen types available in Tano basin are mainly type II and type III, although a few well samples indicate the presence of type I and type IV. This proves that the basin

has the potential to yield both oil, gas or gas condensate, provided it has been thermally matured at an adequate burial depth. In terms of thermal maturity, the data from an investigation carried out by Atta-Peters and Garrey (2014) showed that most of the source rock samples taken fall within the range of an immature to marginally mature source rock. The maximum temperature data also indicated that the samples taken from a well south of the basin fell within the oil window, and those taken from the other well fell just below the oil window (Atta-Peters and Garrey, 2014).

2.2.1.2 Hydrocarbon Generation and Migration

The most important hydrocarbon generation within the Gulf of Guinea Province is from the upper Albian and Cenomanian source rocks, which are distributed throughout the offshore part of the province (Brownfield and Charpentier, 2006).

It is expected that these strata will increase in source rock quality and thickness in deep waters. According to the interpretation by MacGregor et al., (2003), there are two main areas of hydrocarbon generation in the province. These are the offshore parts of the Ivory Coast and Tano Basins, and the offshore parts of the Keta and Benin Basins. These probable oil kitchens are only present in the deep waters where the source rocks have a temperature of at least 100°C and a vitrinite reflectance (R_o) of 0.6 percent (MacGregor et al., 2003). These values are roughly equivalent to having source rocks subjected to about 2,700 m of overburden rock. In the lower Cretaceous period, two areas of hydrocarbon generation created from custrine source rocks have been identified. They are associated with the tar sand and oil seep accumulations which have been identified along Upper Cretaceous outcrops in the onshore parts of the Tano Basin.

In the Tano Basin, hydrocarbon generation started in the Late Cretaceous period and continues to the present day. During this epoch, a deltaic complex developed and

deposited thick layers of basin floor fans and turbidity flows in the deepening basin. These large fan systems are the ones that form the main reservoirs in the Jubilee, Tano and Odum fields (Whaley, 2010).

During the Cenozoic times, when the whole offshore area was deposited, a thick transitional marine sedimentary package was deposited.

2.2.1.3 Hydrocarbon Reservoirs

The stratigraphic units that contain proven reservoirs in the shallow-water discoveries in the Gulf of Guinea Province are mainly late syn-transform Albian sandstones and Cenomanian to Maastrichtian post-transform, marginal marine and turbidite clastic rocks (Brownfield and Charpentier, 2006). In the Tano basin, there is the presence of the clastic Albian rocks which are typically characteristic of the Ivory Coast. These rocks are believed to have been deposited in several different depositional settings, including fluvial through fluvio-deltaic, lacustrine, and marginal marine to marine and submarine fans.

There are three main reservoir plays in the Tano basin. These are the Albian Reservoir play-which consists of the Lower Albian to Upper Albian Age, the Cenomanian play from the Cenomanian age and the Turonian Series, all of which have sandstone lithology (Tetteh, 2016).

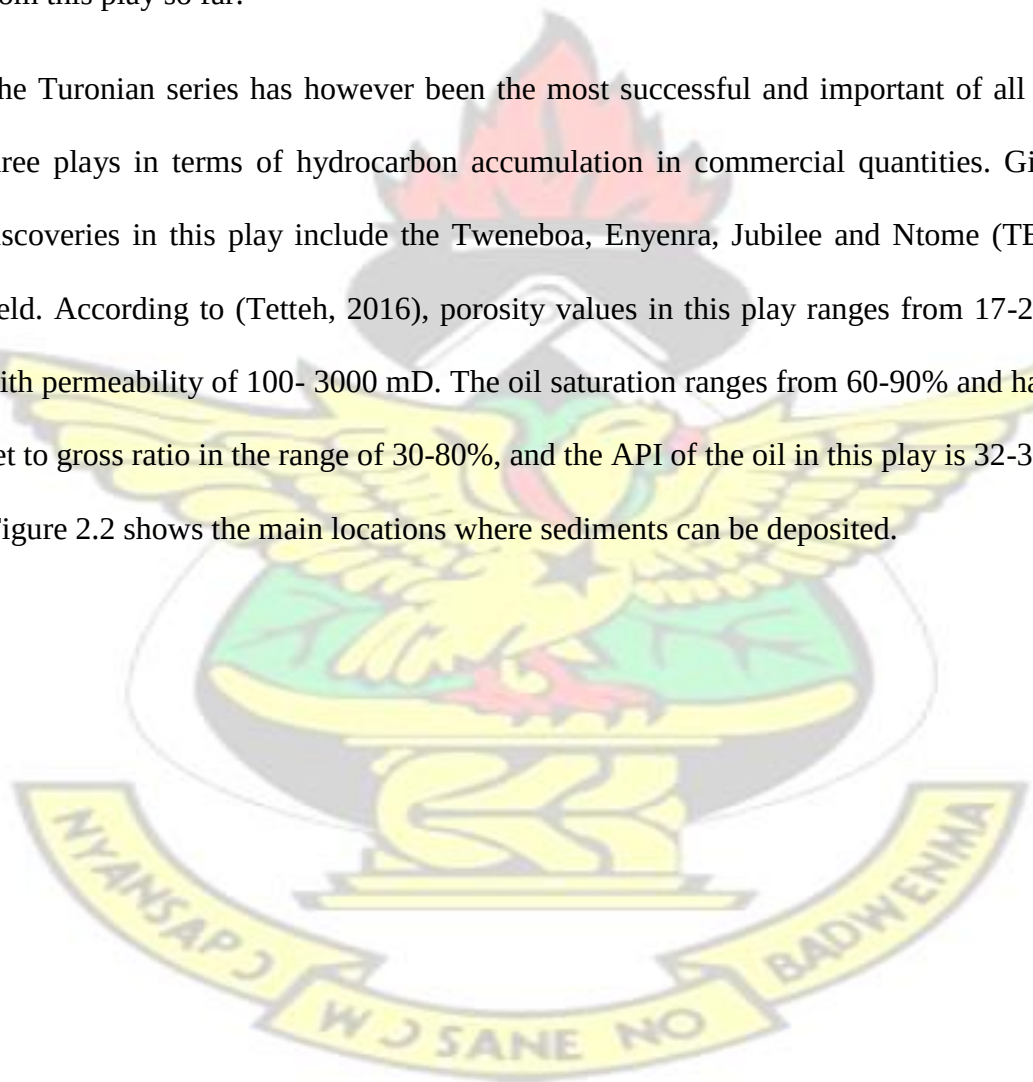
Many of the sandstone reservoirs have been characterized as being laterally discontinuous and exhibiting variable petrophysical properties across short distances. Some Albian reservoirs have also penetrated into the Tano Basin below the mid-Albian unconformity (Kjemperud et al., 1992; MacGregor et al., 2003).

There has so far been only one discovery in the Albian sandstone reservoir- which encountered oil and gas with net thickness of 25 m deep water Tano. This sandstone possesses good reservoir properties such as porosity values ranging between 17 and 22%, permeability values as high as 2000 mD and a maximum oil pay of 58 m (Tetteh, 2016).

The Cenomanian sandstone reservoirs have also not been very successful in the accumulation of hydrocarbons in the Tano basin- since there is only one discovery from this play so far.

The Turonian series has however been the most successful and important of all the three plays in terms of hydrocarbon accumulation in commercial quantities. Giant discoveries in this play include the Tweneboa, Enyenra, Jubilee and Ntome (TEN) field. According to (Tetteh, 2016), porosity values in this play ranges from 17-23% with permeability of 100- 3000 mD. The oil saturation ranges from 60-90% and has a net to gross ratio in the range of 30-80%, and the API of the oil in this play is 32-38°.

Figure 2.2 shows the main locations where sediments can be deposited.



Sedimentary Depositional Environments

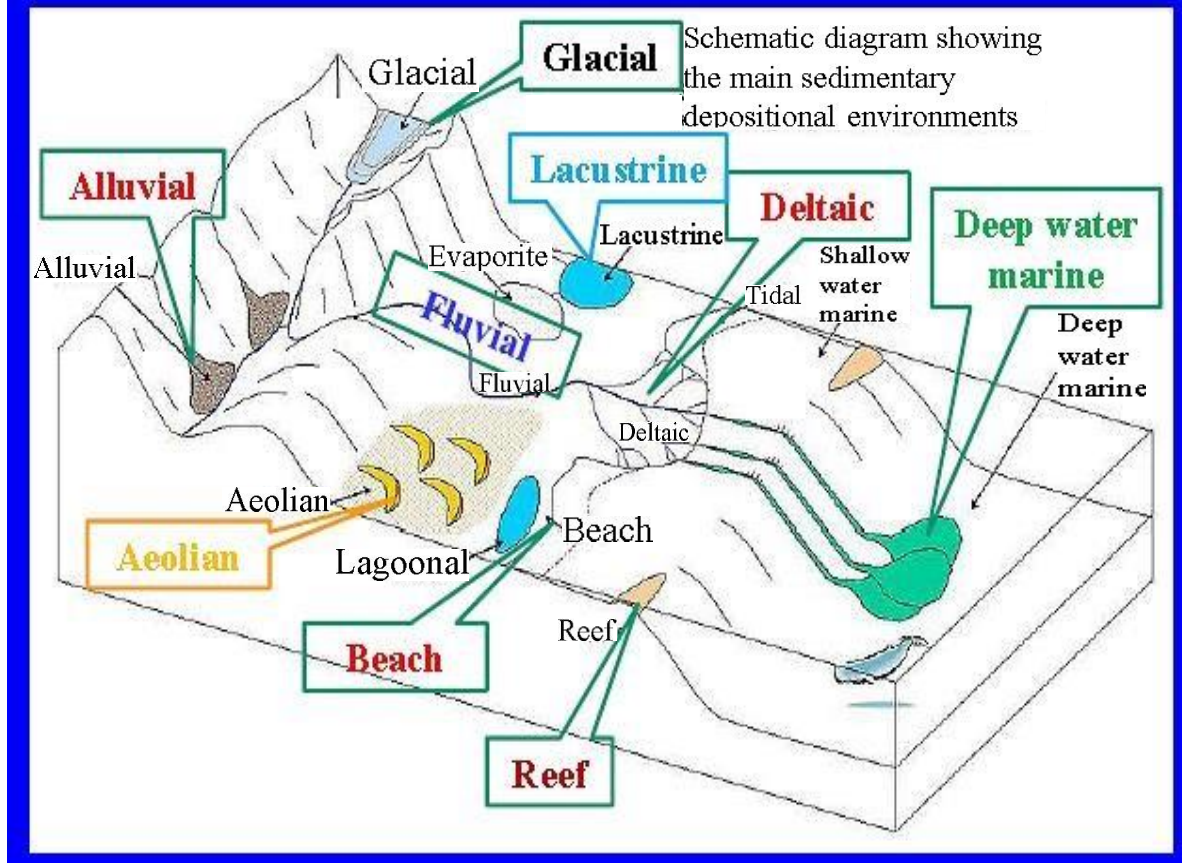


Figure 2.2 Schematic diagram showing the main sedimentary depositional environments (Harilal, 2012).

2.2.1.4 Hydrocarbon Traps and Seals

The Tano basin exhibits both structural and stratigraphic traps (e.g. pinch out traps, salt domes, anticlines and faults). The proven accumulations of hydrocarbons associated with fault-block traps are located in the upper part of the syn-transform section throughout the Gulf of Guinea Province in shallow to moderate water depths (MacGregor et al., 2003). This type of trap is characteristic of the Tano field and extends onto the continental slope. There are also fault-block traps located along the Romanche fracture zone.

Post-transitional anticlinal traps are another type of traps which have been detected in the Tano Basin. In addition to that, untested stratigraphic traps consisting of channels interbedded with the Cenomanian formation, and mounded sandstones were also detected in this era.

In the Albian play the trapping mechanism is mainly by structural traps such as Domes, Anticlines and Fault blocks. Above the late Albian unconformity, thick and extensive sandstone units covering areas more than 80km into the deep-water parts of the basin were observed by MacGregor et al., (2003).

Due to the steep nature of the continental shelf and the fact that it was subjected to several low stands along its margin, the deposition of detached, deep-water sandstone units, clastic fans and ponded turbidite sands was favoured. The downslope projections of deltas that were formed at that time are therefore prospective areas for probable turbidite channel and ponded turbidite sandstone reservoirs. The current interpretation that large fans or detached sandstone bodies may lie in the deeper parts of the basin is supported by the presence of these large turbidite channels. In general, the reservoirs in the early post-transform section are likely to be of better quality than those in the syn-transform section (Whaley, 2010).

Down-to-the basin faults can act as barriers to hydrocarbon leakage at locations where reservoirs are juxtaposed against relatively non-permeable rocks.

The Cenomanian play possesses both structural and stratigraphic traps formed with Draping structure, pinch outs, Clastic depos lens, anticlines and faults. Similarly, the Turonian play has both structural and stratigraphic traps such as pinch outs, normal faults, clastic depos lens and anticlines. The Tertiary era has however not proved

productive and this is probably due to the fact that there are not enough traps of sufficient size to warrant exploitation (Atta-Peters and Garrey, 2014).

In summary, the good overburden, the deposition of the marine shale, the anoxic conditions in the basin, the high porosity and permeability, and the good trapping mechanism in the Tano Basin has rendered it very productive and a big player in hydrocarbon production in Africa.

The seal play in the basin involves the Albian shale series, the Cenomanian Shale series and the Turonian Shale series. Most of the seals in the basin are formed from marine shale which are in close proximity to the reservoir rock. This thus promotes a very short migration of crude oil (Atta-Peters and Garrey, 2014).

Proof quality seals are often characteristics of fairly high-pressure wells and the local fault patterns and unconformity surfaces actively contribute to seal integrity. The continued extension and subsidence of the fans in the Tano Basin resulted in the deposition of thick shales which seal Jubilee and the other prospects in the margin.

An example of a stratigraphically sealed channel is Dana's Maastrichtian West Tano oil discovery. Seals associated with syn-transform reservoirs are formed by both shales and faults, whereas those associated with post-transform reservoirs are generally shales. This is especially evident in places where the shelf is steeper, and there is a greater probability for the occurrence of detached sandstone units and up-dip seals (Brownfield and Charpentier, 2006).

2.2.2 Seismic Data Analysis-Principles of Stratigraphic

Interpretation

Seismic stratigraphy is a technique for interpreting stratigraphic information from seismic data. The seismic reflection resolution follows gross bedding and as such, approximates time lines (i.e. the contrast represented on seismic lines comes from the bedding surface and not from lateral variations). Understanding the image resolution is thus very important in seismic data (UPRM, 2015). Figures 2.3 - 2.7 were obtained from a power point presentation delivered by the geology department of the University of Puerto Rico, Mayagüez campus (UPRM). Figure 2.3 shows the degree of vertical and horizontal variation of facies in the bedding.

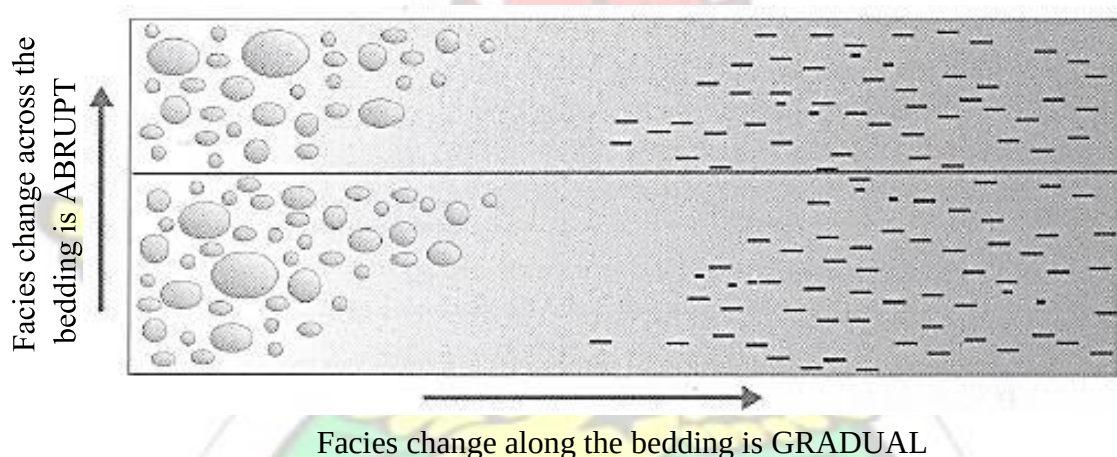


Figure 2.3 *Facies variation along and across bedding (UPRM, 2015)*

In addition to bed thickness constraints, three other factors limit the final resolution of the seismic data:

1. The Earth acts as a filter that progressively attenuates the high-frequency components of the seismic data (UPRM, 2015).
2. Acoustic velocity increases with depth due to compaction and increased cementation. This increases the wavelength of the signal with detrimental effect on the resolution (UPRM, 2015).

3. If there is high ambient noise on the raw data, the processing stream may include a high-cut filter which has the effect of removing the high frequency necessary for finer resolution (UPRM, 2015).

For stratigraphic interpretation, the first step is to determine the vertical and horizontal scale of the seismic section, and find out from the section header whether the data has been migrated, and whether it is marine or land data. The next step is to divide the seismic data into discrete natural stratigraphic packages that make up the section. This is done by identifying and marking reflection terminations. It is a good idea to ignore zones of broken or chaotic reflections and concentrate on better data. They can be interpreted later. When reflections terminate in a consistent manner they define a line on the seismic section/surface (UPRM, 2015).

The key surface that divides stratigraphy into component system tracts are transgressive surfaces, sequence boundaries, maximum flooding surfaces and marine onlap/downlap surfaces between the lowstand fans and the lowstand wedge. Sequence boundaries on seismic data can be recognized from the development of a high relief truncation surface (particularly one that erodes the topsets of older units), and by a downward shift of coastal onlap across the boundary. Figure 2.4 and 2.5 show how a seismic surface can be divided into stratigraphic packages by examining reflection terminations (UPRM, 2015).

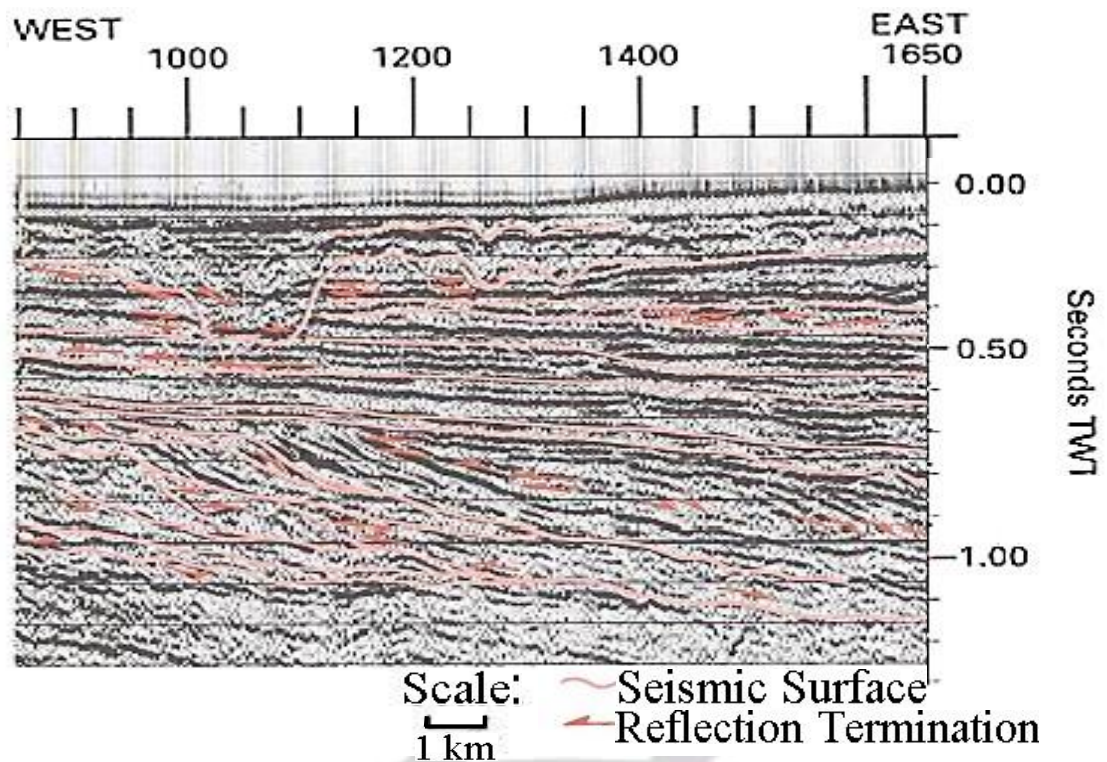


Figure 2.4 Seismic section showing reflection terminations (UPRM, 2015)

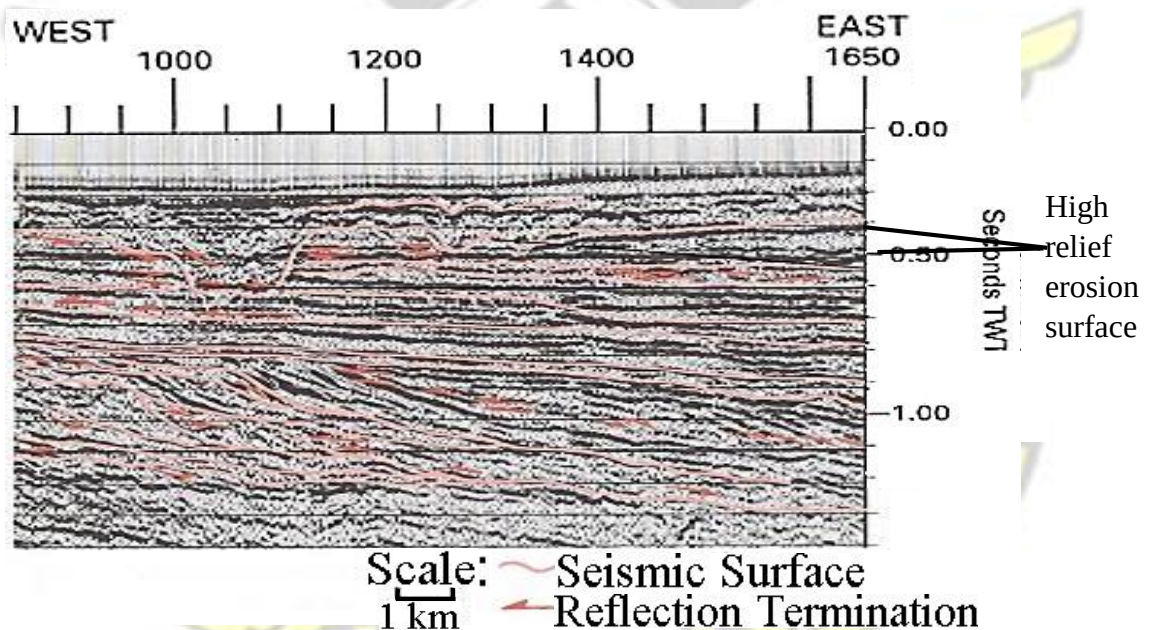


Figure 2.5 Seismic sequence boundaries (UPRM, 2015)

The proximal onlap of topset reflections is the coastal onlap. It is formed at or near sea-level during shallow marine processes. A downward shift in coastal onlap implies a fall in relative sea-level, accompanied by subaerial exposure and erosion over the

topset area. In Type 1 sequence boundaries the topset reflections onlap an older clinoform. In Type 2 they onlap onto an older topset boundary. Figure 2.6 shows a type 1 sequence boundary (UPRM, 2015).

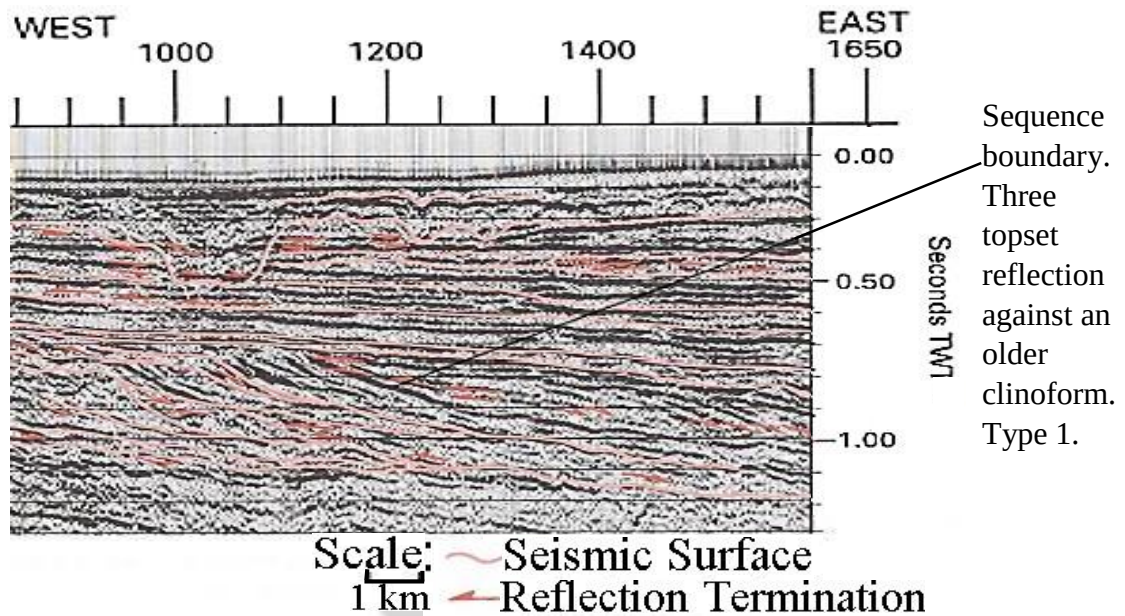


Figure 2.6 Seismic surface showing Type 1 sequence boundary (UPRM, 2015)

A transgressive surface marks the end of lowstand progradation, and the onset of transgression. It need not be associated with any reflection terminations, but will mark the boundary between a topset-clinoform interval and an interval of only topsets.

Figure 2.7 shows the sequence boundary for various seismic surfaces (UPRM, 2015).

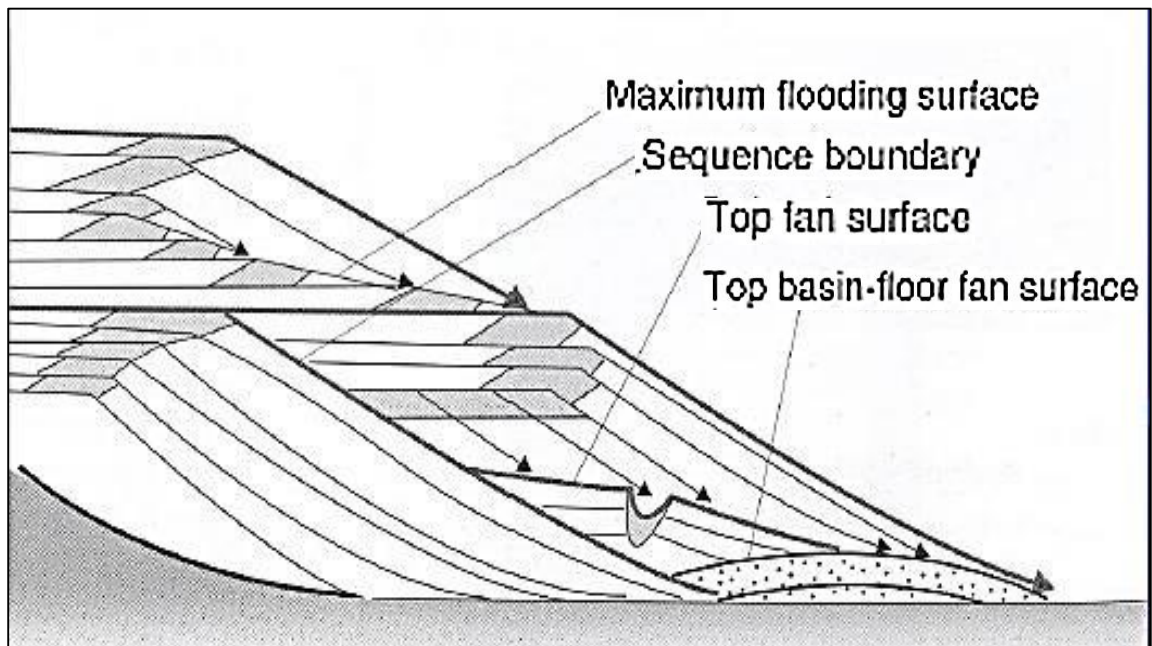


Figure 2.7 Image showing seismic surfaces within a sequence (Source, UPRM)

2.2.3 Seismic Attributes and Attribute Mapping

A seismic attribute is the quantity derived from seismic data that can be analysed to improve the information strength. It leads to the improvement of the geological or geophysical interpretation of the data. Seismic attributes can be classified as either physical attributes or geometric attributes. Physical attributes are directly related to the lithology, wave propagation and other parameters, and can be further classified as pre-stack and post-stack attributes. Geometric attributes are dip, azimuth and discontinuity, which make it easier to view faults on horizons (Ahmed, 2014).

Examples of physical seismic attributes are frequency, attenuation, amplitude, measured time and the combination of several of these. Most of the seismic attributes

are post-stack, but those that use CMP gathers (such as amplitude versus offset) must be analysed before stacking (pre-stack.) (Ahmed, 2014).

The first set of attributes that was developed was called the one dimensional (1D) complex seismic trace. It included the instant frequency, apparent polarity, envelope amplitude and the instantaneous phase attributes. The acoustic impedance that was derived from the seismic inversion method is also counted as one of the attributes in this set. The other attributes developed later are the azimuth, coherence, dip, instantaneous bandwidth, amplitude versus offset (AVO), spectral decomposition, response amplitude and response phase attributes (Ahmed, 2014).

Another group of seismic attributes which are able to indicate the absence or presence of hydrocarbon indicators was also introduced and named Direct Hydrocarbon Indicators (DHIs). These are Bright spots, flat spots, dim spots and polarity reversals. All these attributes rely on the seismic signal amplitude as the basis for their computation (Ahmed, 2014).

According to Ahmed, (2014), the other types of attributes include:

Mean Amplitude: This post-stack attribute calculates the arithmetic average of the amplitudes of a trace within a specified window. It is applied in the detection of trace bias which could be indicative of a bright spot.

Average Energy: This attribute calculates the sum of the squared amplitudes divided by the number of samples within the specified window used. It provides a measure of reflectivity and helps to map direct hydrocarbon indicators within a zone of interest.

RMS (root mean square) Amplitude: This post-stack attribute evaluates the square root of the sum of squared amplitudes, divided by the number of samples within the specified window chosen. It enables reflectivity measurements and makes it possible

to directly map hydrocarbon indicators. The attribute is quite sensitive to noise- as it squares every value within the window.

Maximum Amplitude: This post-stack attribute calculates the highest value of the amplitudes in the window of interest and is hence used to map the strongest hydrocarbon indicators

AVO Attributes: These pre-stack attributes measure the variation in seismic amplitude with varying offset and can thus be used to predict a reservoir's property at a greater distance from the drilled well. Variations include the AVO intercept, AVO gradient, AVO intercept x gradient, AVO fars – nears and fluid factor, among others.

Anelastic Attenuation Factor (Q): This attribute is determined from seismic reflection data and is used for advanced seismic processing and reservoir characterisation.

Time / Horizon Attributes

Coherence: This post-stack attribute measures the continuity between seismic traces in a specified window along a picked horizon. It enables the mapping of the lateral extent of a formation. It can also be used to see discontinuous features such as faults and channels. Coherence is computed along arbitrary time-slices along a specific horizon with the help of software packages (Ahmed, 2014).

Dip: This post-stack attribute computes the best line of fit in a 2D or 3D plane for each trace between its immediate neighbour traces on a horizon. The output generated is the magnitude of dip (gradient) of the line or plane, in degrees. This attribute can be created on a horizon slice with the help of a pseudo paleo-geologic map (Ahmed, 2014).

Azimuth: This post-stack attribute computes the best fit plane between each trace and its immediate neighbour traces on a horizon. The output is in the form of the direction of maximum slope (i.e. the dip direction), measured in degrees clockwise from the

north direction. The azimuth attribute thus differs from the geological azimuth which is measured 90 degrees counter-clockwise from the dip direction (i.e. the strike direction) (Ahmed, 2014).

Curvature: This represents a group of post-stack attributes that are calculated from the curvature of a specified horizon. The constituent attributes are the magnitude/direction of maximum and minimum curvatures, the magnitude of a horizon's curvature along the azimuth (dip) direction, the magnitude of a horizon's curvature along the strike direction, and the magnitude of a contour line's curvature along a horizon.

Attribute mapping simply involves the demonstration of reservoir properties in a plan-view projection of seismic attributes, in order to promote optimal field development. Attribute maps are used for well placements, reserve calculations and reservoir performance monitoring. Attribute mapping is a part of reservoir characterisation and hence depends on the expert's working knowledge in applied geologic models.

Attribute maps can be generated from 2D or 3D data depending on whether the surface or volume of an area of interest is being investigated. Examples of volumetric (3D) seismic attributes are *VatMAV*, *Vatsum*, *VatABS* and *Vatrms* (where the *vat-* prefix stands for volumetric attribute) (Ahmed, 2014).

2.2.4 Extended Elastic Impedance

The Elastic inversion of pre-stack seismic data yields two reliable elastic properties. These are Shear impedance (SI) or equivalently (V_p/V_s), and acoustic impedance (AI). The combination of these two enable the generation of several attributes which can be used to discriminate fluids and lithologies. An alternative approach combining the Gradient Impedance (GI) and AI through a log-log coordinate rotation was later introduced by Whitcombe et. al (2002) and called the Extended Elastic Impedance

(EEI).

The EEI approach was introduced to improve the limitation on the Elastic Impedance theory for rock property prediction. The limitation involves the inability for rock property predictions to be made from existing seismic data due to the restrictions on the angles of incidence. The EEI method thus enables the projection of seismic amplitudes to angles of incidence outside of the recorded angles (from 0 to 30 degrees and from -90 to 90 degrees (Hicks and Francis, 2006). This in turn makes it possible to express rock properties in terms of impedance values. By doing some correlation and projection into certain angles called Chi angles, the EEI can be conditioned towards the prediction of fluid or lithological properties of rocks (for rock properties associated with higher angles).

The EEI method is carried out to generate several seismic attributes (LMR, water saturation, bulk modulus, V_P / V_S , Poisson's ratio etc.). Comparisons of these help to determine the sensitivity of elastic parameters to seismic anomaly, improve reservoir characterization and enhance fluid and lithology imaging (Shahri, 2013) .

A relationship between reservoir properties and the EEI can be investigated by correlation analysis- as a function of the new angle (Chi)- between EEI logs and available petrophysical logs such as porosity, volume of

shale, saturation,
gamma ray and
lithology logs. Once the
optimum Chi angle is
determined, the AVO
analysis is carried out
to obtain intercept and
gradient attributes, and
their linear combination
allows the
determination of the
reservoir properties
(Hermanal et al., 2012).

The Concept of EEI can be derived from two-term AVO equation (Hicks & Francis, 2006) as follows:

$$R(\theta) = A + B\sin^2(\theta) \dots\dots\dots 2.1$$

Where A = intercept

B = gradient

θ = Chi angle

R

= Reflectivity

The equation above is a two-term linearization of the Zoeppritz equation for reflectivity (Aki and Richards, 1980).

The Whitcombe aspect of this equation involves the replacement of $\sin^2(\theta)$ by $\tan \chi$.

Equation 2.1 therefore becomes equation 2.2, which allows the angle to vary from -90° to $+90^\circ$, i.e.:

$$R(\chi) = A + B \tan(\chi) \dots\dots\dots 2.2$$

Scaling this equation by $\cos(\chi)$, the scaled reflectivity can be obtained from:

$$R_s(\chi) = A \cos(\chi) + B \sin(\chi) \dots\dots\dots 2.3$$

When R_s goes to zero, the relationship between AVO attribute with rotation angle can be calculated from:

$$\tan(\chi) = - \frac{A}{B} \dots\dots\dots 2.4$$

Where χ = minimum energy.

Verma and Biswal (2011), and Hicks et al. (2006) refer to the angle χ as “minimum energy χ ” at which the reflectivity defined by the two-term AVO equation is zero. It is the angle at which the trend line in an AVO cross plot subtends to the negative B axis.

The equivalent expression for Equation 2.3 as EEI is:

$$EEI(\chi) = \alpha_o \rho_o \left[\left(\frac{\alpha}{\alpha_o} \right)^p \left(\frac{\beta}{\beta_o} \right)^q \left(\frac{\rho}{\rho_o} \right)^r \right] \dots\dots\dots 2.5$$

where α = P-wave velocity
 ρ = density
 β = S-wave velocity
 $p = \cos \chi + \sin \chi$,
 $q = -8K \sin \chi$, $r = \cos \chi - 4K \sin \chi$ α_o , β_o , and ρ_o are the averages of the respective property used as normalization factors for P velocity, S velocity, and density respectively. K is the average of $(V_s/V_p)^2$.

The correct application of this method requires the estimation of reliable AVO attributes which are affected by several data pitfalls such as and among others, unbalanced amplitude spectra through offset. Heavy seismic pre-conditioning is necessary to overcome these issues which, in turn, are managed more efficiently in

available elastic inversion algorithms by the use, for instance, of multiple offsetvarying wavelets (Shahri, 2013).

Figure 2.10 was taken from a PowerPoint slide presented by ARCIS Seismic Solutions Corp., a Canadian company. It shows sample EEI inversion results for bulk modulus at the top (K), Young's modulus in the middle (E), and Volume of shale attributes at the bottom (GR). A good lithology and porosity variation can be interpreted considering both bulk modulus and Young's modulus. The middle part of the Volume of shale's zone of interest is showing a high volume of shale, as was expected during the investigation.

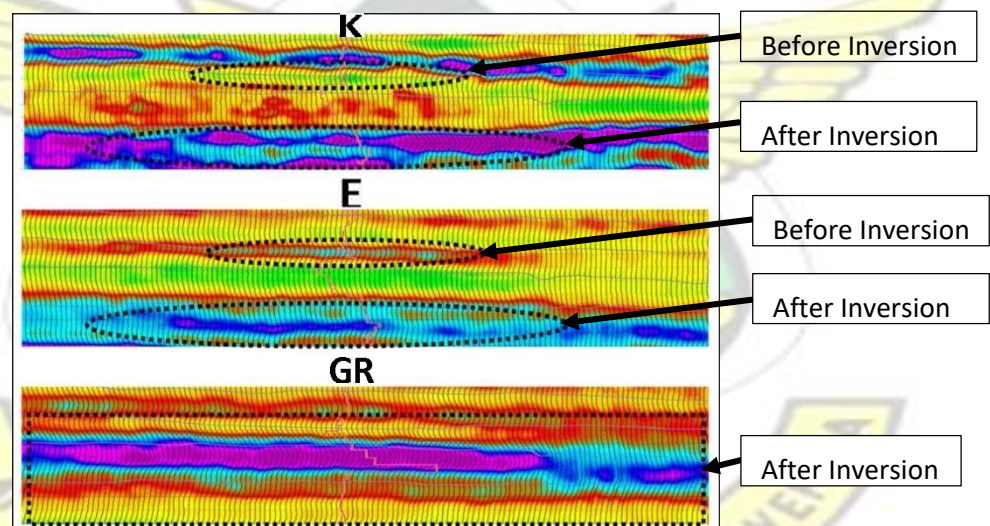


Figure 2.8 Illustration of how EEI inversion fine-tunes the data (ARCIS,2016)

2.2.5 Well Logs, Synthetic Seismograms and Ties to Seismic

In order for well data (which is in units of depth) to be compared to seismic data (which is in units of time), well-seismic ties are often applied. They enable the linking of horizon tops identified in the well to specific reflections on the seismic section. This is achieved through the generation of a synthetic seismic trace from sonic and density well logs and subsequently, the comparison of the generated trace to the real seismic data obtained near the well location (Schroeder, 2002). Figure 2.9 is an example of a well-seismic tie and consists of the superposition of the well data directly on the seismic section.

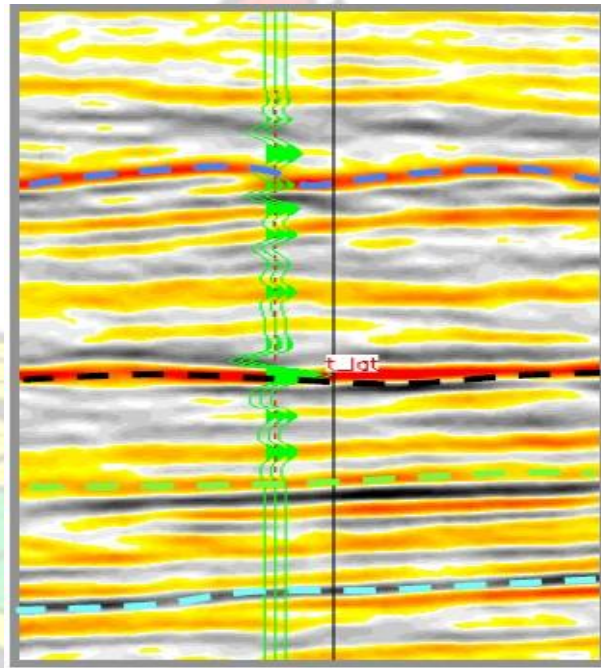


Figure 2.9 An example of a well log to seismic tie (Schroeder, 2002)

There are several differences between seismic data and well data. In order to understand how they can be tied together, it is important to understand the

interrelationship between both data sets. Table 2.1 outlines the differences between seismic and log data.

Table 2.1 Comparison between seismic and well log data (Schroeder, 2002)

Seismic Data	Well Data
Time measurement	Depth measurement
Samples area and volume	Samples point along well bore
Low frequency 5 - 60 Hz	High frequency 10 000 – 20 000 Hz
Vertical resolution 15 – 100 m	Vertical resolution 2 cm – 2 m
Horizontal resolution 150 – 1000 m	Horizontal resolution 0.6 cm – 6 m
Measuring seismic amplitude, phase, continuity, horizontal & vertical velocities	Measures vertical velocity, density, resistivity, radioactivity, SP, rock and fluid properties from cores

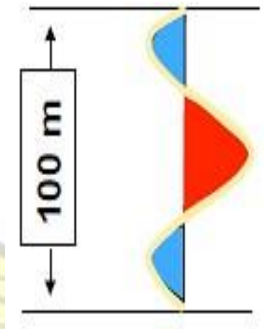


Figure 2.10 Time measurement
(Schroeder, 2002)

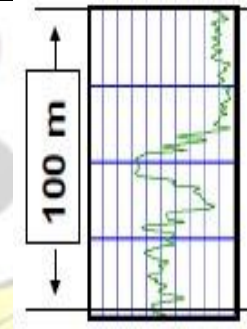


Figure 2.11 Depth measurement
(Schroeder, 2002)

Figure 2.10 and 2.11 show the difference between time and depth measurement.

In tying synthetic seismograms to seismic data, the reference datum chosen for the synthetic trace is usually ground level or the seismic datum. In the absence of check shot data, the start time estimation of the first bed should be used instead. The synthetic trace should be shifted in time to get the best tie (Figure 2.12 and 2.13). The stratigraphic information from a detailed plot can be used to determine the best fit.

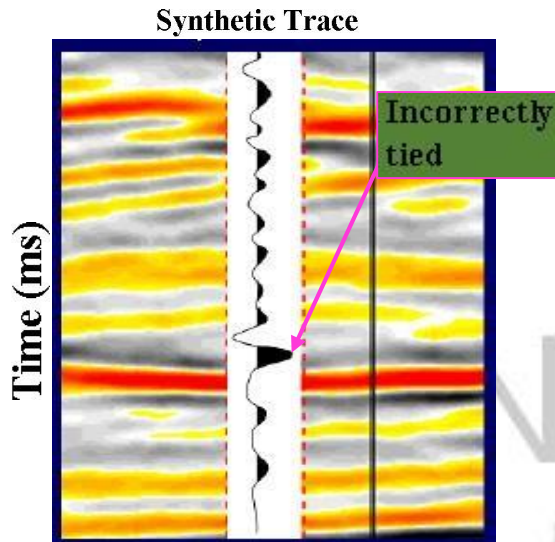


Figure 2.12 Position of seismic trace before tie (Schroeder, 2002)

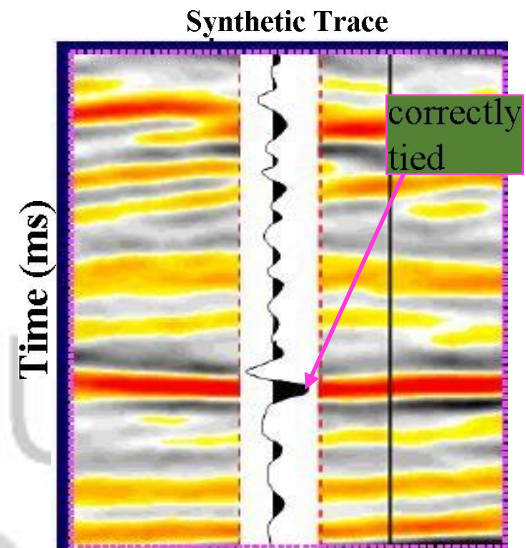


Figure 2.13 Position of seismic trace after tie (Schroeder, 2002)

If justified, the trace may be shifted laterally by several traces to get the best character tie (Figure 2.14), as character tie is more important than time tie. A cross-correlation coefficient can be used to measure the quality of the character tie. The tie that yields the best character with the least time shift in the zone of interest (Figure 2.15) would be the optimum choice. The blue arrow in Figure 2.14 shows how a trace may be shifted laterally to obtain the best character tie.

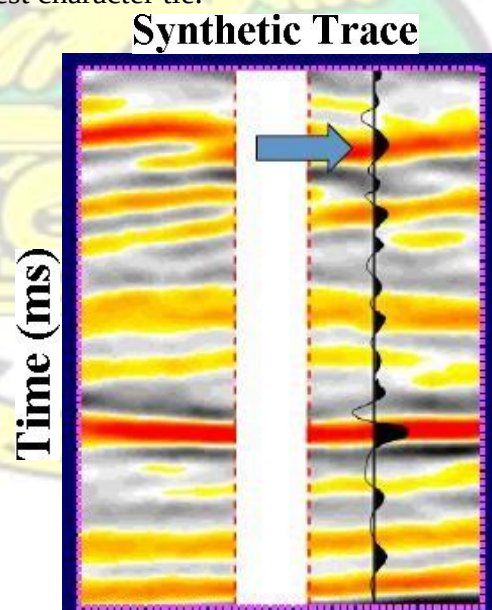


Figure 2.14 Lateral shift of seismic trace (Schroeder, 2002)

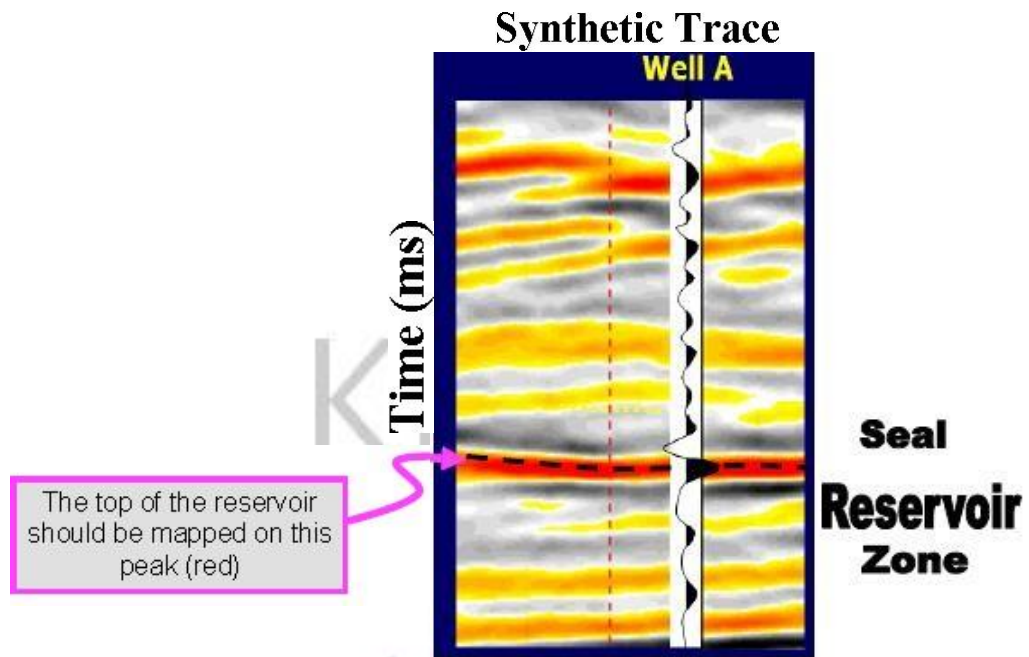


Figure 2.15 Best tie with least time shift (Schroeder, 2002)

2.2.6 Well Logs

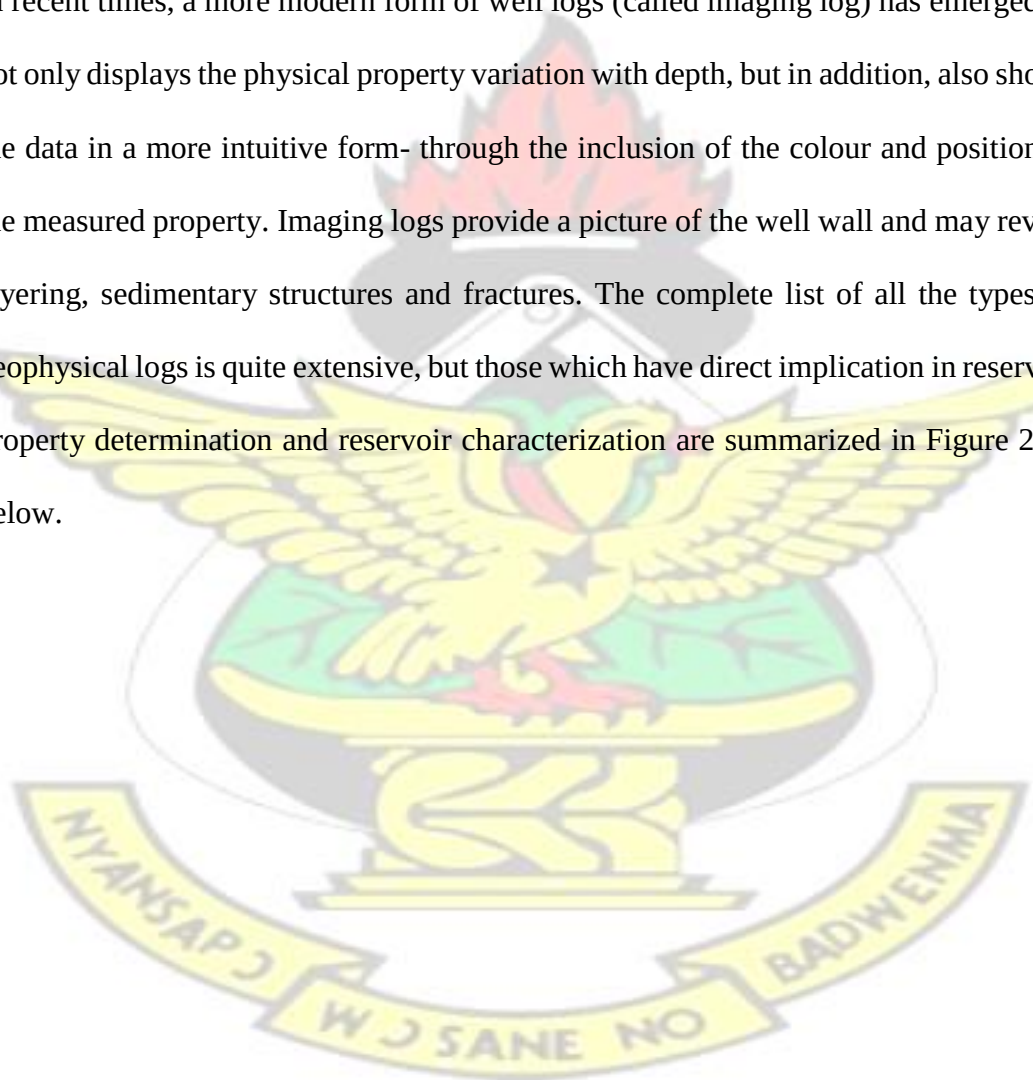
Well logging is the process of continuously recording physical, electrical, chemical or other properties of the fluid or rock mixtures which have been penetrated by a borehole drilled into the earth's crust. It facilitates reservoir identification, the estimation of the hydrocarbon in place and the determination of the amount of hydrocarbon that is recoverable. Well logs can be described as a graphical representation of well logging results. Their measurements occupy a position of central importance in the life of a well, between two milestones: surface seismic survey- which has influenced the decision for the well location, and production testing (Shahnawaz, 2012). Both enable the direct measurements of several parameters such as:

1. The electron density of the rock
2. The resistivity at various distances from the borehole of the rock
3. The acoustic travel-time of the rock
4. The neutron absorption rate
5. The self-potential of the rock/borehole fluid interface
6. The flow rate and density of fluids in the wellbore
7. The size of the borehole drilled in the rock
8. Other related or derived properties

The measured properties above can subsequently be used to:

1. Identify the productive zones of hydrocarbons
2. Define petrophysical parameters such as porosity, permeability, hydrocarbon saturation and lithology etc.
3. Determine the depth, pressure, formation temperature and reservoir thickness
4. Measure the hydrocarbon mobility
5. Distinguish between oil, water and gas zones in the reservoir

In recent times, a more modern form of well logs (called imaging log) has emerged. It not only displays the physical property variation with depth, but in addition, also shows the data in a more intuitive form- through the inclusion of the colour and position of the measured property. Imaging logs provide a picture of the well wall and may reveal layering, sedimentary structures and fractures. The complete list of all the types of geophysical logs is quite extensive, but those which have direct implication in reservoir property determination and reservoir characterization are summarized in Figure 2.16 below.



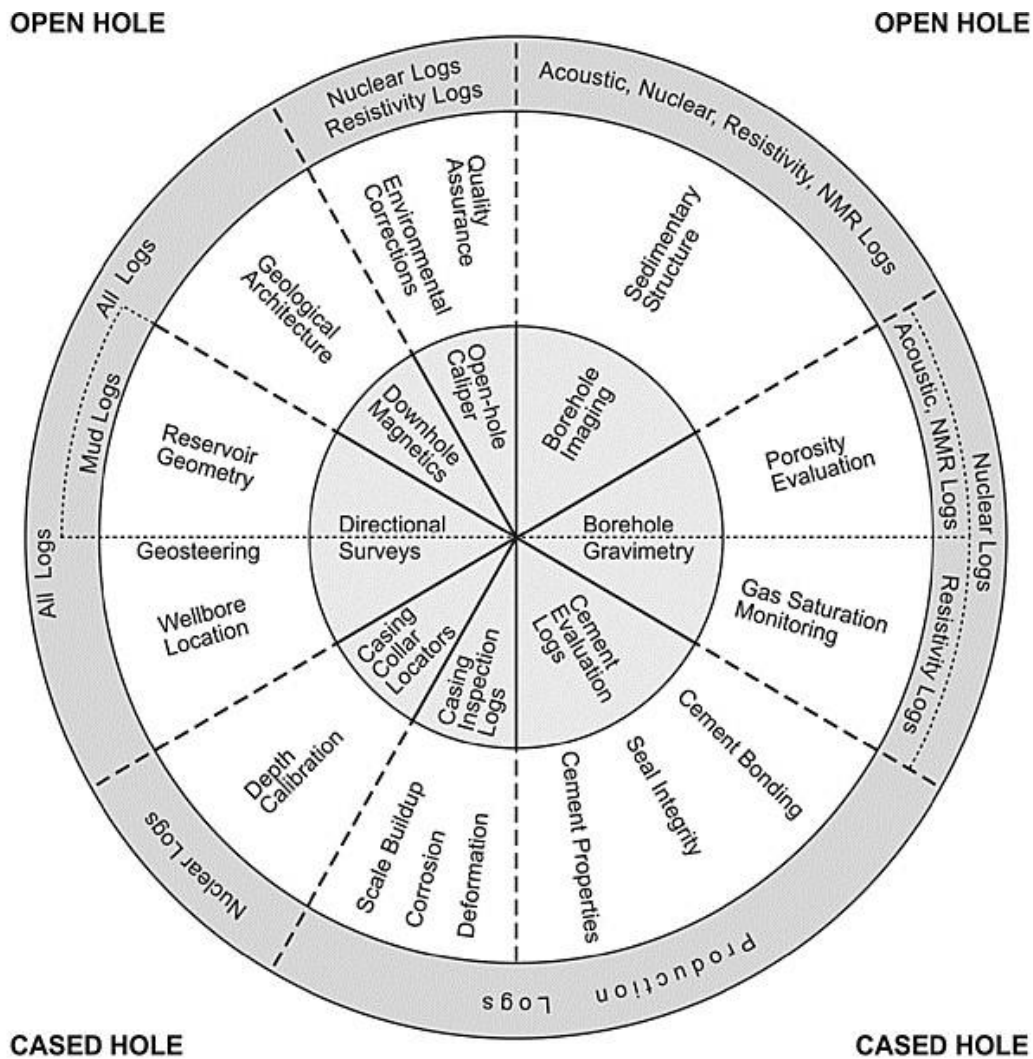


Figure 2.16 Summary of a number of specialized logging methods related to reservoir characteristics and the properties they measure (Wireline Logs, 2014)

Figure 2.16 is separated into three concentric areas: The innermost area which represents the specialized logging tools, the middle annular area which shows the subsurface properties that are to be evaluated, and the outermost area which indicates the types of logs that can be used to evaluate those properties. Table 2.2 summarises all the logs that are directly associated with reservoir property prediction and outlines what they are used for.

Table 2.2 The functions of logs in petrophysical and rock physics properties analysis (Ijassan et al., 2013)

Name	Uses
------	------

Gamma Ray (GR)	Lithology interpretation, shale volume calculation, calculating clay volume, permeability calculation, porosity calculation, wave velocity calculation, etc.
Spontaneous Potential (SP)	Lithology interpretation, R_w and R_{we} calculation, detecting permeable zone etc.
Caliper (CALI)	Detecting permeable zone, locating a bad hole
Shallow Resistivity (LLS and ILD)	Lithology interpretation, finding hydrocarbon bearing zone, calculating water saturation, etc.
Deep Resistivity (LLD and ILD)	Lithology interpretation, finding hydrocarbon bearing zone, calculating water saturation, etc.
Density (RHOB)	Lithology interpretation, finding hydrocarbon bearing zone, porosity calculation, rock physics properties (A_l , S_i , σ , etc.) calculation, etc.
Neutron Porosity (NPHI)	Finding hydrocarbon bearing zone, porosity calculation, etc.
Sonic (DT)	Porosity calculation, wave velocity calculation, rock physics properties (A_l , S_i , σ , etc.) calculation, etc.
Photoelectric (PEF)	Mineral determination (for lithology interpretation)

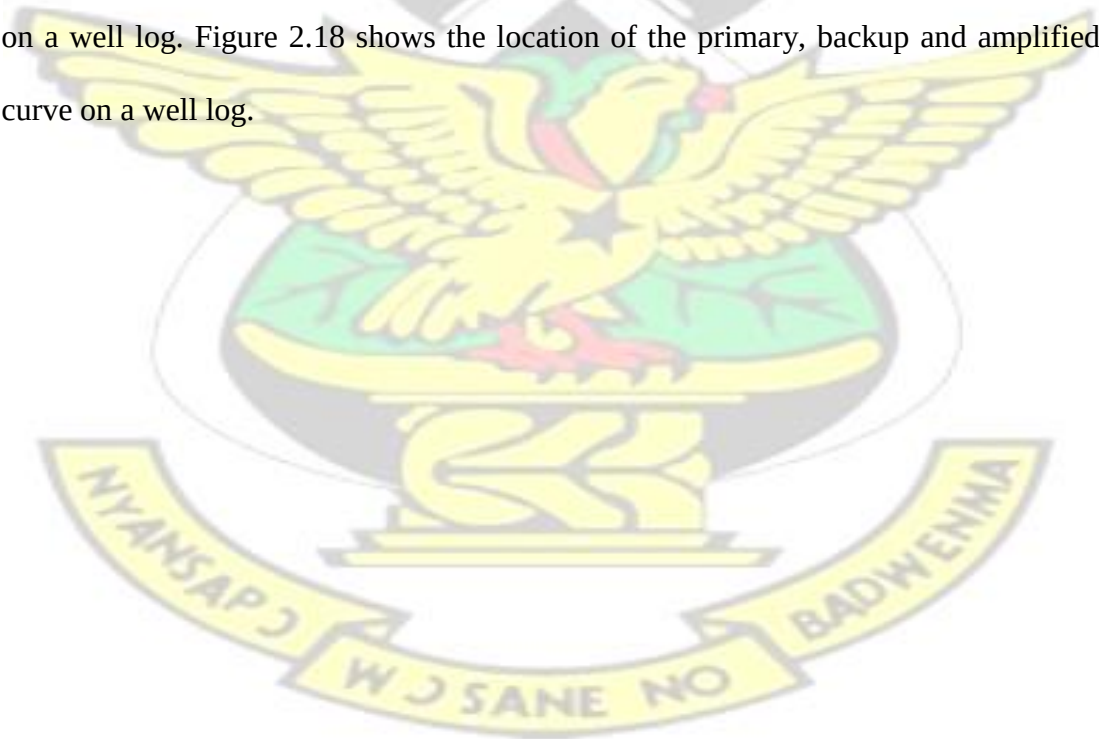
2.2.6.1 How to Read Log Tracks

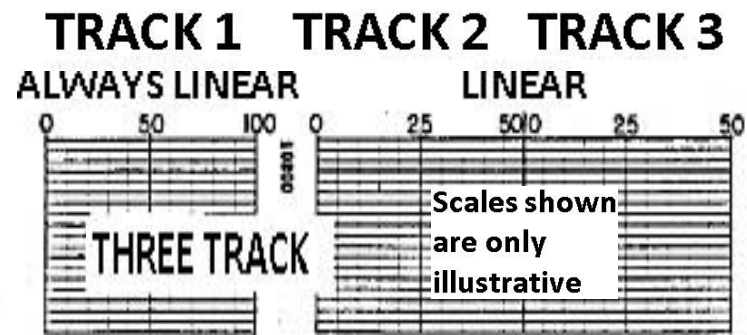
Log tracks can be run on a variety of vertical and horizontal scales but the vertical axis always represents depth whilst the horizontal axis represents the magnitude of the measured parameter. The inter-gridline spacing for the depth axis is usually about five metres (10 feet) for correlation scales and 1 metre (2 feet) for other scales. The linear scale on logs can be of any range and it is therefore important to check every time to know the scale of the log section being analysed (Crain, 2015).

Back-up scales are positioned on the log header beneath the primary scale. They are meant to take over whenever the primary curve goes off-scale. They may be of the

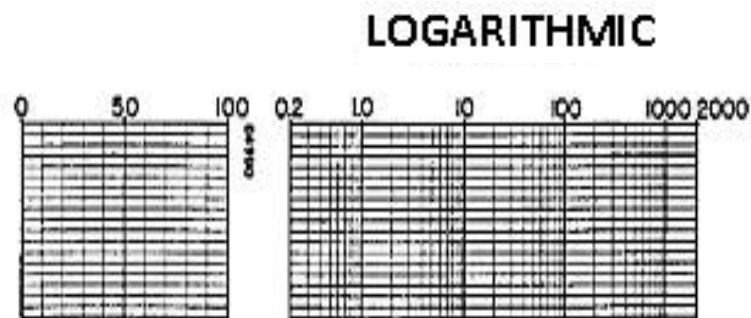
same sensitivity (e.g. 120 - 220 is the backup-scale to a 20 – 120 scale) or a multiple of the primary scale (e.g. 0 - 400 is the back-up scale to a 0 - 40 scale). Most often, the multiple is 10 to 1 and the first one tenth of the back-up scale is blanked out to prevent confusion. A log can have multiple back-ups, giving a considerable range of answers in the event that the wrong scale is selected for interpretation (Crain, 2015).

Amplified scales are often presented on sonic or resistivity logs. For the former for example, an amplified scale of 40 - 80 or 40 - 100 can be used for a primary scale of 40 - 140. For the latter, the short normal curve may be amplified on a 0 - 2 or 0 - 4 scale for a primary scale of 0 - 20 or 0 - 50. Amplified scales are not used on metric sonic logs or logarithmic presentations, as their scales usually provide sufficient detail (Crain, 2015). Figure 2.17 shows the different scales combinations that may be found on a well log. Figure 2.18 shows the location of the primary, backup and amplified curve on a well log.





**Scales shown
are only
illustrative**



SPLIT

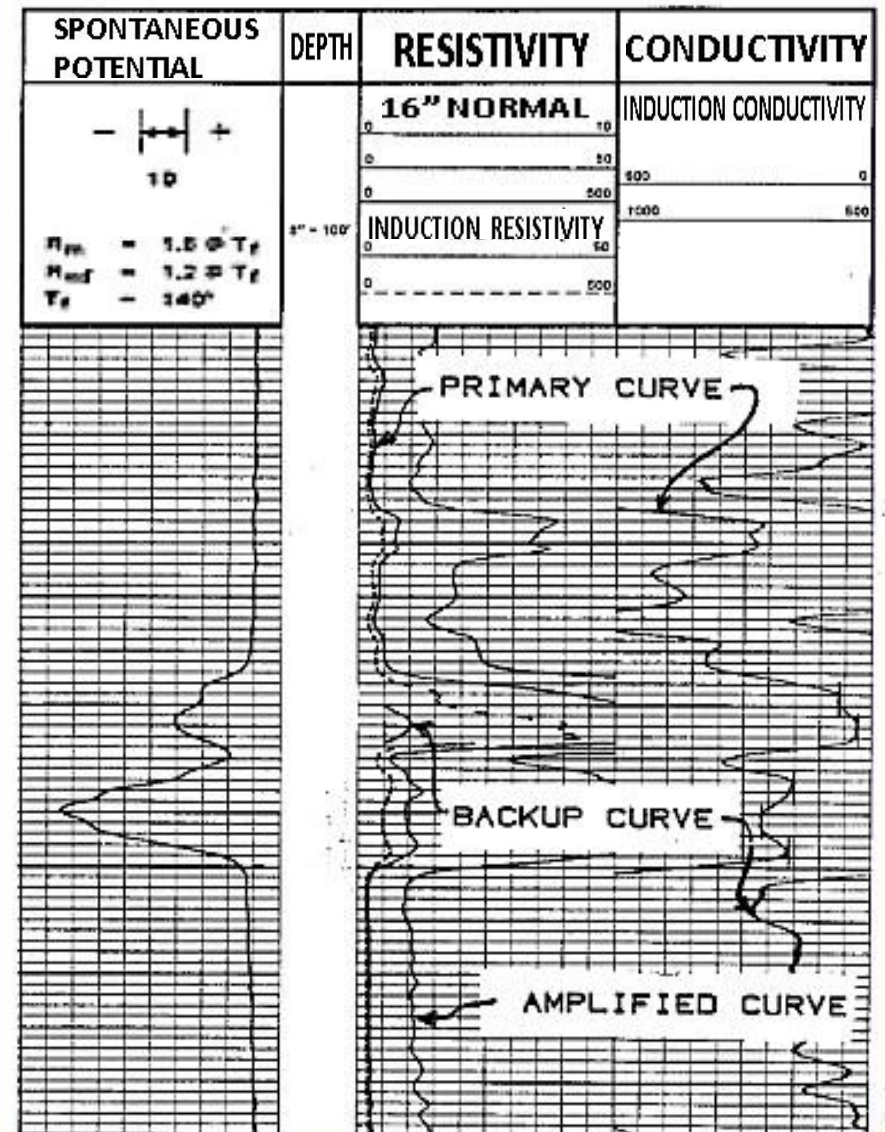
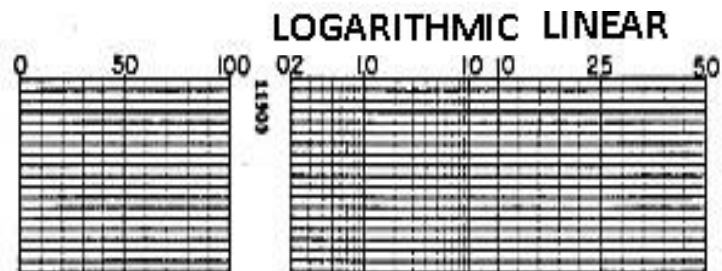


Figure 2.17 Various log grid styles (Crain, 2015)

³⁷ **Figure 2.18** Primary, backup and amplified log curves (Crain, 2015)



There are many different variations of well log presentations. Modern logs often appear in the form of a three track presentation with the second and third track being collectively called track four. Track four is employed when there is a need to record curves with large range values (Crain, 2015).

The Atlas of Log Response Chart is one of the tools that may be used in interpreting log curves. It is very resourceful but requires a simultaneous mental assessment of five or six log curves. This may prove tough for novice analysts and even the more experienced professionals are occasionally susceptible to error. Figure 2.19 is an Atlas of log responses chart provided by Baker Hughes (Hughes, 2002). It is important to note that the chart has been split into 3 horizontal sections (2.19 (a), 2.19 (b) and 2.19 (c)) over three pages to enhance legibility. Although there are many alternative ways of interpreting log curves, all methods are governed by general rules which will be briefly explained below.

The first step in reading log tracks is to identify the log curves available and determine their scales. In most cases, each log curve has a particular response typical to the particular medium or lithology it is passing through. The depth track (space where all depth numbers are printed) is often used for annotation of tops, core data and DST. In order to read and interpret log tracks accurately, the typical behaviour of each log track in response to its environment must be known. Figure 2.20 is the legend for the Atlas of log chart.

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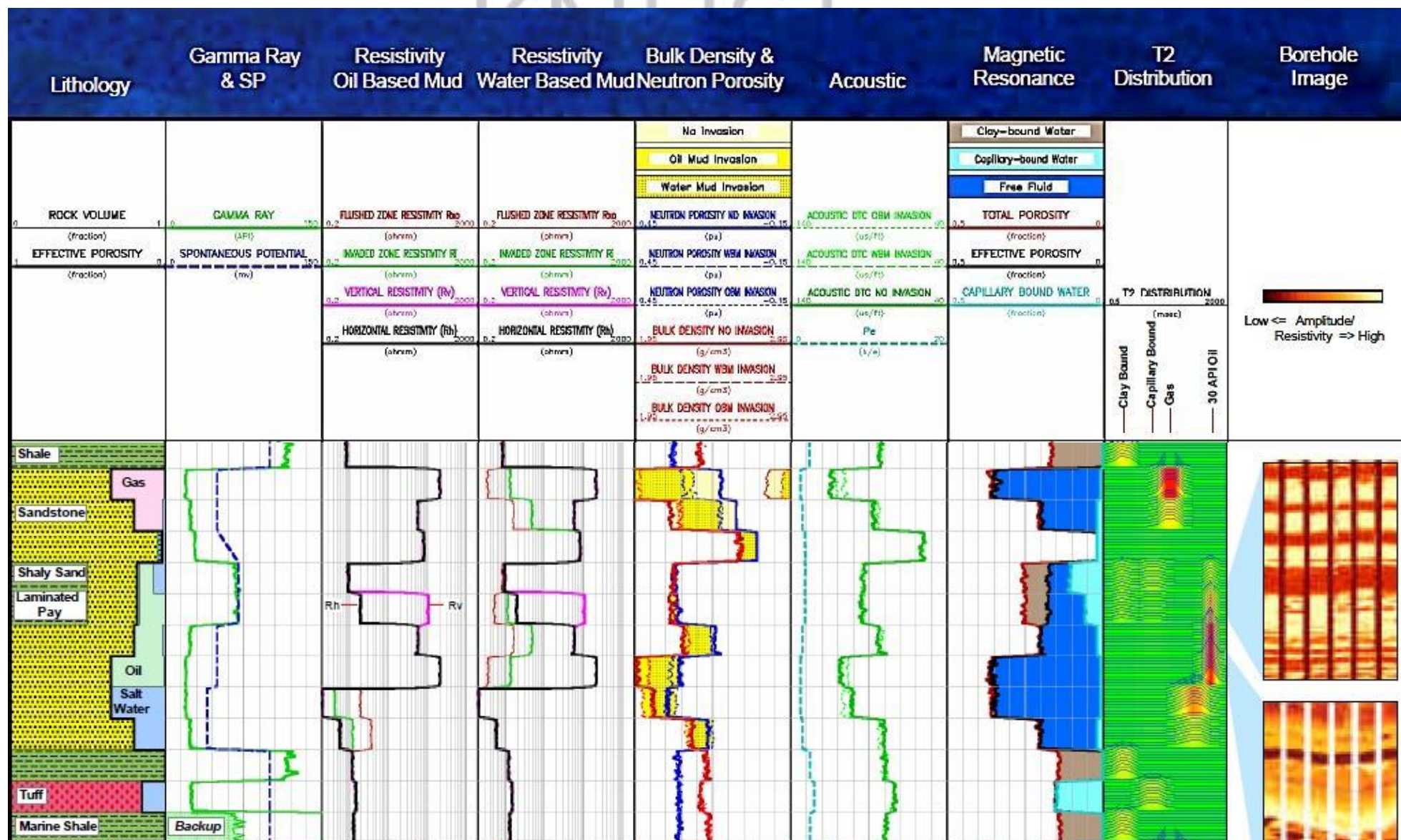


Figure 2.19 (a) Atlas of log responses chart (Hughes, 2002)



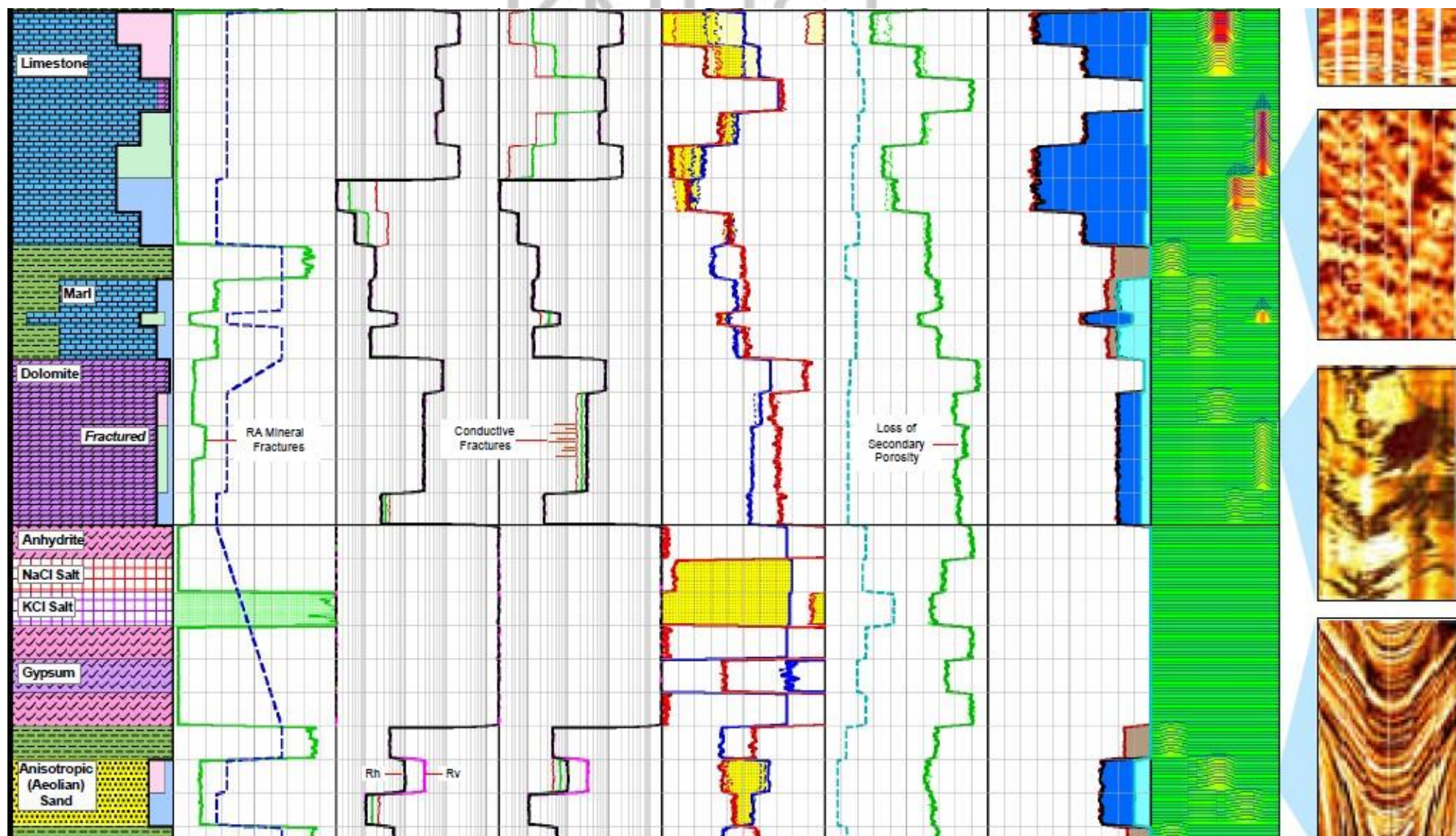
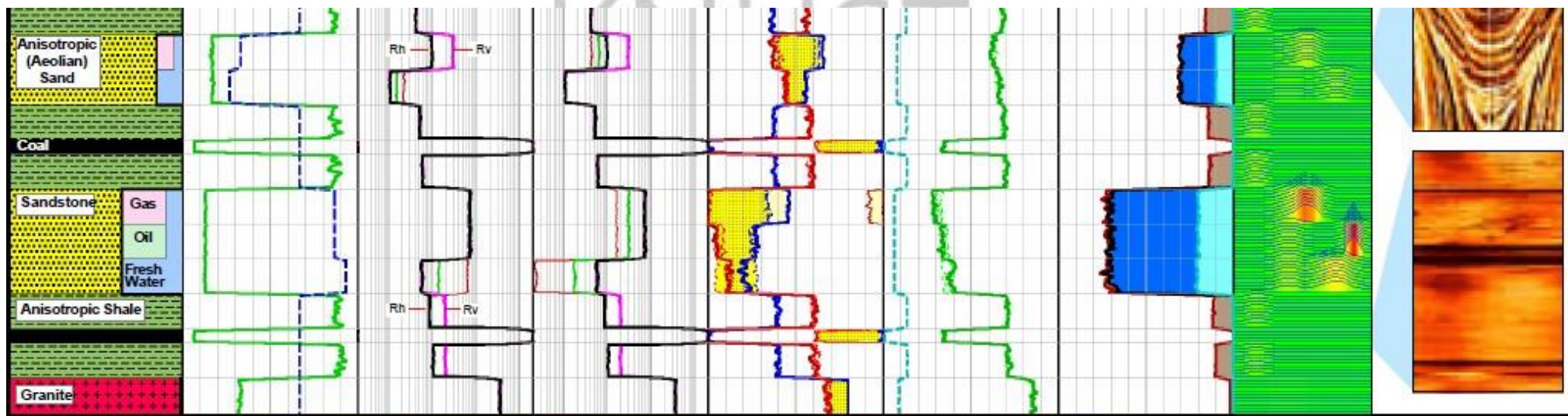


Figure 2.19 (b) Atlas of log responses chart (Hughes, 2002) **Figure 2.19 (c)** Atlas of log responses chart (Hughes, 2002)





Lithology		GR	Density	Neutron	Acoustic	Resistivity	PE
Sandstone		Low (Unless RA min)	2.65	-4	53	High	1.81
Limestone		Low	2.71	0	47.5	High	5.08
Shale		High	2.2-2.7 (water content)	High (water content)	50-150 (water content)	low (water content)	1-5
Dolomite		Low (higher if U)	2.87	+4	43	High	3.14
Anhydrite		V.Low	2.98	-1	50	V.High	5.06
Salt		Low (Unless K salt)	2.03 (1.87)	-3 (-2)	67 (74)	V.High	4.65
Water		0	1-1.1 (salt & temp)	100	180-190	0 - infinite (salt & temp)	0.36 (+salt)
Oil		0	0.6-1.0 (api)	70-100 (H2 index)	210-240 (api)	V.High	Low
Gas		0	0.2-0.5 (pressure)	10-50 (H2 index)	~1000	V.High	Low

Figure 2.20
General log
matrix
(Hughes,
2002)

Gamma Ray log track

Gamma ray logs measure the natural radioactive emissions of gamma rays from the rock formations in the well. The ray intensity in gamma logs is a function of the initial gamma ray emission intensity (which is a property of the elemental composition of the rock), the amount of Compton scattering that the gamma rays encounter (which is related to the distance between the ray emission and detector), and the density of the intervening material. The tool therefore has a limited depth of investigation (Hancock, 1993).

Often thought of as a grain size profile, the gamma log can be readily interpreted alone in most zones, and readily correlated with other information pertaining to the formation type- since formations generally have a characteristic curve response depending on the formation type. Gamma logs are strongly affected by highly radioactive formations but not by the formation fluid or changes in borehole diameter. They can therefore not represent permeability or porosity. The gamma log track generally appears similar to the SP log track. The highest curve value is usually indicative of shale and all log recordings are always positive (There is no base/zero line). There are three basic types of shapes that can be identified on the gamma log. These are the funnel shape (coarsening upwards), the cylinder shape (blocky) and the bell shape (finning upward) all of which are displayed in Figure 2.21.

These three shapes can further be subdivided into either smooth (or relatively homogeneous), and serrated (with interbedded thin shales).

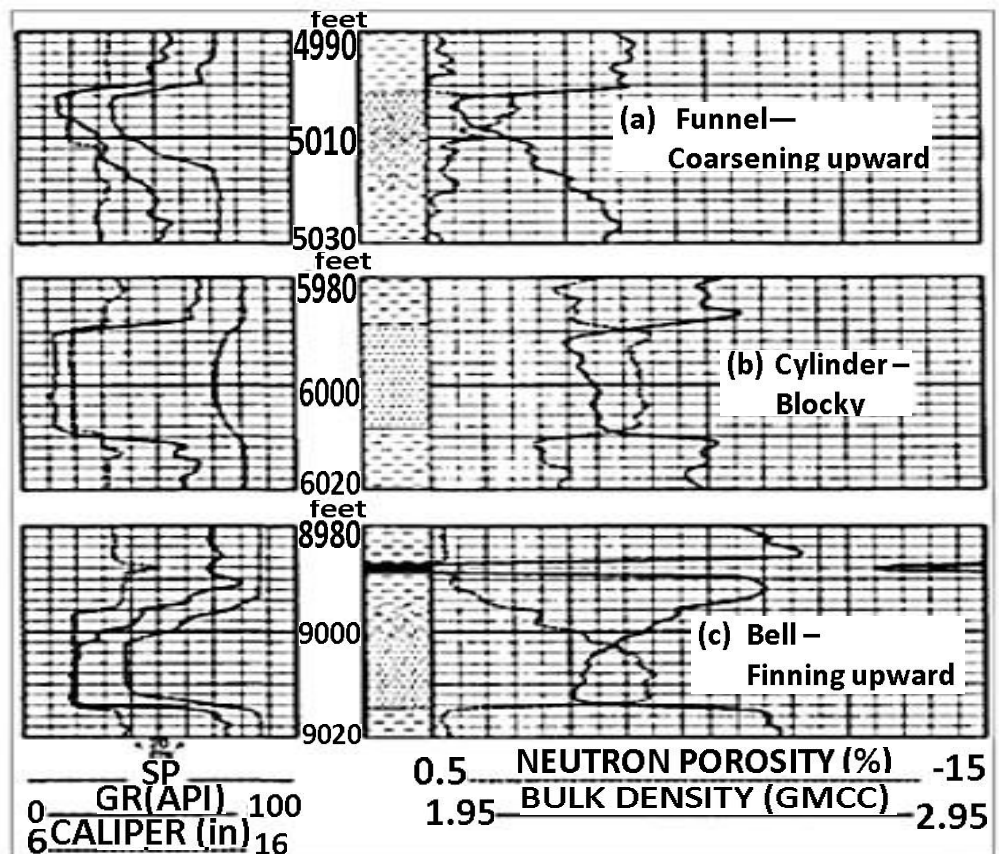


Figure 2.21 Characteristic log shapes for different types of sand bodies set in shale: (a) Funnel shape, coarsening upward. Note that this is the shallowest interval, so the shale is least compacted. (b) Cylinder shape, blocky. Note that the SP log is featureless because the borehole salinity is the same as formation salinity. (c) Bell shape, finning upward. Note that coal is present in addition to shale (Hancock, 1993).

The shape of the log is typically a reflection of the changing depositional energy from high (clean, coarser sand) to low (shaly, finer sand).

Table 2.3 Possible Interpretation of gamma log shapes based on depositional energy (Hancock, 1993)

Log shape	Depositional Energy	Possible Interpretation
Funnel	Upward increasing energy	Distributary mouth bars, deep sea fans, delta lobe fringes and other environments
Cylinder	Relatively constant energy levels	Eolian dunes, beaches and low distributary channels

Bell	Waning-current sequences	Alluvial point bars, deep sea fan channels and deltaic distributaries
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Figure 2.22 shows how a GR curve deflects as it passes through different lithologies.

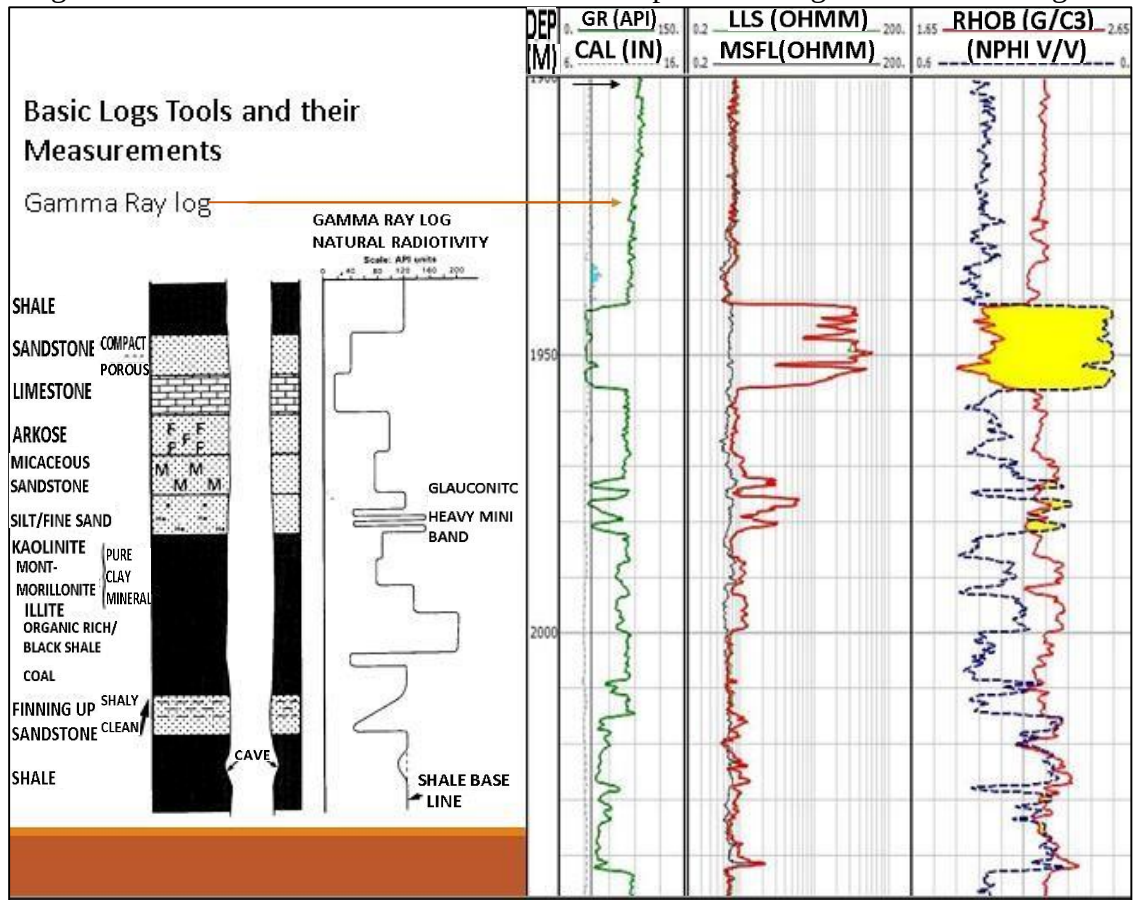


Figure 2.22 GR log behaviour through different lithologies (Swapnil, 2014)

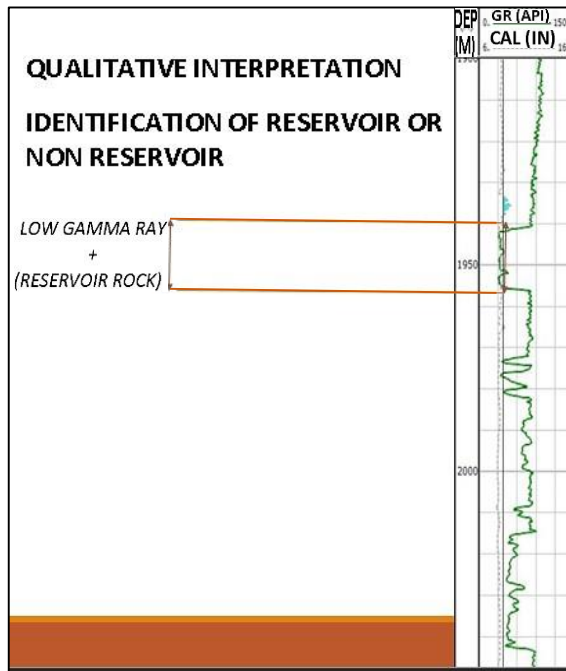


Figure 2.23 Reservoir identification using GR log (Swapnil,2014)

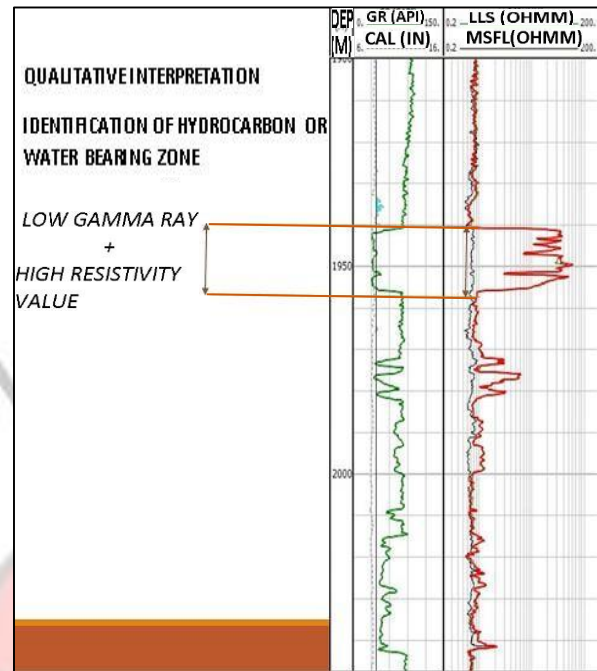


Figure 2.24 Hydrocarbon/water identification using GR log (Swapnil, 2014)

Figure 2.23 shows how GR curve deflections to the left indicate the possible presence of a reservoir. When coupled with a corresponding resistivity deflection to the right (Figure 2.24), it is a hydrocarbon/water bearing zone indicator.

Resistivity log track

The resistivity of a formation is a key parameter in hydrocarbon saturation determination. It depends on formation water resistivity, the geometry and structure of the pores, as well as the amount of water present. The resistivity of a substance (specific resistivity) is the electrical resistance measured between opposite faces of a unit cube of the substance at a specified temperature (SPE, 2015). According to the Society of Petroleum Engineers (SPE), it is generally based on the equation:

$$R = r \frac{L}{A} \dots \dots \dots 2.6$$

Where R = resistivity in $\text{ohm}\cdot\text{m}$, r

= resistance in ohm

A = area in m^2

L = length in m

Resistivity logs are used to determine the true resistivity of the formation. They distinguish between the type of fluid (fresh water, hydrocarbon or brine), and indicate the presence of movable hydrocarbons (by virtue of their electrical conductivity properties). A short penetration range reflects the presence of drilling mud whilst a longer one is due to the presence of formation water. Curve deflections towards the right most often indicate zones of higher resistivity, which is indicative of clean sands with either low porosity or the presence of hydrocarbons (SPE, 2015).

Low resistivity curves indicate the presence of wet sand (water zones) or shale, whilst a high resistivity reading usually means the sand is clean and hydrocarbons may be present. A high clean, porous sand with high resistivity is therefore good, although there are also exceptions to this rule. On a porosity resistivity overlay, moderate to high porosity accompanied by low resistivity, as well as the tracking of porosity with resistivity on an overlay (Crain, 2015), usually indicates the presence of water or shale.

High resistivity deflections to the right accompanied by high porosity (i.e. density deflections to the left) are usually indicative of oil, gas or fresh water. A crossover of resistivity and porosity curves usually indicates the presence of hydrocarbons. Superimposed deep, medium and shallow resistivity curves are always close to each other. Figures 2.25 and 2.26 show the typical behaviour of deep and shallow resistivity curves as they pass through different lithologies.

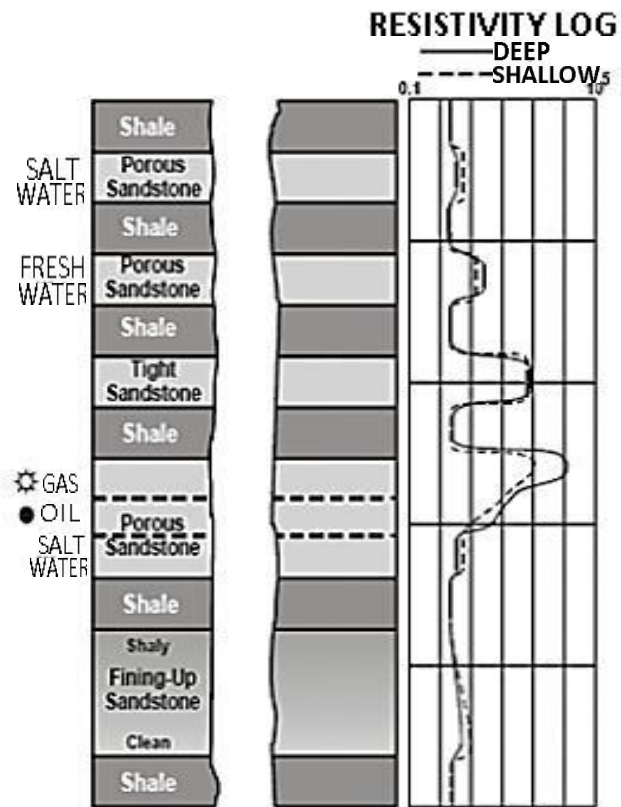


Figure 2.25 Typical resistivity log response (Hancock, 1993)

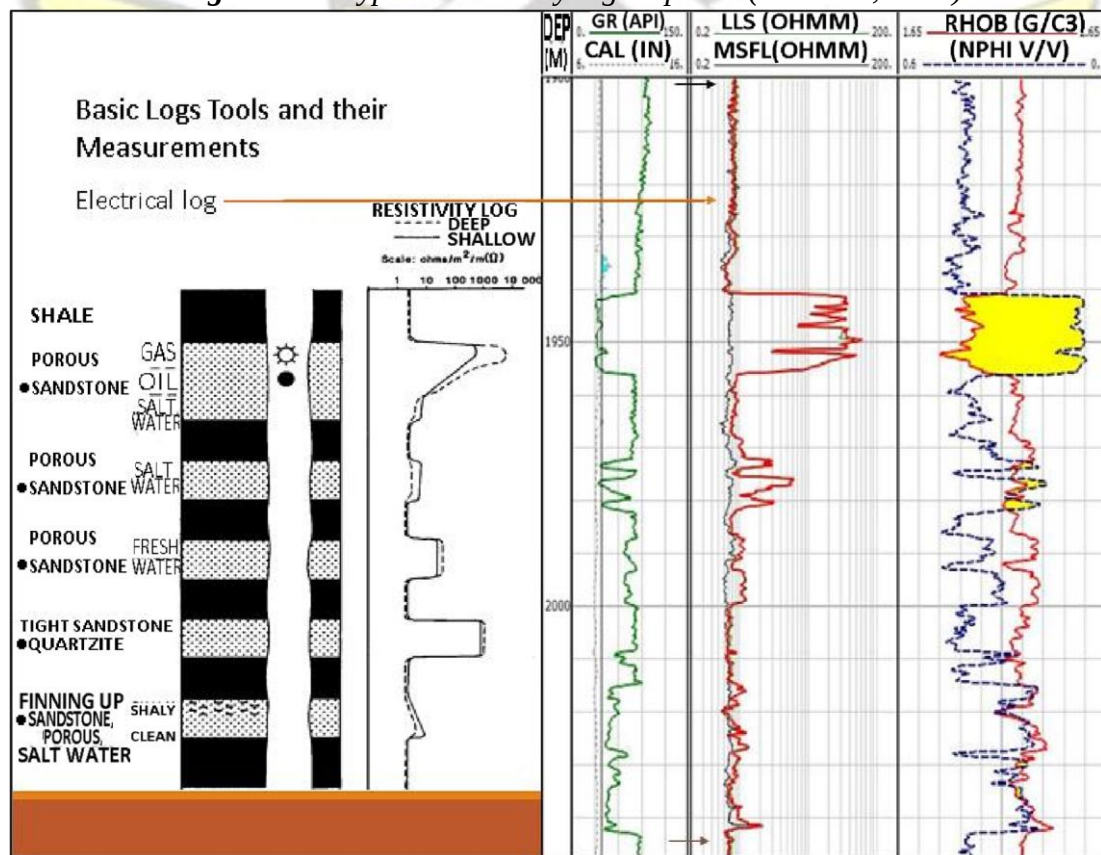


Figure 2.26 Resistivity log behaviour through different lithologies (Swapnil, 2014)

Sonic log track

Sonic logs measure how fast sound travels through rocks, and provide the formation's interval transit time (the time taken for the sound wave to travel the fixed distance between the piezoelectric transmitter and the receiver). The interval transit time varies with lithology and rock texture. In particular, it gives information on porosity by measuring the speed of the sound waves in the formation and indicates whether the pore space is occupied by a liquid or a gas. It also measures a number of sonic parameters like compressional and shear velocities (CPH, 2016).

From the sonic log track it is possible to identify zones with abnormally high pressures, identify gas bearing intervals, estimate rock permeability and facilitate cement evaluation. It also helps in the identification of lithology and fractures, facilitates VSP, AVO and synthetic seismograms interpretation, and improves the correlation and interpretation of seismic records. The basic relationship for the sonic log starts with the elastic constants of rocks (Crain, 2015):

$$V_p = KS4 \times (K_c/DENS)^{0.5}$$

.....2.7

$$V_s = KS4 \times (N/DENS)^{0.5} \dots\dots\dots 2.8$$

Where K_c = composite bulk modulus of the rock

N = composite shear modulus of the rock

$DENS$ = density of the rock

V_p = compressional velocity of the rock

V_s = shear velocity of the rock

$KS4$ = unit conversion term

Figure 2.27 shows the typical behaviour of a sonic log curve through different lithologies.

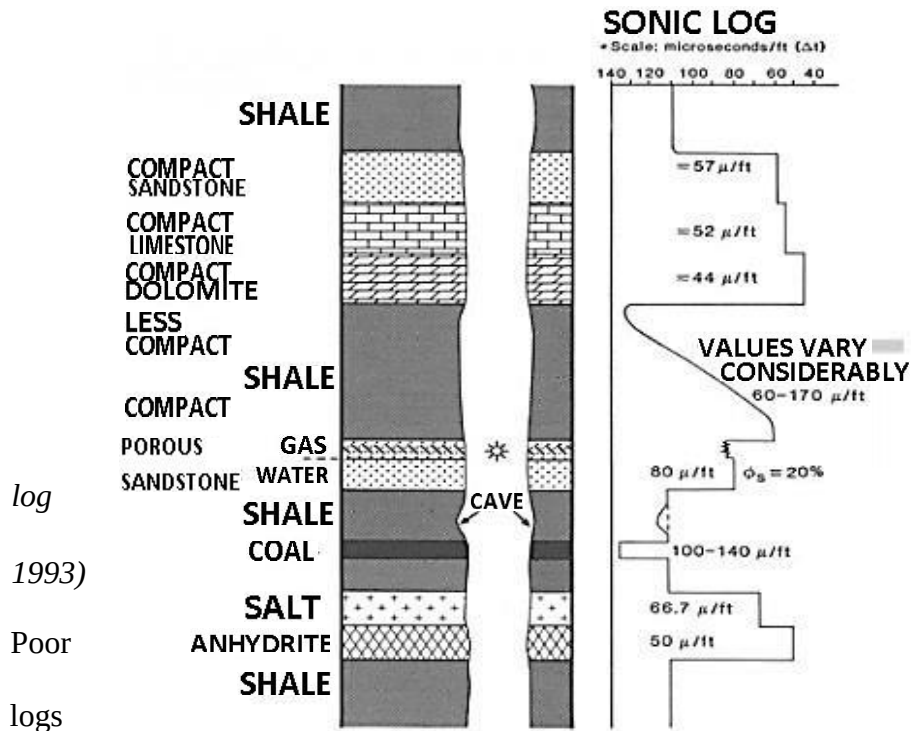


Figure 2.27
Typical sonic response (Hancock, 1993)

log
1993)
Poor
logs

quality sonic
with

corresponding spikes on shallow and deep resistivity suggest fractures, which can be confirmed with core and production rates.

Spontaneous Potential log track

The Spontaneous Potential (SP) log measures the natural or spontaneous potential difference between the borehole and the surface, in the absence of applied current. The electrochemical potential is the most useful component of this potential difference because it causes significant deflection in the SP response opposite permeable beds.

This deflection's magnitude depends mainly on the salinity contrast between the formation water and the drilling mud, as well as the clay content of the permeable bed. The SP log is therefore commonly used to detect permeable beds and estimate the clay content and formation water salinity.

Although the SP log is not a good indicator of lithologic boundaries, it can identify permeable zones and boundaries. It does so by measuring the electrical current that arises as a result of the salinity differences between the fluid in the formation and a salt water-based drilling mud. It can therefore distinguish shale from sandstones and

carbonates (as highly permeable porous sandstones generate more electricity than shale). Positive curve values (e.g. 0 to 20 mV) indicate shale and negative values (falling within the -20 to -80 mV range) indicate sandstones and carbonates (Wireline Logs, 2014).

The shapes of SP log tracks resemble those of the previously described gamma ray tracks and can be classified as either funnel, cylinder or bell-shaped. This is due to the qualitative shaliness indication given off by the SP log, making it possible for SP curves to be interpreted in a similar way to gamma ray curves (Hancock, 1993), except in the case of the complications listed below:

-Salinity contrast

Contrasting salinity has a critical effect on SP logs. Three scenarios are possible:

1. Fresh borehole fluid in a saline formation would give a “normal” SP curve.
2. Borehole with salinity identical to the formation would display a featureless SP curve with very low amplitude. It might even be a straight line with no obvious relationship to beds (cylinder or blocky shape)
3. Saline borehole in a fresher formation would give a reversed SP where the sands show positive deflections from the shale baseline.

In addition to salinity contrasts, other conditions can create problems in interpreting SP logs. Examples include:

- **Manual shifts**- On occasion, the logging engineer adjusts the SP log scale to keep it within the track.
- **Baseline shifts** - Although the value of the SP shale baseline is not significant, it will shift if formation fluid salinity changes from one bed to another, making the log hard to interpret.

- **Interference-** Remanent magnetism within the winching system often ruins SP logs. A sine-form SP whose cycle length is the circumference of the cable drum should be looked out for.
- **Mud type-** Water-based mud (with suitable salinity) is essential. Oil-filled or empty holes have nothing to carry the SP charges.
- **Hydrocarbons-** The SP is generated in water. High hydrocarbon saturation reduces the SP, making sands appear more shaly.

The relationship between the SP and the mud filtrate and formation water resistivities are determined using equation 2.9 (Mahmood, 2014):

$$SP = -K \log (R_{mfe}) / (R_{we}) \dots\dots\dots 2.9$$

Where SP = spontaneous potential

K = permeability

R_{mfe} = equivalent formation resistivity

R_{we} = equivalent water resistivity

Figures 2.28 and 2.29 show the typical lithology and typical permeability response of the SP log respectively.

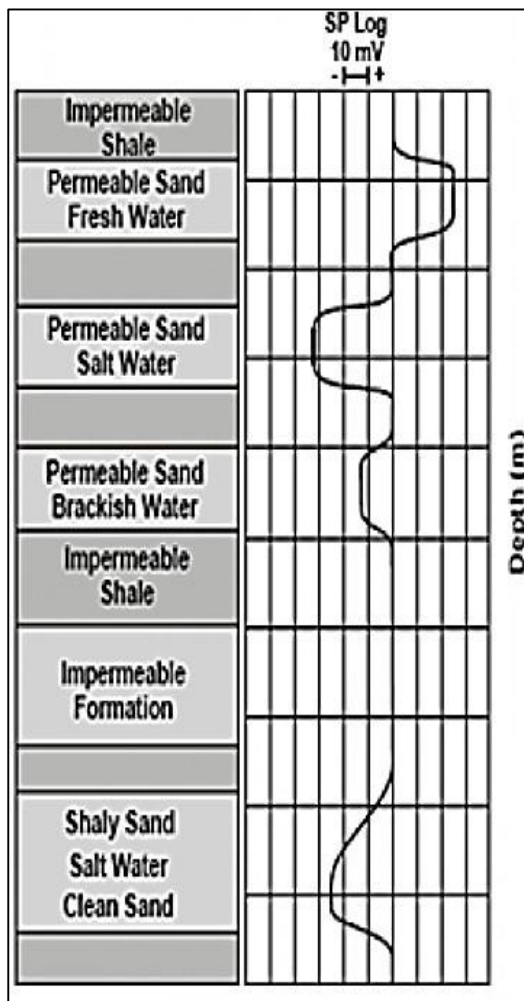


Figure 2.28 Typical lithology response of the SP log (Wireline Logs, 2014)

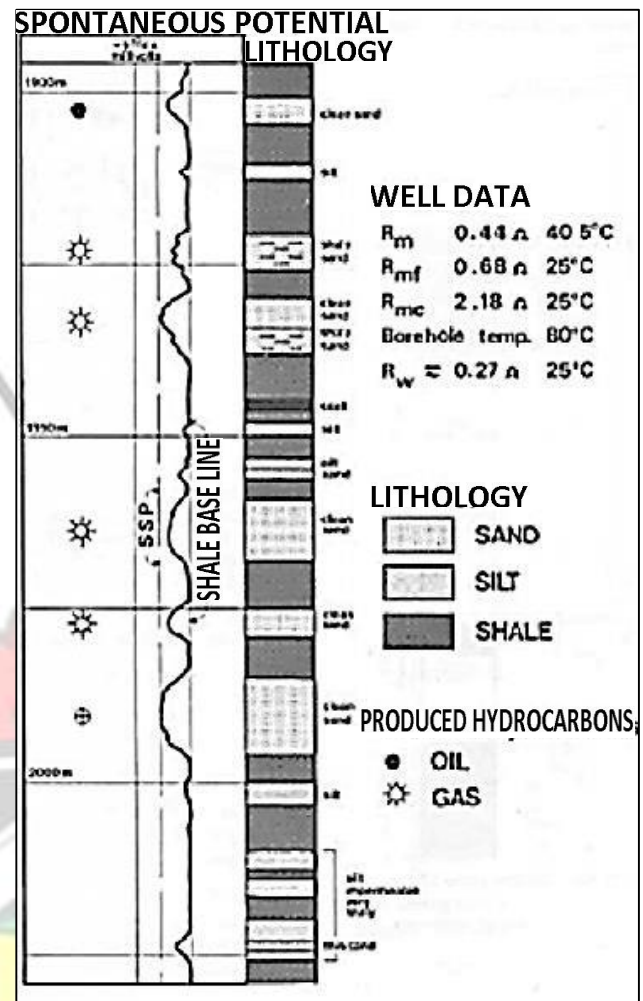


Figure 2.29 Permeability response of the SP log (Wireline Logs, 2014)

Neutron log track

Properly calibrated neutron logs (usually in API) provide important information about the content of the pore spaces within a rock matrix. The neutrons emitted from a neutron source are slowed down and eventually captured through interaction with hydrogen atoms. Once captured, a gamma ray of capture is created. Neutron Logging tools are designed to respond to slow Thermal Neutrons or Gamma Rays of Capture (WELLOG, 2007).

Since hydrocarbons and water (H₂O) contain hydrogen, neutron logs will provide knowledge of the hydrogen contained in the matrix pore spaces. In the presence of hydrogen, more neutrons are captured and as a result, fewer neutrons reach the

detector. Conversely in lower porosity, neutrons travel farther and successfully reach the detector, increasing the neutron count recorded at the detector. A lower neutron count therefore signifies increased fluid filled porosity (WELLOG, 2007). Neutron logs determine porosity by measuring the amount of hydrogen atoms (neutrons) in the pores. They do not represent lithology and as such are difficult to interpret alone. They are not usually affected by highly radioactive formations, and because they primarily represent fluid content, they cannot always be correlated (Crain, 2015).

The neutron log track generally resembles the resistivity log track. This resemblance is however slightly altered due to the presence of different neutron values as a result of the fluid variations in the medium. The lowest value found on the log track is usually shale- because in shale the fast neutrons are slowed down by hydrogen, reducing the incidence of capture and resulting in low secondary gamma ray radiation. Shale may therefore be used as a baseline for the neutron curve. A crossover on a neutron density log could also sometimes indicate the presence of gas. Rough hole problems such as sandstone recorded on a limestone scale, or limestone recorded on a dolomite scale may however also show a crossover which is not caused by gas (Crain, 2015).

A crossover between neutron porosity and density curves gives a strong indication of the presence of a fluid. When coupled with a high resistivity log reading, this fluid can be confirmed to be oil. Very large crossover widths indicate gas. Figure 2.30 describes typical responses of neutron logs to different lithologies.

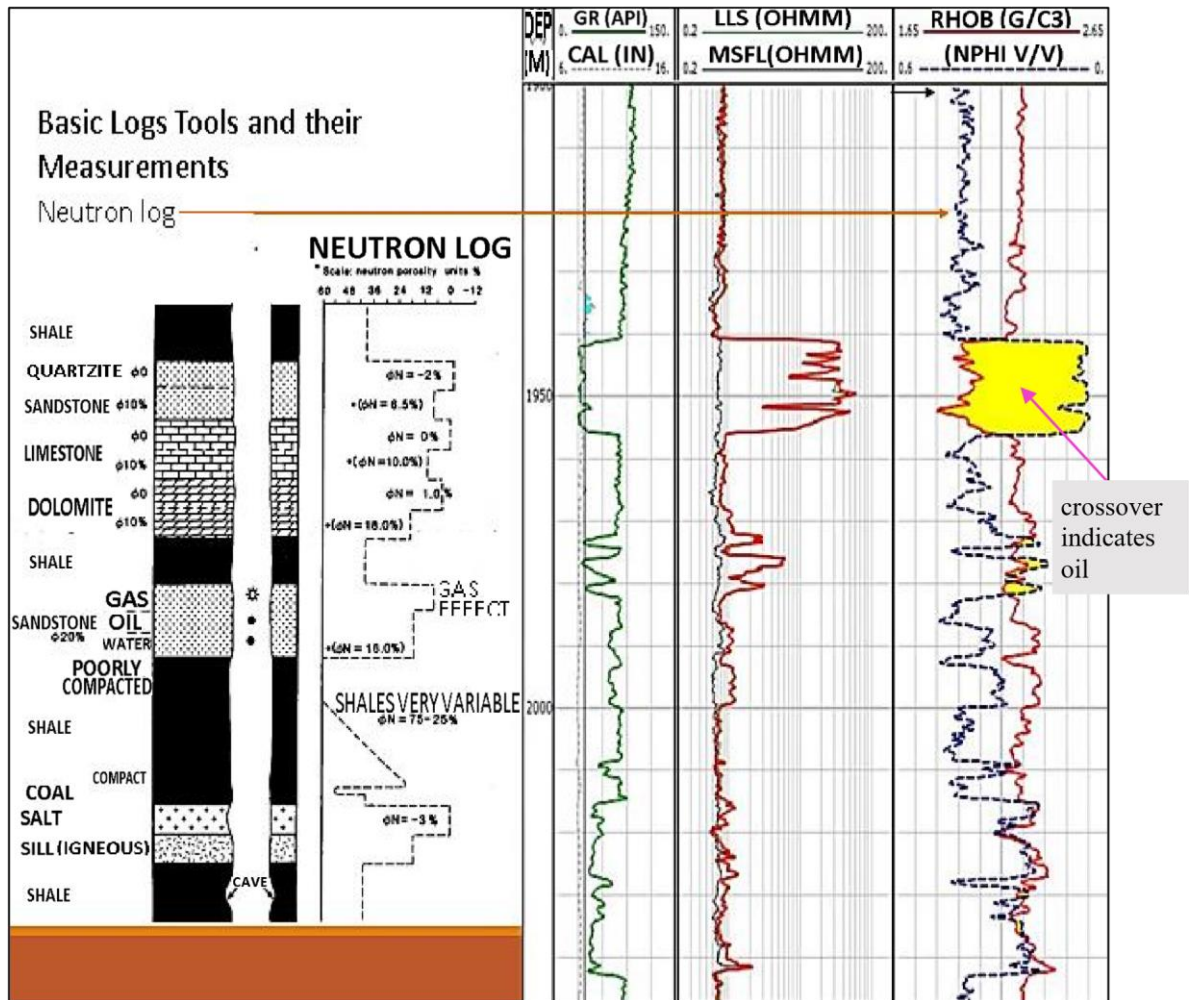


Figure 2.30 Neutron log behaviour through different lithologies (Swapnil, 2014)

By examining the SP, GR and neutron density separation, clean sand and shale lines can be drawn and linear interpolation between both lines can be done to have a visual estimate of the shale volume:

- Low values of GR with highly negative values of SP, or Neutron density curves which fall close to each other usually indicates low shale volume.
- High GR values without SP deflection, or large neutron density curve separation normally indicates a high shale volume. Very shaly beds are not zones of interest and as such everything else (including very shaly sands with $V_{sh} < 0.5$) (Crain, 2015), and even water zones can be considered as zones of interest.

Density log track

Density logs measure formation bulk density by bombarding the formation with a radioactive source and recording the resulting gamma ray count after the photoelectric absorption and Compton Scattering effects have taken place. It is used to determine the porosity and elastic properties of a formation and has numerous applications such as gas detection, mineral detection, thin bed delineation and shale gas evaluations. It is even more useful in hydrocarbon zone identification, when paired with other types of logs such as neutron or porosity logs (Crain, 2015).

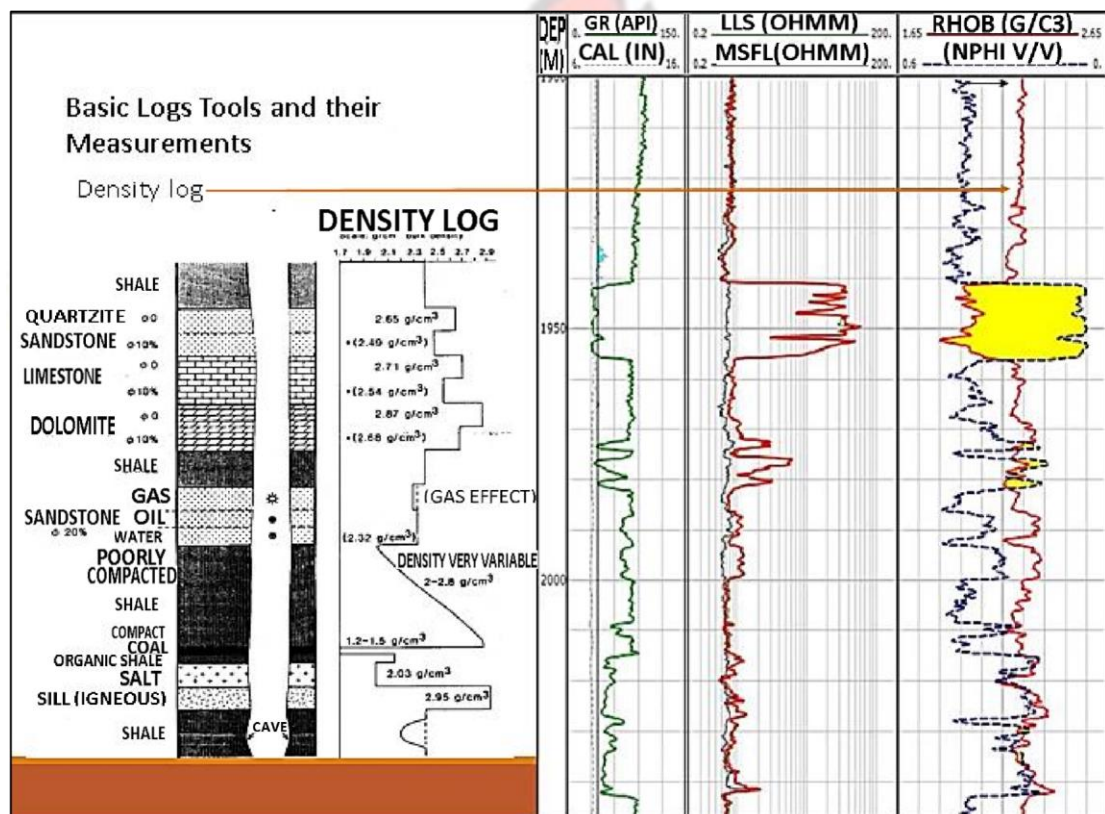


Figure 2.31 Density log behaviour through different lithologies (Swapnil, 2014)

Figure 2.31 shows the typical response of a density log curve in different lithologies.

According to (Wireline Logs, 2014), the normal scaling on a density log is 20 divisions of length 2.00 to 3.00 gmcc from left to right across two film tracks. Each division thus represents 0.05 gmcc. This makes it easy to find the bulk density (ρ_b) in gmcc.

For sandstones, the bulk density range is usually from 1.00 gmcc (water) in 100% porosity to 2.65 gmcc at zero porosity. A spread of 1.65 gmcc thus represents a spread of 100 P.U.s (porosity units), and each of the twenty log-scaling divisions represents 0.05 gmcc (Crain, 2015). The number of P.U.s in a scale division can be determined as follows:

$$\begin{aligned}1.65 \text{ gmcc} &= 100 \text{ P.U.s} \\0.05 \text{ gmcc} &= 0.05 \times (100 / 1.65) \text{ P.U.s} \\0.05 \text{ gmcc} &= 3.03 \text{ P.U.s}\end{aligned}$$

Denser formations have a much higher tendency to absorb more gamma rays while low-density formations absorb less. Low density is thus represented by high count rates at the detector.

Porosity

Porosity logs measure the percentage or fraction of pore volume in a volume of rock. There are two types of technologies applied in porosity logging. These are acoustic and nuclear technology. Acoustic logs measure the characteristics of sound waves which are propagated through the well-bore environment by the logging tool. Nuclear logs on the other hand utilize nuclear reactions that take place in the downhole logging instrument or in the formation (Shahnawaz, 2012). Neutron logs, density logs and GR logs are all classified under nuclear logs and are used in log correlation.

The principle behind using nuclear technology is that a neutron source placed near the formation whose porosity is being measured will result in neutrons being scattered by the hydrogen atoms, largely those present in the formation fluid (Ellis and Singer, 2007). Since the difference in the neutrons that are scattered by hydrocarbons or water is little, the porosity reading measured gives a value that is very close to that of the true physical porosity. In electrical porosity, the measured porosity is as a result of the electrical resistivity measurements in the conductive formation fluid. The difference

between both results is therefore an indication of the hydrocarbon presence in the formation fluid.

Often a combination of porosity devices is available that can be run into the wellbore together. Usually these combination tools can define porosity better than any single porosity device by itself. Of all the combinations, the neutron/density combination is the most commonly available (PCO, 2009).

Once the log scale and number of units per log division have been identified, coupled with the type of curve recorded (e.g. neutron porosity, bulk density, density porosity, acoustic travel time), and the lithology if available, the true porosity can be determined in the intervals where the particular porosity device under consideration can reasonably be expected to work. The resulting measurements will not only reflect porosity, but also the type of rock, the clay content, and the fluid type. The average of density and neutron porosity in a clean zone (regardless of mineralogy) is a good first estimate for Effective Porosity (PHI_e), and so is the density porosity in a shaly sand, provided the logs are on Sandstone Units (Crain, 2015).

For zones of interest, bed boundaries (horizontal lines) should be drawn. The GR log should be compared to the porosity log in order to mark clean and porous zones which are potential hydrocarbon containing zones. The porosity logs (sonic, density, and neutron) should then be reviewed. All porosity logs deflections to the left are indicators of increased porosity and those to the right of decreased porosity. Where neutron density data is available, the porosity in clean sands can be determined by averaging the two log values. In shaly sands however, the density porosity log should be read to give an estimation of the porosity value (Crain, 2015).

According to Porosity Log lecture notes from the Faculty of Mathematics and Natural Sciences at the University of Oslo (UIO, 2015), a sonic-derived porosity log (SPHI) may be generated from the Sonic log using equations 2.10 - 2.12:

-Wyllie Time-average

$$\phi_s = \left(\frac{\Delta t_{log} - \Delta t_{matrix}}{\Delta t_{log} - \Delta t_{matrix}^{matrix}} \right) \dots \dots \dots 2.10$$

Where ϕ_s = sonic porosity

t_{log} = log transient time

t_{matrix} = matrix transient time

t_f = formation transient time

- Raymer-Hunt-Gardner

$$\phi_s = \left(\frac{5}{8} \times \frac{\Delta t_{log} - \Delta t_{matrix}}{\Delta t_{log}} \right) \dots \dots \dots 2.11$$

Where ϕ_s = sonic porosity

t_{log} = log transient time

t_{matrix} = matrix transient time

- For unconsolidated formation

$$\phi_s = \left(\frac{\log \frac{matrix}{\Delta t_{tf} - \Delta t_{matrix}}}{100 \times C} \right) \times 1/C_p, \text{ with } C_p = \left(\Delta \dots \dots \dots 2.12$$

Where CP = compaction factor

C = constant, normally 1.0

t_{sh} = shale transient time

2.2.6.2 Well Log Interpretation

There are basically two types of properties that are important to reservoir characterisation, these are petrophysical properties (shale volume, permeability, water saturation etc.) and rock physics properties (elasticity, wave velocity etc.). The former are more related to geology whilst the latter are more inclined towards geophysics. All the properties are however inter-related and several logs may be used to interpret a particular property (Hancock, 1993).

In predicting reservoir properties, stratigraphic and lithological interpretation is very important and should be done first. This is because if the lithological interpretation is wrong, all the other steps such as water saturation calculation, porosity etc. will also be affected. Well log interpretation should thus always be done in a particular order following several steps. Ignoring this and doing random analysis would most probably result in a total error (AAPGWiki, 2014). Figure 2.34 shows the order that must be followed when using log data for reservoir characterisation.

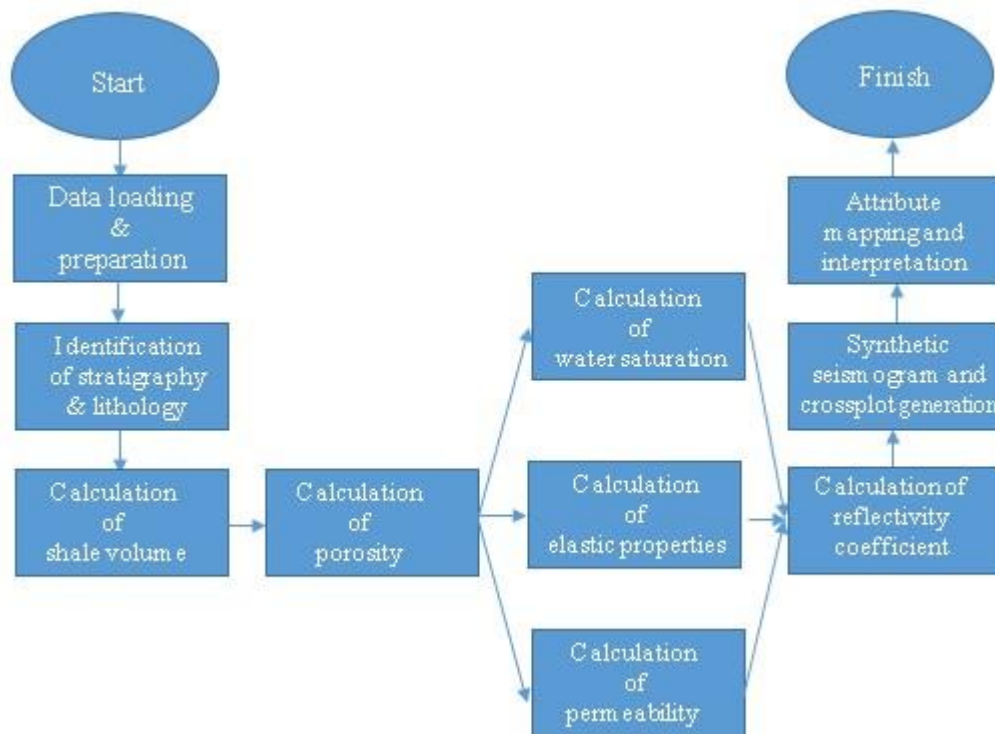


Figure 2.32 Methodology flow chart for data processing and interpretation (Asquith et. al, 2004)

Lithology Interpretation from Logs

Lithology may be determined from logs because the lithology of each main reservoir has characteristic responses. The logs that are best suited for lithological identification are those that are most influenced by rock properties and least influenced by fluid properties (Hancock, 1993). The gamma ray log is an example, as the three common radioactive elements- potassium, uranium and thorium- are virtually undetected in reservoir fluids but easily noticed in rock systems like clay minerals etc. Most often, the pattern recognition of the Gamma ray, density (RHOB), resistivity (LLD and LLS), spontaneous potential and neutron log responses are used to derive lithology (Schlumberger, 1985)

With the density log it is possible to determine whether the formation is tight or not, and subsequently differentiate between shale-shaly-non shale formations. The shale formations usually have low density whereas the non-shale formations usually have higher density values. In between them lies the shaly formation. If the formation has a

very high density log reading it may be classified as a “tight” formation and when its corresponding gamma ray log reading is around 30-50, it may be identified as a “tight sandstone” formation. If, however, the gamma ray log reading is very low (usually below 15 API), whilst the resistivity and density log reading are very high, it could be an anhydrite- which is a good cap rock in petroleum system (AAPGWiki, 2014).

Resistivity logs may also help with the differentiation between different lithologies.

Sandstone or carbonates have high resistivity and when a formation’s resistivity reading is higher than the average resistivity of the zone, that area can be classified as sandstone (if the gamma ray value is low to medium) or carbonate (if the gamma ray value is very low).

Table 2.4 shows the typical responses of several logs to lithology. The reference value is relatively different for every well, so there will be variations from well to well.

Table 1.4 Petrophysical properties reference of some sedimentary rocks (AAPGWiki, 2014)

Lithology	Gamma Ray (API)	Spontaneous Potential (mV)	Resistivity (Ωm) [If shale resistivity is 8]	Density (gr/cm^3)
Sandstone	30 – 50	Varies, very negative	10+	2.4 – 2.8
Shalysandstone	50 – 75	Varies, negative	8 < Resistivity < 10	Around 2.4
Sandy-shale	75 – 90	Varies, negative	Around 8	Around 2.3
Shale	Higher than 90	Higher than 0	8	Around 2.3

Anhydrite	Below 15	-	Very high, up to 100+	Up to 2.9
Coal	Varies	-	Varies	Varies, could be 1.7 – 2.2
Crystalline	Below 30	-	Very high, up to 150+	Up to 2.9
Limestone	20 – 30	-	Very high, up to 100+	2.3 – 2.7

Reservoir Interpretation from Logs

Reservoir evaluation from well logs can be achieved following the steps outlined in Figure 2.33.



Figure 2.33 Reservoir determination flowchart (Swapnil, 2014)

Hydrocarbons (oil/gas) and water bearing zones can be delineated from well logs when the curve deflections resemble those in Figure 2.34.

QUALITATIVE INTERPRETATION

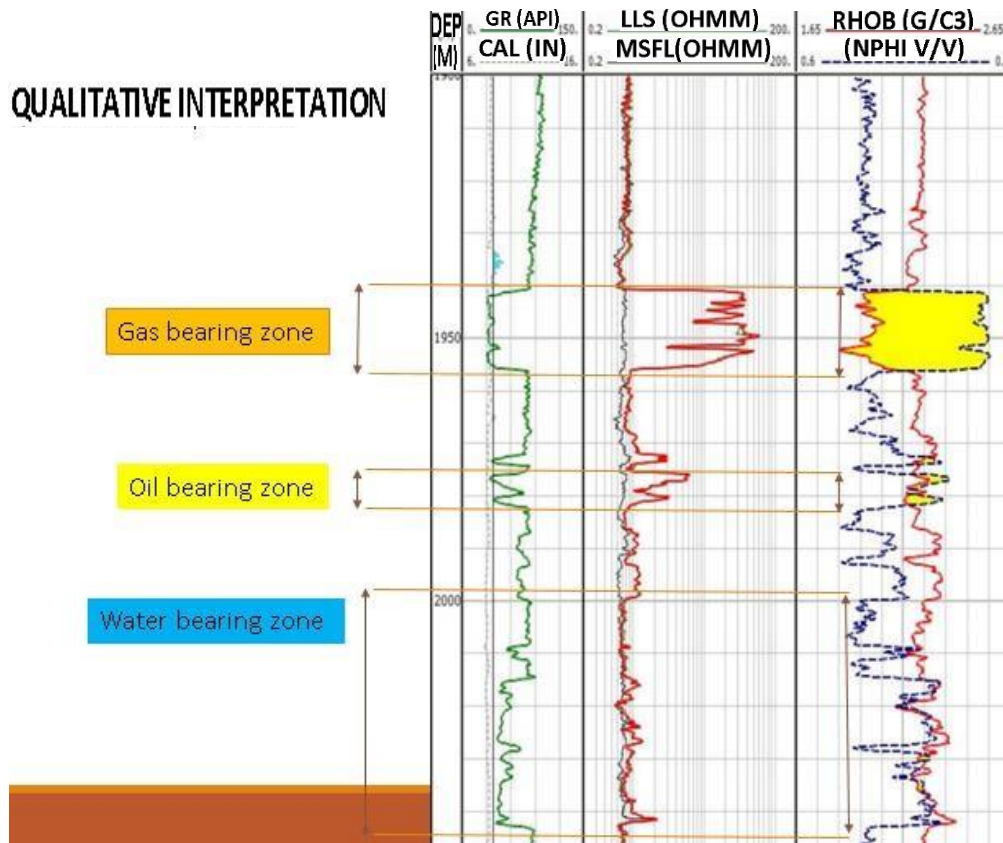


Figure 2.34 Oil, gas and water delineation from logs (Swapnil, 2014)

Furthermore, the delineation can be done with the aid of quantitative calculations.

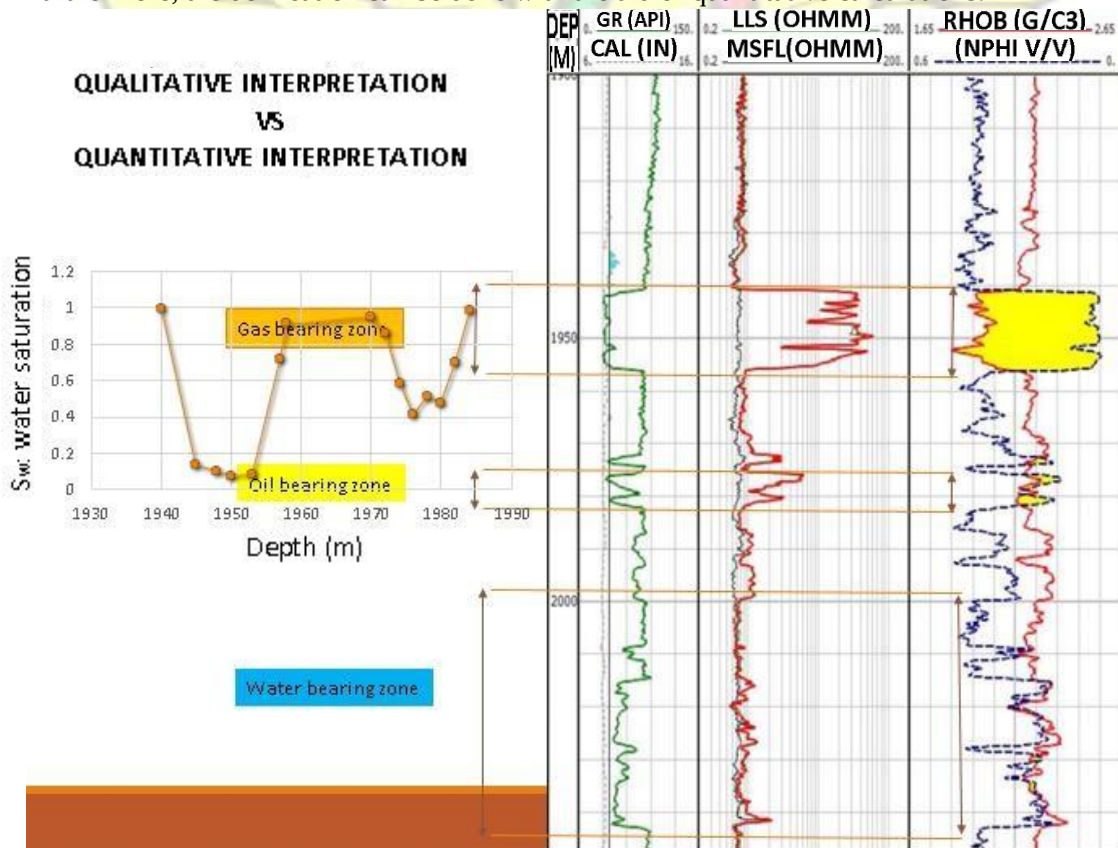


Figure 2.35 Identification of reservoir zones using quantitative analysis (Swapnil,

2014)

Figure 2.35 shows the quantitative (on the left) and qualitative (on the right) delineation of hydrocarbon and water bearing zones.

After stratigraphic and lithologic identification, interpretation can proceed to formation evaluation. According to (Shahnawaz, 2012), the basic logs which are required for adequate formation evaluation are:

1. Permeable zone logs (SP, GR, Caliper)
2. Resistivity logs (MFSL, Shallow and Deep resistivity logs)
3. Porosity logs (Density, Neutron and Sonic)

In general, the first track on the log represents the permeable zone logs, the second track contains the resistivity logs whilst the third track displays the porosity logs. By using such a set of logs, the interpreter's main goal will be answering two questions: where are the potential producing hydrocarbon zones and how much hydrocarbons (oil or gas) do they contain.

In doing this, the first step in log interpretation would be to locate the permeable zones. This is achieved by scanning the log in the first track. There is a base line located on the right. This line is referred to as the shale base line and it indicates the presence of shale (i.e. the impermeable zone). When the line swings to the left it indicates clean zones like limestone, sand etc. These are the zones that must immediately be focused on during interpretation.

The second step is to scan the resistivity logs located in the second track to identify all the zones that give off large resistivity curve deflections to the right. These high resistivity values are indicative of either the presence of hydrocarbons in the pores, or a zone of low porosity.

The third step would be to scan the porosity log in the third track to determine which of the zones that showed high resistivity values on the second track also have good porosity values. This enables the interpreter to distinguishing between a hydrocarbon bearing zone and a zone

whose high resistivity readings are as a result of low porosity. The tight formations may then be discarded and the interesting zones should subsequently be selected for formation evaluation (Crain, 2015).

2.2.7 Software and Algorithms Used

Kingdom SMT with 2D/3D/Earthpack modules was used to analyse the data. For the maps generation, several algorithms were employed:

2.2.7.1 Flex Gridding

For the formation of grids from the picked horizons, this algorithm was chosen. Flex gridding employs a system of differential equations to yield grid node values that meet two main criteria. The interpolated surface must pass through or at least very close to the data in the XYZ space and the surface must as much as possible fit the mathematical criterion selected by the user (without violating the first criterion) (GNPC,2015).

According to GNPC, (2015), this criterion can be one of following:

- i. Minimum Tension or rubber sheet- Here the LaPlacian operator is used to generate the solution for each grid node. Like a rubber sheet with a grommet at each grid node, the surface will be tightly stretched over the data over a set of posts through each grommet. When a node has data, the grommet will be nailed to the post at the level of the datum, whilst the other grommets will slide up or down their posts under the tension of the stretched rubber. The sheet will then relax to a position where its tension is minimized.
- ii. Minimum Curvature or as smooth as possible- Here the Biharmonic operator is used to give the solution for each grid node. The root mean square (*RMS*) surface curvature will be as smooth as possible. Instead of a

rubber sheet as described in the previous option, it will behave like a thin sheet of spring steel that will relax to the smoothest surface when data containing grommets are nailed to their posts, and the surface will relax to the position where the overall curvature is minimized.

- iii. A blend of the previous two- here the operator will use a weighted blend of the Biharmonic and Laplacian operators.

Because a simultaneous solution of all the equations is computationally intractable, an iterative solution is used. Each of the equations applies to one grid node and has terms that include just a dozen of its neighbours. They are thus all coupled together. The coupling to distant nodes is however weak and indirect and for this reason each equation is solved to yield a grid value, assuming the neighbouring nodes are constant. As the nodes change the process is repeated and with an infinite number of iterations the grid will converge the desired solution. The best results are however obtained with far fewer iterations. The flexing of the tiny coarse grid massages in the overall trends, and the flexing of the finer grids works in the local details so the finer grids do not need a large number of passes of the flexing filter (GNPC,2015).

2.2.7.2 Kriging

For the formation of contours on the grids, this algorithm was chosen.

Kriging is a type of point interpolation which requires the use of a point map as input to produce a raster map with estimations and an error map as an optional output. The estimations are calculated as weighted averages of known input point values, similar to the Moving Average operation (GNPC, 2015). The estimate to be calculated (i.e. an output pixel value $\hat{Z}$) is a linear combination of weight factors (w_i) and known input point values (Z_i):

$$\hat{Z} = S (w_i * Z_i) \dots \dots \dots 2.13$$

In case the value of an output pixel would only depend on 3 input points, this would read:

$$\hat{Z} = (w_1 * Z_1) + (w_2 * Z_2) + (w_3 * Z_3) \dots\dots\dots 2.14$$

Thus, to calculate one output pixel value $\hat{Z}$, first, three weight factors w_1, w_2, w_3 have to be found (one for each input point value Z_1, Z_2, Z_3). Then, these weight factors can be multiplied with the corresponding input point values, and summed.

In Moving Average, the weight factors are simply determined by the distances of the input points towards an output pixel. In Kriging, however, the weight factors are calculated by finding the semi-variogram values for all distances between input points and by finding semi-variogram values for all distances between an output pixel and all input points. A set of simultaneous equations then has to be solved. When the spherical distance option is used, distances are calculated over the sphere using the projection of the coordinate system that is used by the geo-reference of the output raster map.

All semi-variogram values are calculated by using a user-specified semi-variogram model (based on the output of the spatial correlation operation). The weight factors are calculated in such a way that the estimation error in each output pixel is minimized. The error map option contains the standard errors of the estimates (GNPC,2015).

2.2.7.3 Bilinear Resampler

For the calculation of the Gross Rock Volume (GRV) from the Volumetric toolbar, the Bilinear Resampler algorithm was used.

It is a resampling method that uses the average weighted distance of the four nearest pixel values to estimate a new pixel value. It is basically an extension of linear

interpolation for interpolating functions of two variables (e.g. x and y) on a rectilinear 2D grid.

The key idea involves first performing a linear interpolation in one direction, followed by one in the other. Though each step is linear in the sampled values and in the position, the interpolation as a whole is not linear but rather quadratic in the sample location. The four cell centers from the input raster closest to the cell center for the output raster will be weighted based on distance and then averaged (GNPC, 2015).

Supposing we would like to find the value of the unknown function f at the point (x, y) , and assuming that the value of f at the four points $Q_{11} = (x_1, y_1)$, $Q_{12} = (x_1, y_2)$, $Q_{21} = (x_2, y_1)$, and $Q_{22} = (x_2, y_2)$ is known, the resampler:

a) first does a linear interpolation in the x -direction yielding:

$$f(x, y_1) \approx \frac{x_2 - x}{x_2 - x_1} f(Q_{11}) + \frac{x - x_1}{x_2 - x_1} f(Q_{21})$$

f2.15

$$f(x, y_2) \approx \frac{x_2 - x}{x_2 - x_1} f(Q_{12}) + \frac{x - x_1}{x_2 - x_1} f(Q_{22})$$

f2.16

b) then proceeds by interpolating in the y -direction to obtain the desired estimate:

$$f(x, y) \approx \frac{y_2 - y}{y_2 - y_1} f(x, y_1) + \frac{y - y_1}{y_2 - y_1} f(x, y_2)$$

f2.17

$$\approx \frac{y_2 - y}{y_2 - y_1} \left(\frac{x_2 - x}{x_2 - x_1} f(Q_{11}) + \frac{x - x_1}{x_2 - x_1} f(Q_{21}) \right) + \frac{y - y_1}{y_2 - y_1} \left(\frac{x_2 - x}{x_2 - x_1} f(Q_{12}) + \frac{x - x_1}{x_2 - x_1} f(Q_{22}) \right)$$

$$y_2 - y_1 \quad x_2 - x_1 \quad x_2 - x_1$$

$$f(x, y) = \left(\frac{x_2 - x_1}{y_2 - y_1} \right) \mathbf{1}(y_2 - y_1) [x_2 - x_1] [f(Q_{2111})] f(Q_{2212}) [y_2 - y_1]$$

The same result will be obtained irrespective of whether the interpolation is first done along the y-direction, and then along the x-direction (Wikipedia, 2016).

2.2.7.4 Vatmax

Where both horizons have data, *vatmax* is instructed to compute the maximum of the absolute value of the amplitudes within a window by retaining the most positive amplitudes in the depth range. This is used to map the strongest direct hydrocarbon indicators within a zone of interest (GNPC, 2015).

2.2.7.5 Vatmin

Where both horizons have data, *vatmin* is instructed to compute the value of the minimum amplitudes within a window by retaining the most negative amplitudes in the depth range (GNPC, 2015).

2.2.7.6 Vatrms

Where both horizons have data, *vatrms* is instructed to compute the root mean square divided by the number of samples within the specified window used. With this, the reflectivity can be directly measured and used to map direct hydrocarbon indicators in a zone of interest. *Vatrms* is however sensitive to noise- as it squares every value within the window (GNPC, 2015).

2.2.8 Data Sets Used

The data provided by GNPC and used in the execution of this research consisted of:

1. Offshore Subsea 3D Pre-Stack Depth Migrated (PSDM) Seismic Data

2. EEI Data Conditioned Towards Lithology
3. Formation Tops Location Specifications
4. Oil-Water Contact Specifications
5. Well Completion Logs
6. Composite Well Logs containing:
 - Gamma Ray logs
 - Density logs
 - Porosity logs
 - Resistivity logs (Shallow, Medium and Deep)
 - Sonic logs
 - Neutron Porosity logs
 - Spontaneous Potential logs
 - Total Gas
 - Hole Caliper logs
 - Density Caliper logs

The seismic data provided by GNPC was preconditioned to match well data through the application of synthetic seismograms obtained from VSP data. It therefore constituted of time depth data in which the wells had already been correctly tied to the seismic data and hence made the generation and use of synthetic seismograms in the data loading stage no longer necessary.

2.2.9 Site Location

The Tano Basin is located in south-western Ghana and occupies an area of at least 3000 km², with an onshore component estimated at about 1165 km². Located approximately 39 and 24km from the Ghana coast and east of the Ghana- Cote d'Ivoire border respectively, it has a water depth ranging from 91 to 125 m (Atta-Peters and Garrey, 2014). The survey area is located in the Western Tano Basin, somewhere within the Tano Block displayed in the activity map in Figure 2.36.

Activity Map

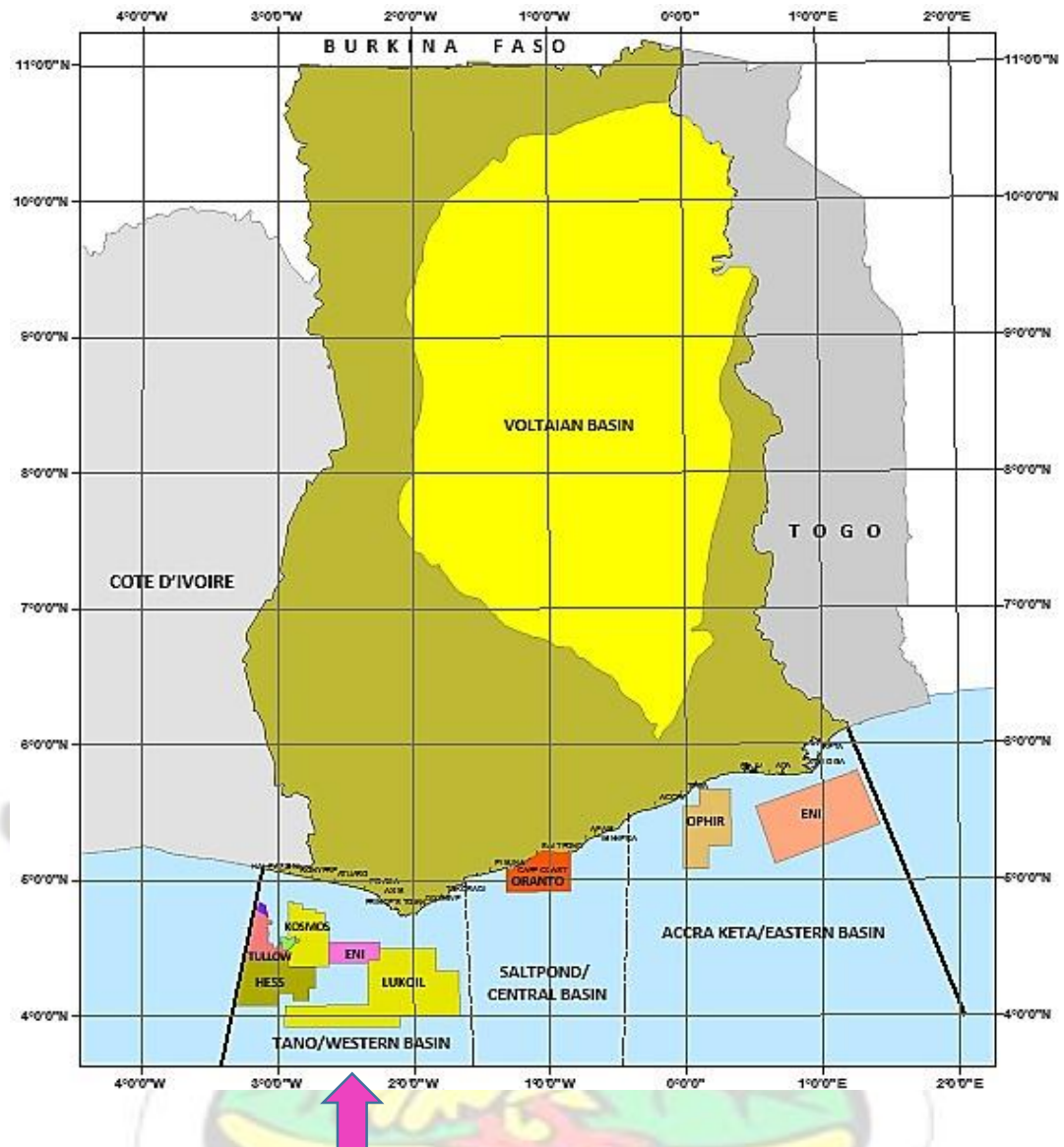


Figure 2.36 Ghana's four sedimentary basins showing the Western Tano Basin (GNPC, 2016)

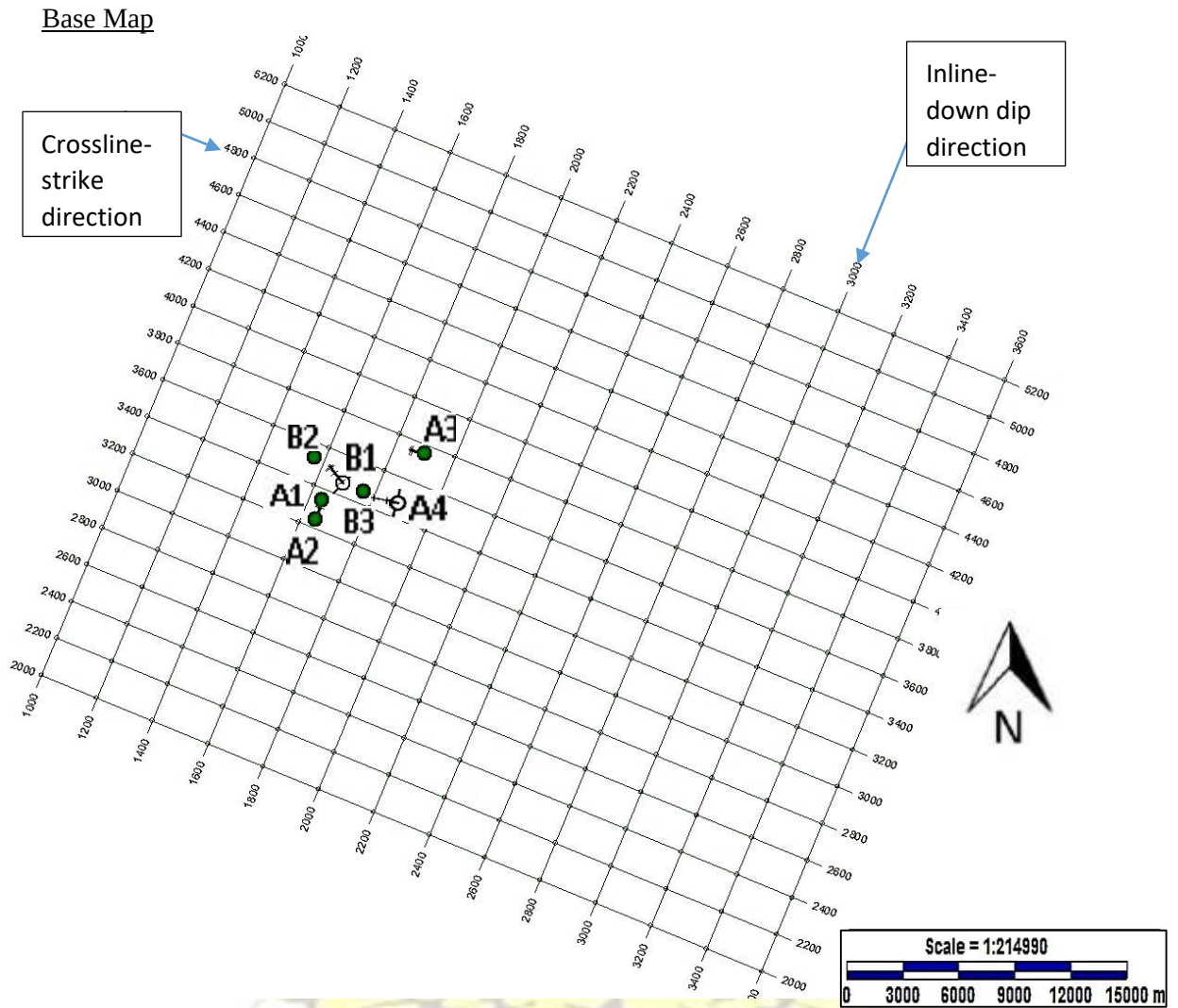


Figure 2.37 Base map of survey area

The exact location from which the base map (Figure 2.37) originated was withheld in order to preserve data anonymity. The base map is divided into 14 inlines (dip lines) and 17 crosslines (strike lines) with an interval spacing of 200 survey lines between consecutive inlines/crosslines. A polygon encompassing the reservoir zone of interest with a total coverage area of 696.88 km² was demarcated within the grid and used as the area of study. Seven wells named A1, A2, A3, A4, B1, B2 and B3, were situated within the polygon of interest in the area of study. With the exception of wells A4 and B1 which are appraisal wells, sufficient log data for petrophysical analysis was provided for all the wells located within the study area.

2.2.10 Stratigraphy and Geology of the Study Area

2.2.10.1 Stratigraphy of the Gulf of Guinea Province of West Africa

The Gulf of Guinea Province is situated in the north-western part of the Gulf of Guinea and includes the Ivory Coast, Benin, Keta, Central, Saltpond and Tano Basins, as well as the Dahomey Embayment. These basins were grouped together as one province because they share common structural and stratigraphic characteristics. They are all wrench-modified basins (Clifford, 1986) and contain rocks ranging in age from Ordovician to Holocene (Kjemperud et al., 1992). The Gulf of Guinea Province (Figure 2.38) is bounded on the east by the Niger Delta Province, and on the west by the West African Coastal Province (Klett et al., 1997).

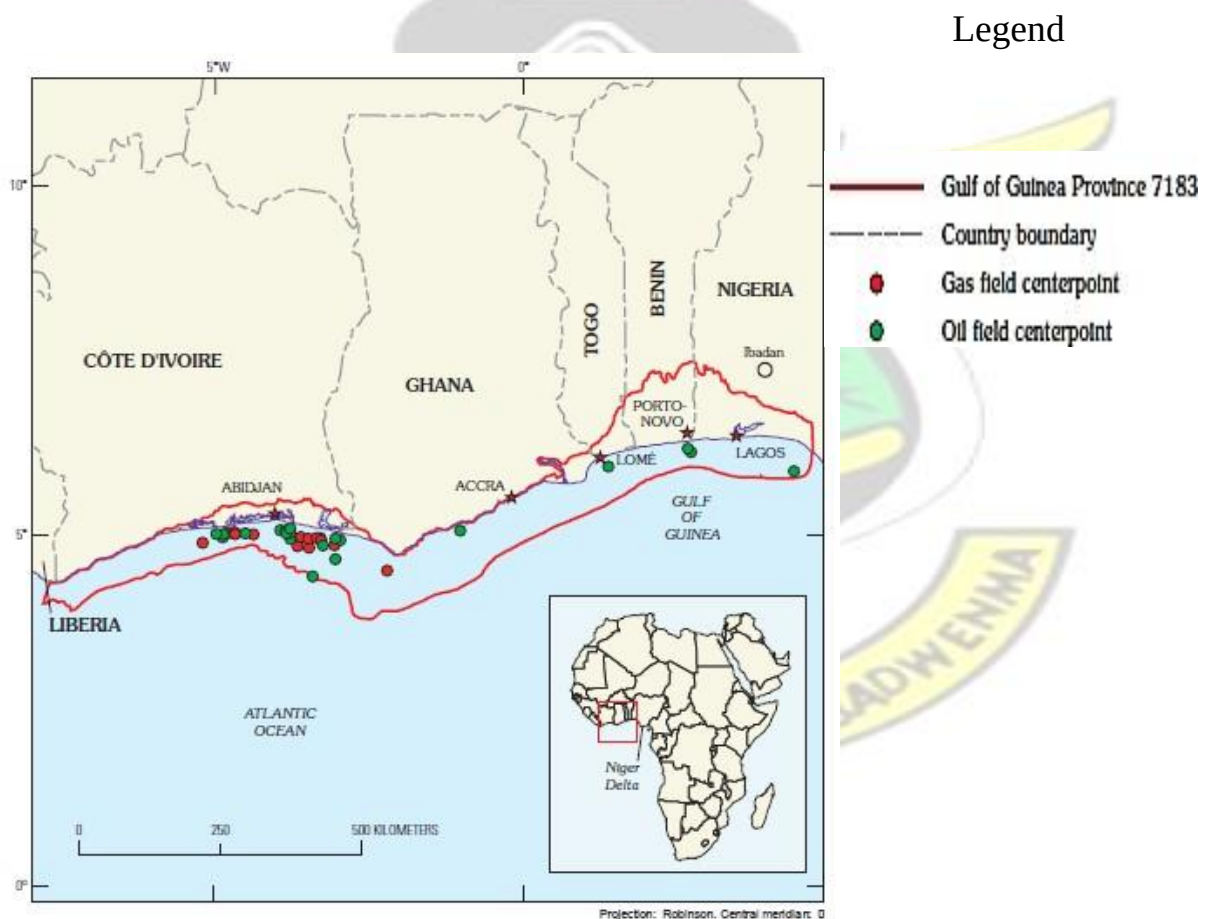


Figure 2.38 Gulf of Guinea Province (7183) in west-central Africa showing locations of oil and gas field centre points (Petroconsultants, 1996).

The Gulf of Guinea was formed at the culmination of the Late Jurassic to Early Cretaceous tectonism that was characterized by both block and transform faulting superimposed across an extensive Paleozoic basin during the breakup of the African, North American, and South American paleocontinents (Brownfield & Charpentier, 2006).

The province has thus undergone a complex history which has been divided into three stages of basin development; the pre-transform (late Proterozoic to Late Jurassic), syntransform (Late Jurassic to Early Cretaceous), and post-transform (Late Cretaceous to Holocene) stage. These three stages are also referred to as the pre-rift (or intracratonic), syn-rift (or rift), and post-rift (or drift) stages by (Dumestre, 1985), (Kjemperud et.al., 1992), (Tucker, 1992), and (Chierici, 1996). The structural basins within the province are generally aligned in the east-west direction with boundaries delimited by an east-west transform fault system and north-south structural arches.

This research was centered on an area within the Tano Basin which falls under the post-transform stage- in the Santonian age of the Upper Cretaceous system. The Tano Basin mainly has an extensional structural style and is located in the West African Transform Margin between the Romanche & St Paul transform faults (Sutherland, 2008). The portion of the basin that has proven to be of high hydrocarbon potential is located about 60 km offshore Ghana with water depth ranging from 1200 km to 1500 km (Tetteh, 2016). The general stratigraphy of the offshore and onshore parts of the Saltpond and Tano Basins showing the age, lithology, approximate stratigraphic horizon of field discoveries, geologic setting, and tectonic stage are described in the composite stratigraphic column in Figure 2.39.

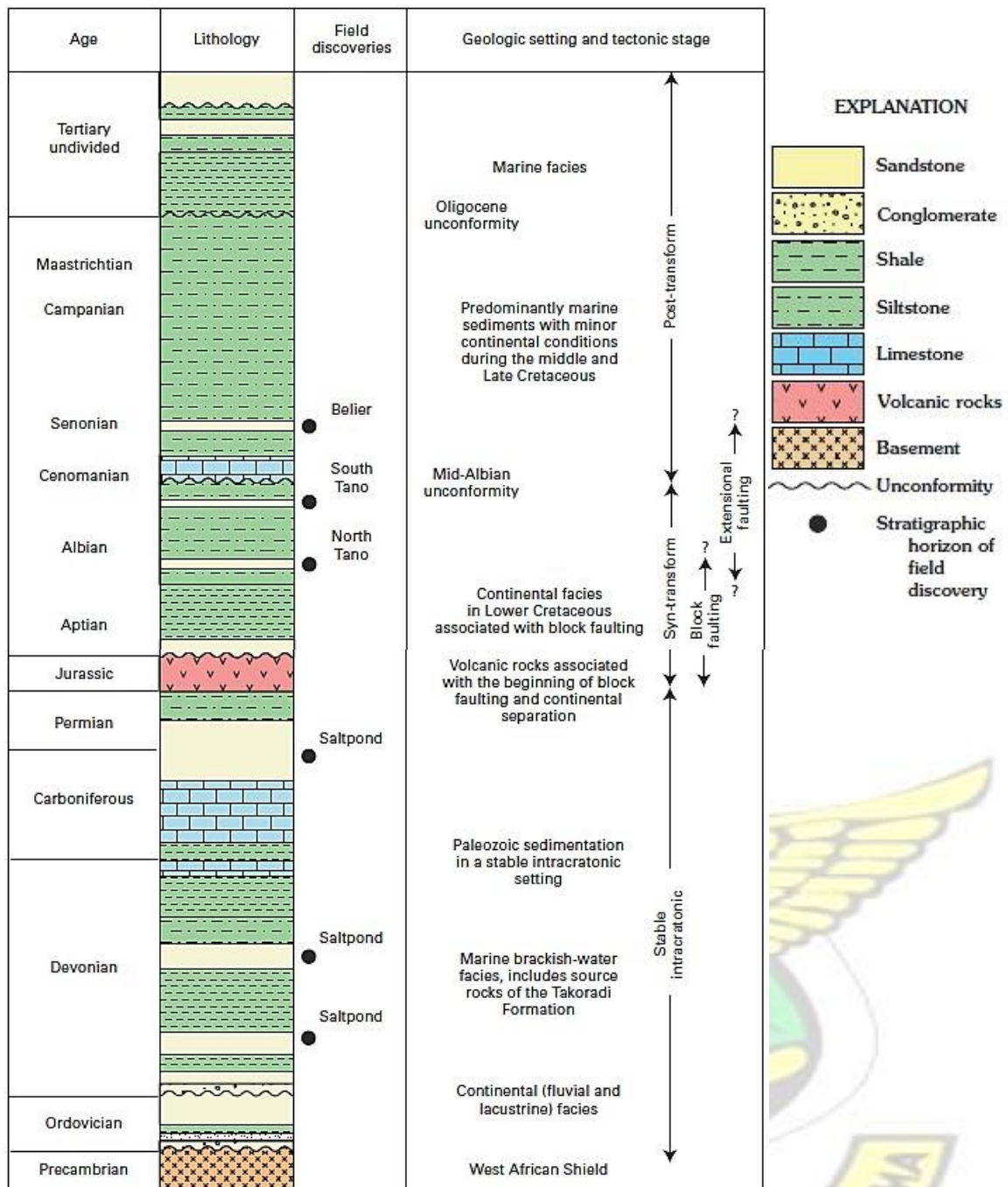


Figure 2.39 Generalized composite stratigraphic column for offshore and onshore parts of Saltpond and Tano Basins, Ghana, Gulf of Guinea Province (Brownfield and Charpentier, 2006). Modified from Tucker. Cretaceous stage boundaries were not shown by Tucker (1992),

From the figure above, it is evident that the North and South Tano basin fall within the syn and post-transform stage respectively and the lithology of the stratigraphic layer within which they fall is predominantly siltstone. The stratigraphic horizon of discovery is however relatively thin compared to that of the Saltpond basin.

Figure 2.40 gives a closer look at the lithology of the exact formation of the reservoir of interest in the research study area (the Santonian formation in the Upper Cretaceous era).

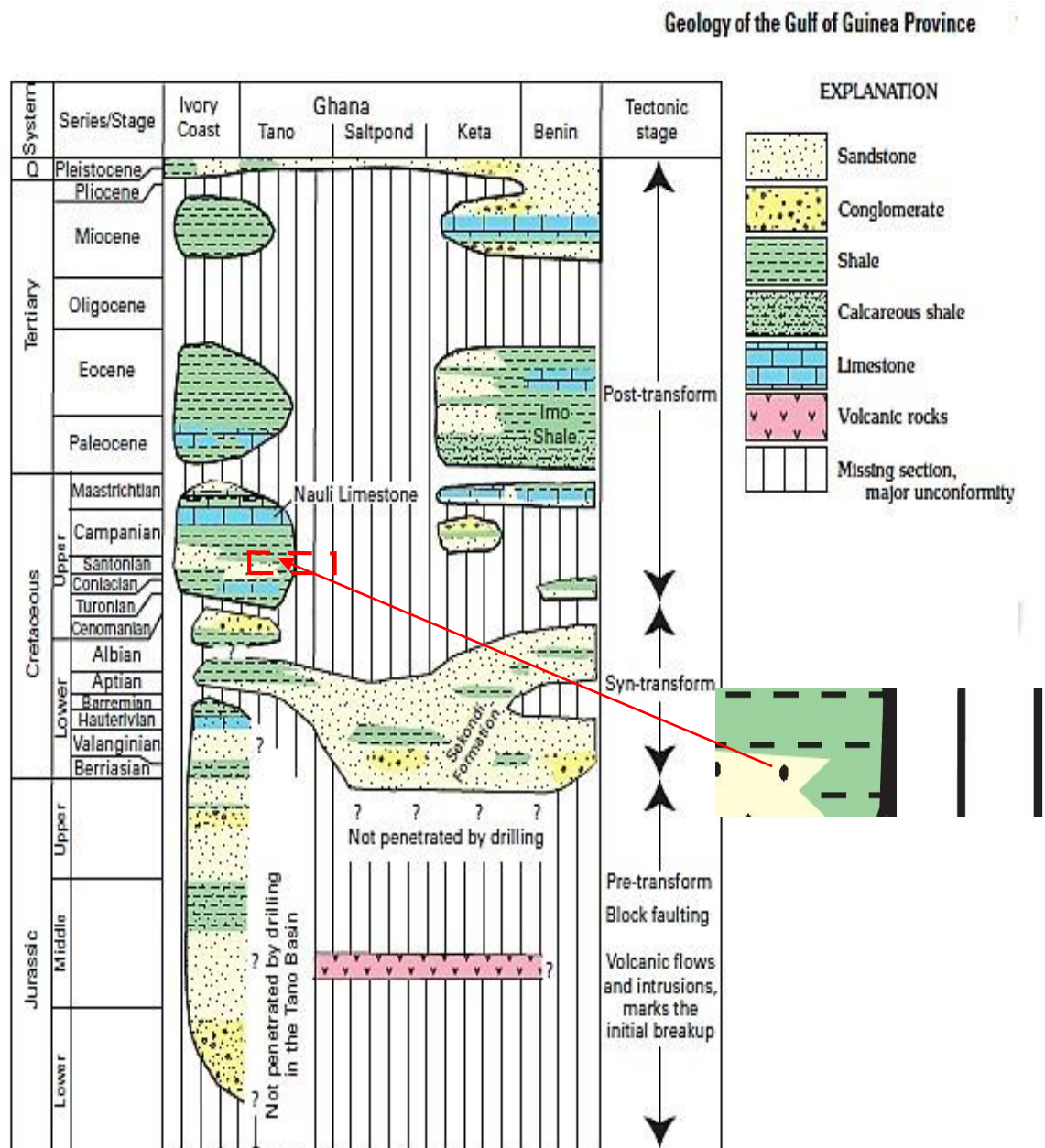


Figure 2.40 Generalized stratigraphic column showing age, lithology, tectonic stage and stratigraphic position of selected formations in major basins of the Gulf of Guinea Province (Brownfield and Charpentier, 2006). Modified from Kjemperud et al.,1992.

From Figure 2.40, two main types of lithologies fall within the Tano Basin. These are shale and sandstone. There is also a region of major fault demarcated by the missing section in the form of an unconformity.

2.2.10.2 Stratigraphy of the Tano Basin

The Tano Basin falls within the Cretaceous age and until 2008 contained 62 drilled wells- including appraisal wells and shallow onshore boreholes (Sutherland, 2008).

The larger portion of the Tano basin is located offshore with just a little land extension.

The Tano Basin began its tectonic sedimentary evolution from a wrench-modified extensional rift basin. This rifting was initiated by complex movements resulting from the separation of the continents between the South American and African plate- that brought about the creation of the Tano Basin within the Atlantic Ocean.

It is speculated by Atta-Peters and Kyorku, (2013) that a thermal anomaly with subsequent uplift occurred at the margin of the newly created African and Brazilian continental plates in the Tano area. This uplift occurred in late Albian time and may be the plate tectonic model for the development of the Tano structural trend.

Rock Deposition in the Tano basin began in the Aptian ages of the early Cretaceous era. This has been an area of focus for clastic sediment deposition from the African continent and consequently, been a major target for oil and gas exploration since 1896.

Within the Tano Basin, three main play systems have been identified. These are the Albian play, the Cenomanian Play and the Turonian play. The Turonian play has proven to be the most productive of the field with huge discoveries such as the Jubilee and TEN field (Atta-Peters and Garrey, 2014).

Stratigraphically, the Tano basin starts with the deposition of sandstone with a mix of shale during the early Aptian age. This formed the basement rock at a depth of around 2134 m to 2743 m (Atta-Peters and Salami, 2004).

It was then followed by another shale deposition (the B-shale series) during the early Albian age. This B-shale is considered to be the most important system in the Tano

basin, since it was found in most of the wells drilled across it. It is also believed to have served as the main source rock in the basin (Atta-Peters and Salami, 2004).

Following the B-shale deposition, a layer of sandstone was deposited and now serves as a reservoir rock. Due to the presence of oil in this rock, it is assumed that the migration period for the oil generated from the source rock into the reservoir rock was very short (Atta-Peters and Salami, 2004).

The sandstone deposition was then proceeded by a breakup in sedimentation. There was a subsequent uplift and erosion event during the upper Albian age which signified a major unconformity in the basin (Atta-Peters and Salami, 2004).

Next, Cenomanian shale was deposited and after that came sandstone mixed with huge deposits of limestone. These events took place during the Cenomanian age (Atta-Peters and Salami, 2004).

In the Turonian to Upper Santonian time zone, medium brownish -grey shales and claystone, often non-fossiliferous, with occasional dolomite or limestone were deposited. The deposition has a general thickness of about 280 meters and most of the plays in the offshore Tano falling within this region have commercial accumulations of hydrocarbons (Atta-Peters and Salami, 2004).

Later, during the Campanian ages, there was a further deposition of a shale-rich layer mixed with occasional stringers of dolomite and limestone at a sedimentation rate of 127 ft/million yrs (i.e. 38.71 m) (Atta-Peters and Salami, 2004).

Following that came the Maastrichtian section. This was made up of a relatively thin depositional layer of claystone with an occasional occurrence of sandstone and dolomite (Atta-Peters and Salami, 2004).

The Middle and Lower Eocene stratigraphic section was formed from finely laminated dark grey/brown claystone with thin beds of fossiliferous dolomite and fine sandstone.

Large portions of the Upper Eocene, Paleocene and Oligocene section are either only present as a thin bed or completely absent. This is attributed to extensive uplift and erosion associated with the Alpine Orogeny (Atta-Peters and Salami, 2004).

Several river systems contributed significant clastics to the deep basin and led to deposition of large turbidite fan/channel complexes. As a result of the burial during the Upper Cretaceous period, and further subsidence and burial during the Tertiary, hydrocarbons were generated in the axial part of the basin, charging the traps already in place (Atta-Peters and Salami, 2004).

2.2.10.3 Geology of the Upper Cretaceous System

Much of onshore Ghana is comprised of metamorphosed sedimentary and volcanic rocks over 2,000 million years old. The offshore Western Tano Basin is however primarily Mesozoic and dominated by Cretaceous and younger sediments deposited during and after the continental rift (Brownfield and Charpentier, 2006). Figures 2.41 and 2.42 represent the divisions of geologic time and the subdivision of the Cretaceous system respectively.

Cenozoic era (present–66.0 Mya)	Quaternary (present–2.58 Mya)
	Neogene (2.58–23.03 Mya)
	Paleogene (23.03–66.0 Mya)
Mesozoic era (66.0–252.17 Mya)	Cretaceous (66.0–145.0 Mya)
	Jurassic (145.0–201.3 Mya)
	Triassic (201.3–252.17 Mya)
Paleozoic era (252.17–541.0 Mya)	Permian (252.17–298.9 Mya)
	Carboniferous (298.9–358.9 Mya)
	Devonian (358.9–419.2 Mya)
	Silurian (419.2–443.8 Mya)
	Ordovician (443.8–485.4 Mya)
	Cambrian (485.4–541.0 Mya)
Precambrian supereon (541.0 Mya–4.567 Gya)	Proterozoic (541.0 Mya–2.5 Gya)
	Archean (2.5–4 Gya)
	Hadean (4–4.567 Gya)

Figure 2.41 Divisions of geologic time— major chronostratigraphic and geochronologic Units (Gradstein et al.,2004)

System/ Period	Series/ Epoch	Stage/ Age	Age (Ma)
Paleogene	Paleocene	Danian	younger
Cretaceous	Upper/ Late	Maastrichtian	66.0–72.1
		Campanian	72.1–83.6
		Santonian	83.6–86.3
		Coniacian	86.3–89.8
		Turonian	89.8–93.9
		Cenomanian	93.9–100.5
	Lower/ Early	Albian	100.5–~113.0
		Aptian	~113.0–~125.0
		Barremian	~125.0–~129.4
		Hauterivian	~129.4–~132.9
		Valanginian	~132.9–~139.8
		Berriasian	~139.8–~145.0
Jurassic	Upper/ Late	Tithonian	older

Figure 2.42 *Subdivision of the cretaceous system (Cohen et. al,2015)*

Continental rifting- which propagated northwards from the South Atlantic- formed a continuous anoxic seaway in the West African Transform Margin from the Late Albian to Turonian age (CGG, 2014). This led to the deposition and preservation of organic matter, which now forms the Basin's lacustrine Upper Albian, Cenomanian and Turonian source rocks.

During the Upper Cretaceous era, a thick clastic sequence consisting of fluvial and lacustrine facies was deposited. This sequence, in addition to the thin Tertiary section, provided adequate thickness to mature the Cretaceous source rocks in the central and western region of the Tano Basin (Atta-Peters and Garrey, 2014).

Ideal conditions for the deposition of a thick source rock in the Cenomanian (Late Cretaceous) age occurred because of the rapid drowning of the West African transform margin. The onshore creation of a deep basin with significant river systems led to the deposition of large channel/turbidite fan complexes- forming stratigraphic oil traps in deep water (Brownfield and Charpentier, 2006).

During the Cenomanian age, the entire West African margin was rapidly inundated, and thick organic-rich shales were deposited over a wide area, forming another important source horizon for hydrocarbons (Atta-Peters and Salami, 2006). Their maturity was a matter of debate until recently, when discoveries confirmed them to emanate from this level.

The Santonian formation (within which the reservoir in the research study was formed) is a part of the Apollonian formation. The Apollonian formation overlies the Birimian Precambrian basement rocks and collectively represents the formations in the Upper Cretaceous System- from Cenomanian to Campanian (Kitson,1928). It is comprised of the Cretaceous-Eocene marine sedimentary rocks and occurs in the eastern portion

of a crescent-shaped basin- along the coast of the Atlantic Ocean- in the SW corner of the country. The onshore geology is constituted of alternating clays, sands and limestones with gentle dips overlying the Precambrian metamorphosed Birimian System (which is composed of phyllite, schist and greywackes). At greater depths, there is an increased compactness and intrusion of sands and clays into the sandstones and shales. Nodules of marcasite or pyrite are common in the clays and shales. The only prominent stratigraphic marker of the formation is a series of thin, highly fossiliferous limestones, known in the geological literature as Naulilimestone (Yendaw, 2005).

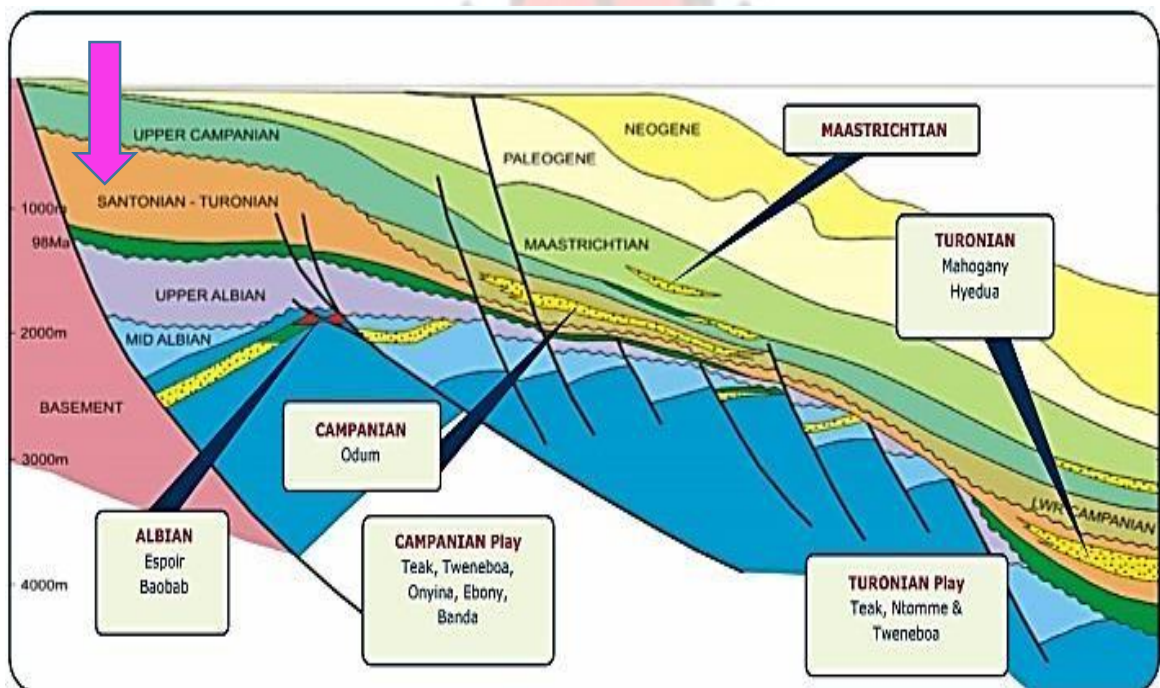


Figure 2.43 Geological section of the Tano Basin illustrating the main play types (Sutherland, 2008)

Figure 2.43 is an illustration of the various geological play types in the Tano Basin.

Paleozoic rocks observed in the Tano Basin are Lower Carboniferous siliciclastic The only rocks (Tucker, 1992). Seismic data has indicated that this sequence is underlain by strata equivalent to the Ordovician and Devonian rocks in the onshore part of the Saltpond Basin and the offshore part of the Keta Basin.

CHAPTER 3 METHODOLOGY

Figure 3.1 gives a general outline of the various steps that were required to attain the research objectives.

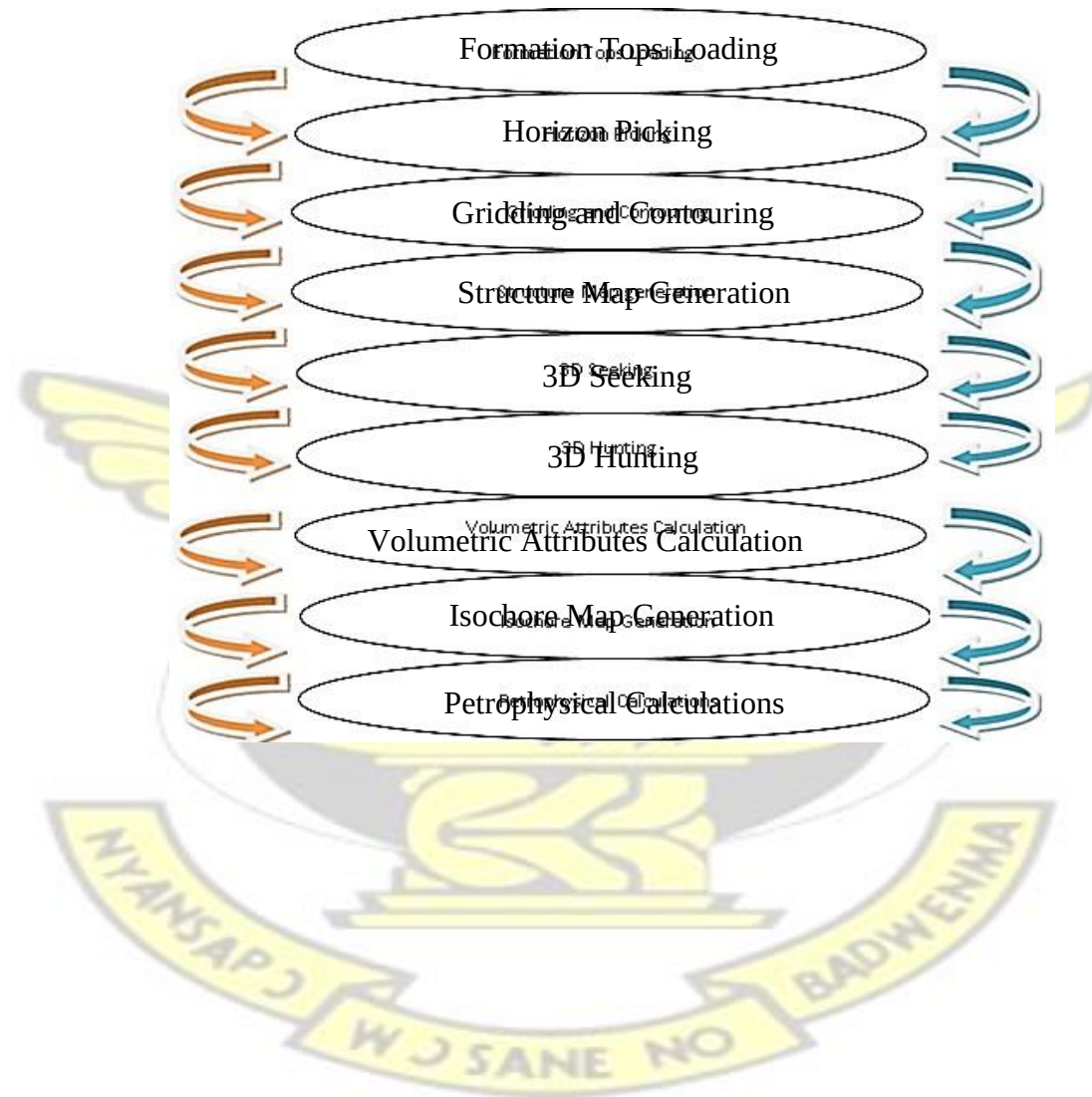


Figure 3.1 Methodology

workflow

3.1 DATA LOADING

3.1.1 Loading Data and Formation Tops into Kingdom SMT

Formation tops are the depths in a well (measured in meters below a reference elevation) at which the top of formations are found in the subsurface. This applies to all geological formations with the exception of the glacial drift formations- where the formation top is actually located at the bottom or base of the drift.

With information from the End of Well (EOW) reports, the formation top locations from the drilled wells were loaded into the software and superimposed on the seismic sections (Figure 3.2). The loaded tops were from Time-Depth (TD) charts which ensured that all the formation tops were positioned at the correct depth in the correct geological time.

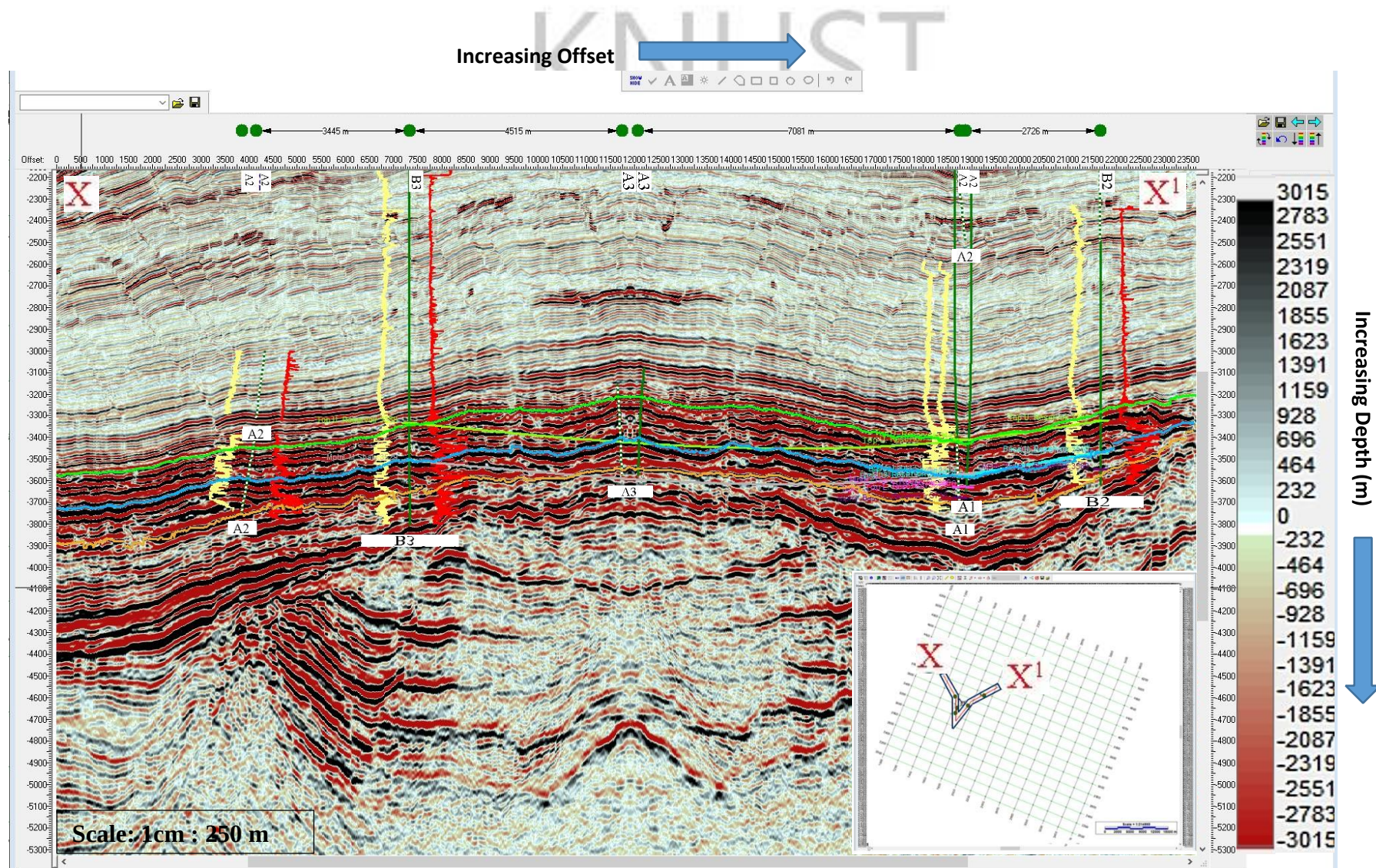


Figure 3.2 Arbitrary line showing well to well correlation of the formation tops across several wells

KNUST



3.1.2 Horizon Picking

A horizon is the surface separating two different rock layers, i.e. the reflection from this surface. Horizon picking involves marking the reflector passing through the formation top (or as closely as possible to it) using the 2D Fill, 2D Hunt and Manual horizon picking parameters. The European polarity convention was applied in horizon picking, thus the positive values represented the peaks and the negatives the troughs. A total of four horizons (Figure 3.4) named Seabed, Top Upper Reservoir (which represents the top of the reservoir of interest), Middle Shale (which represents the top of the middle shale layer) and Base of Reservoir (which represents the base of the reservoir of interest) were picked on each seismic section in the inline and crossline directions. A picking interval of 10 between the inlines and crosslines in the polygon grid on the base map yielded horizon picks on 148 inline seismic sections and 200 crossline seismic sections for each horizon. This generated a grid such as the one in Figure 3.3 for each horizon.

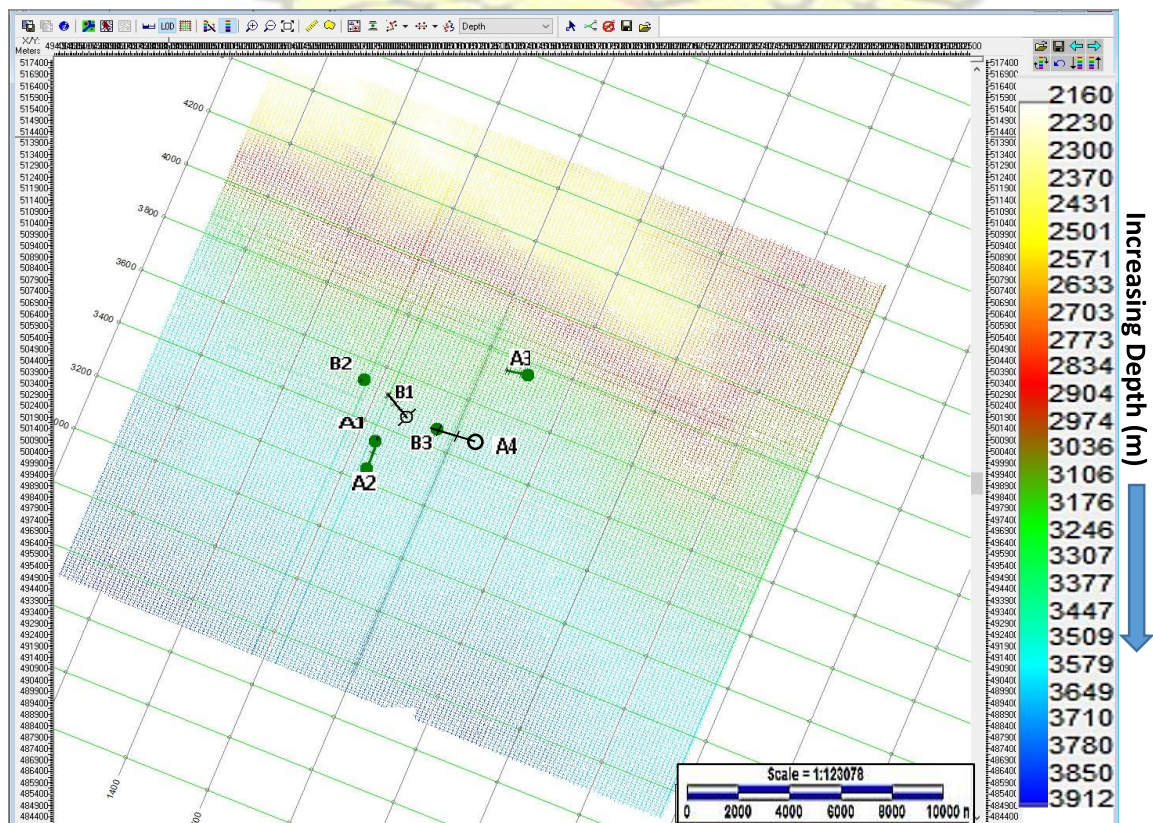


Figure 1.3 Top Upper Reservoir horizon grid



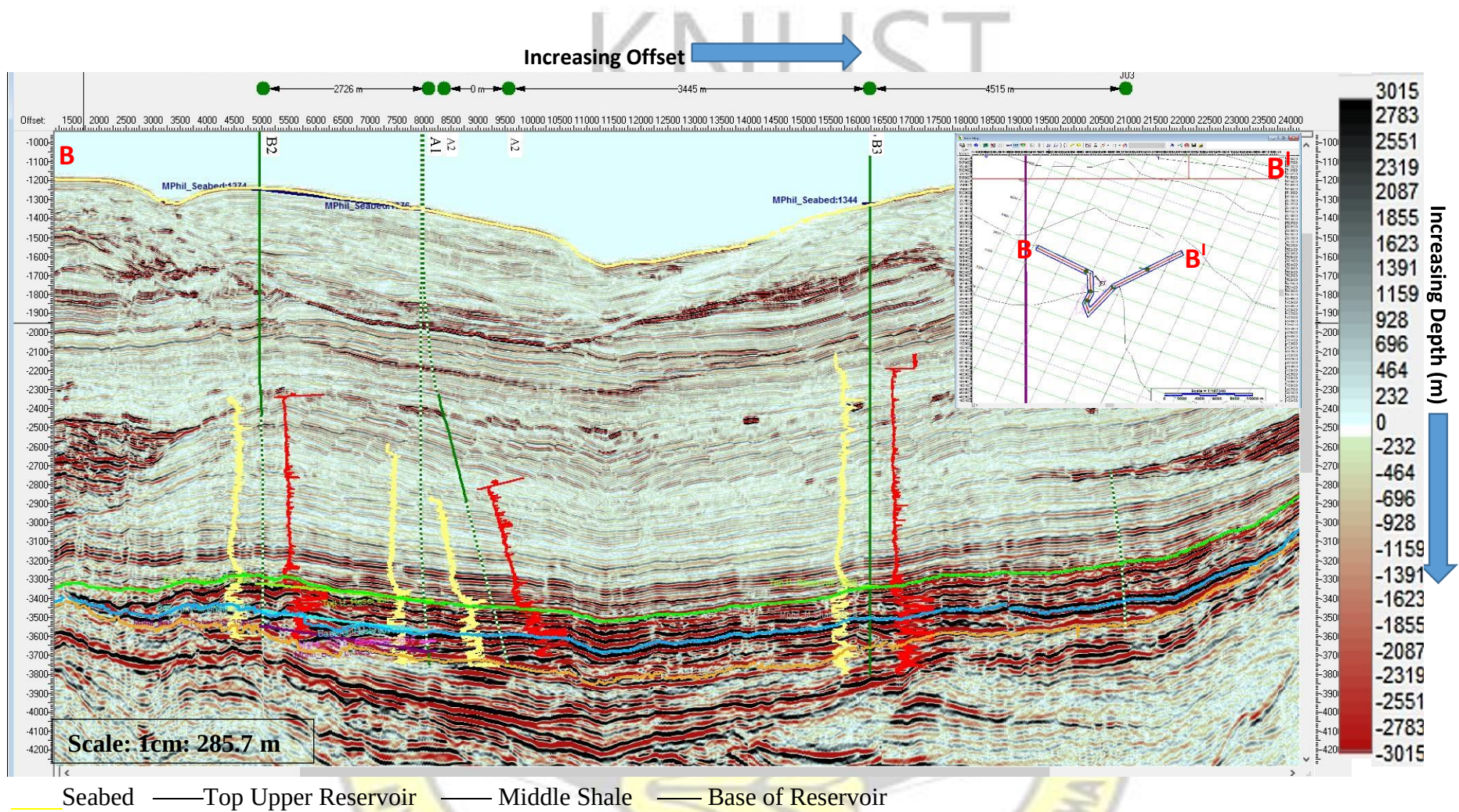


Figure 3.4 Arbitrary line showing all four horizons

KNUST



3.2 DATA MAPPING

3.2.1 Gridding

A top structure depth map generated from a depth conversion is most commonly used for two tasks: providing a depth prognosis to the Top Reservoir prior to drilling; and in the calculation of gross rock volume (GRV) for use in the determination of the hydrocarbons initially in place (HIIP).

With the aid of the Grid Data toolbar (Figure 3.5), grids were generated for each horizon using the Flex Gridding algorithm. This was done to interpolate the depth values within the intervals between the inlines and crosslines on which the horizons had been picked. The gridding input parameters were the horizon name, the gridding algorithm, the grid colour, the polygon area within which the grid should be constrained and the output grid name.

The screenshot shows the 'Grid Data' dialog box with the following settings:

- Data and Algorithm** tab is selected.
- Input**:
 - Category: Horizon
 - Search: (empty)
 - Filter: (empty)
 - Reset: (button)
 - Allow only one selection: (checked)
 - Selected item: HORIZON::MPhil_Base L. Reservoir latest version :De
- Parameters**:
 - Gridding algorithm: Flex Gridding
 - Residual fit to data: (unchecked)
 - Constrain new grid to the parameters of an existing grid and/or polygon:
 - Do not constrain by grid: (selected)
 - Same AOI and grid cell size: (unchecked)
 - Constrain by polygon: Untitled22 (Worlanyo)
 - Digitize...: (button)
 - Inside polygon: (selected)
 - Outside polygon: (unchecked)
- Output**:
 - Grid name: Mphil top upper final version
 - Color: LightYellow
 - Description: (empty)
 - View grid when done: (checked)
 - Desired units label: Time (radio), TVD Seismic (radio), Subsea (radio), Other: (radio)
 - New...: (button)
- Grid template**: Save (button), Load (button), Compute relevant parameters from input: (checked)
- Buttons at the bottom: Clear All, OK, Cancel, Apply, Help

Figure 3.5 Data gridding toolbar

3.2.2 Contouring and Structure Map Generation

Contour maps were then generated from the horizon grids to facilitate the visual interpretation of the depth variation across the grid. This was done with the help of the Kriging algorithm in the Contour Parameters toolbar (Figure 3.6).

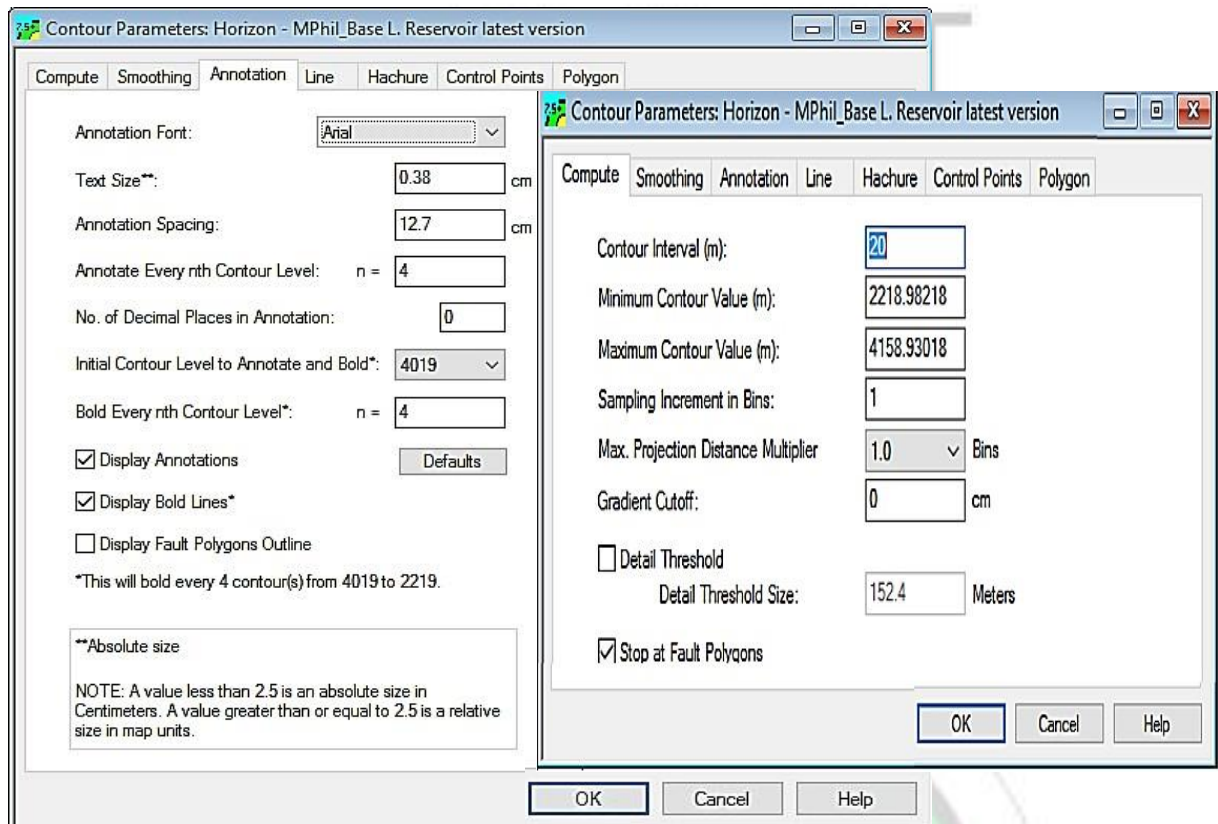


Figure 3.6 Contour Map parameter toolbar

Here the contour interval and number of decimal places was specified on the compute and annotation tabs respectively. The 'no smoothing' option was selected in the smoothing tab in order to prevent the introduction of errors into the work. The VuPAK module was then used to generate a 3D structure map of each horizon.

3.2.3 3D Seeking

The picking parameters toolbar (Figure 3.7) was used to fill the spaces between the horizon inlines and crosslines with data interpolated from the picked lines. It resulted

in a significant reduction of the blank spaces in the map and made it possible to view the amplitude response of the depth volume data.

Picking Parameters

Horizon picking mode

Type: 3D Seeker Data type: Regular Data type events: Peak

Guide window options

☒ Show a guide window

Use active horizon color

Time: 0.02 Depth: 200 Length: 0.02 (s) 200 (m)

Criteria to stop picking

☒ Input seismic data: $\leq$ 0

☒ Vertical shift: $\geq$ 0.05 (s) 50 (m)

☒ Correlation: $\leq$ 0.9

☒ Confidence: $\leq$ 0.1

Correlation window length:

Time: 0.1 Depth: 250 Upper: 0.1 Lower: 0.1 (s) 250 (m)

Peak and trough event behavior

Use: Detect relative

Snapping adjustment for doublets: Do not adjust

Other options

☐ Stop at visible fault surface intersections ☒ Update map and vertical displays

☐ Apply a Bandpass Filter

Snap to

Sample

Polygon options

Pick: Inside by: Using an existing polygon

Untitled22

Start 3D Seeker OK Cancel Apply Help

Figure 3.7 3D Seeking picking parameters toolbar

3.2.4 3D Hunting

3D Hunt was also done to further reduce the remaining voids using the Horizon Picking Parameters toolbar (Figure 3.8).

Picking Parameters

Horizon picking mode

Type: 3D Hunt Data type: Regular Data type events: Peak

Guide window options

☒ Show a guide window

Use active horizon color

Time: 0.02 (s) Length: 0.02 (Z value)

Depth: 15 (m)

Criteria to stop picking

Threshold: Length:

☐ Amplitude: 0

☐ Correlation: 0

Peak and trough event behavior

Use: Detect relative

Dip behavior: Prefer least dip

Other options

☐ Stop at associated fault polygon set ☒ Update map and vertical displays

☐ Apply a Bandpass Filter

☐ Stop after 1 failed picks

Polygon options

Pick Inside by Using an existing polygon

Untitled22

Start 3D Hunt OK Cancel Apply Help

Figure 3.8 3D Hunt picking parameters toolbar

3.2.5 Attribute Mapping

3.2.5.1 Volume Attributes

For volumetric analysis, attribute maps were first generated using the *Vatmin*, *Vatmax* and *Vatrms* functions for the interval between the Top Upper Reservoir and the Middle Shale, in order to determine which of the three algorithms best identified the reservoir presence and quality. This was done using the volume attribute calculator toolbar (Figure 3.9) of the Kingdom SMT Software.

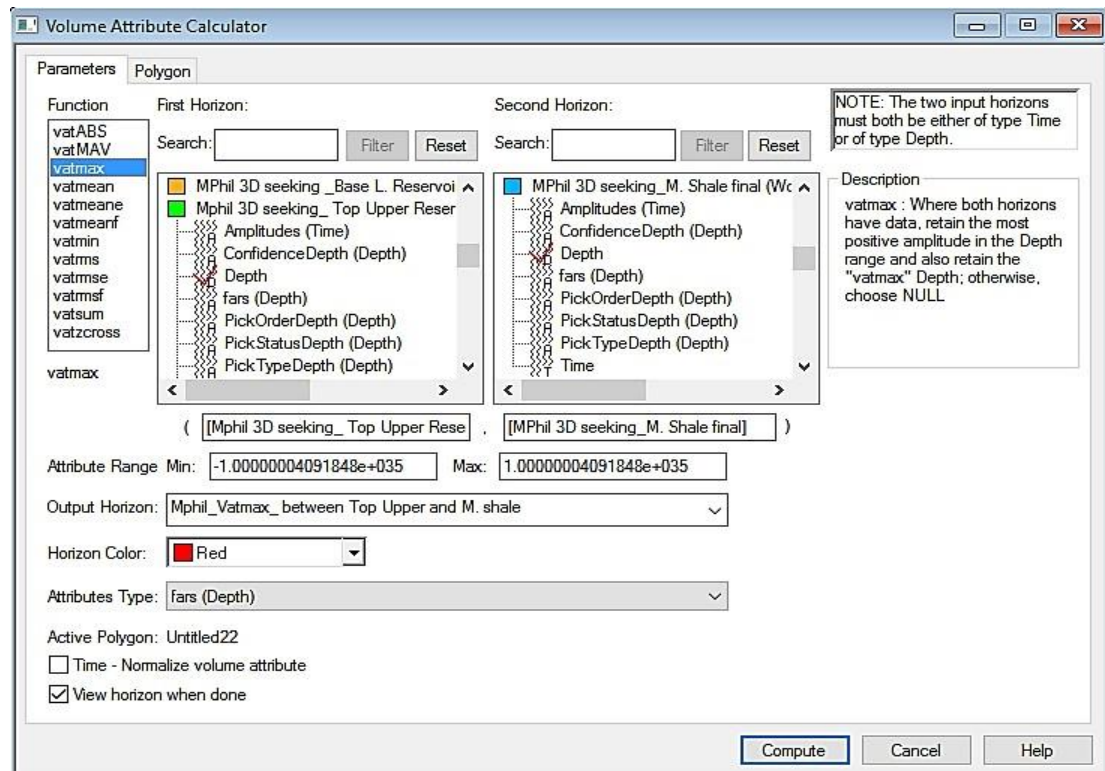


Figure 3.9 Volume attribute calculator toolbar

In the volume attribute calculator toolbar, the function (whether *vatmax*, *vatmin* or *vatrms*) was inputted, followed by the name of the upper and lower horizon boundaries, the colour and attribute type, as well as the name of the polygon within which the calculation should be carried out.

When it was determined that *vatrms* yielded the best reservoir response, it was repeated using the ‘nears’ and subsequently the ‘fars’ as the desired attribute output type.

This was done to determine whether generating the volume amplitude attributes in the nears produced better reservoir responses than generating them in the fars. It was concluded that the best volume amplitude map images could be generated from the use of the *vatrms* function with the fars as the desired attribute output type. These two input parameters were then used to calculate the volume attributes for all the intervals in the reservoir zone.

The horizon data was then exported into the EEI volume and the same process was repeated.

3.2.5.2 Isochore (True Vertical Thickness) Map Generation

Using reservoir response from the EEI volume, a polygon was digitized around the region which produced relatively high amplitude responses for the vatmin map between the Top Upper Reservoir and Middle Shale. Using the Math on Two Maps Calculator (Figure 3.10), the Isochore map was then generated for that polygon in order to facilitate gross sand volume determination for petrophysical parameters calculation (through the multiplication of the thickness map by the polygon surface area).

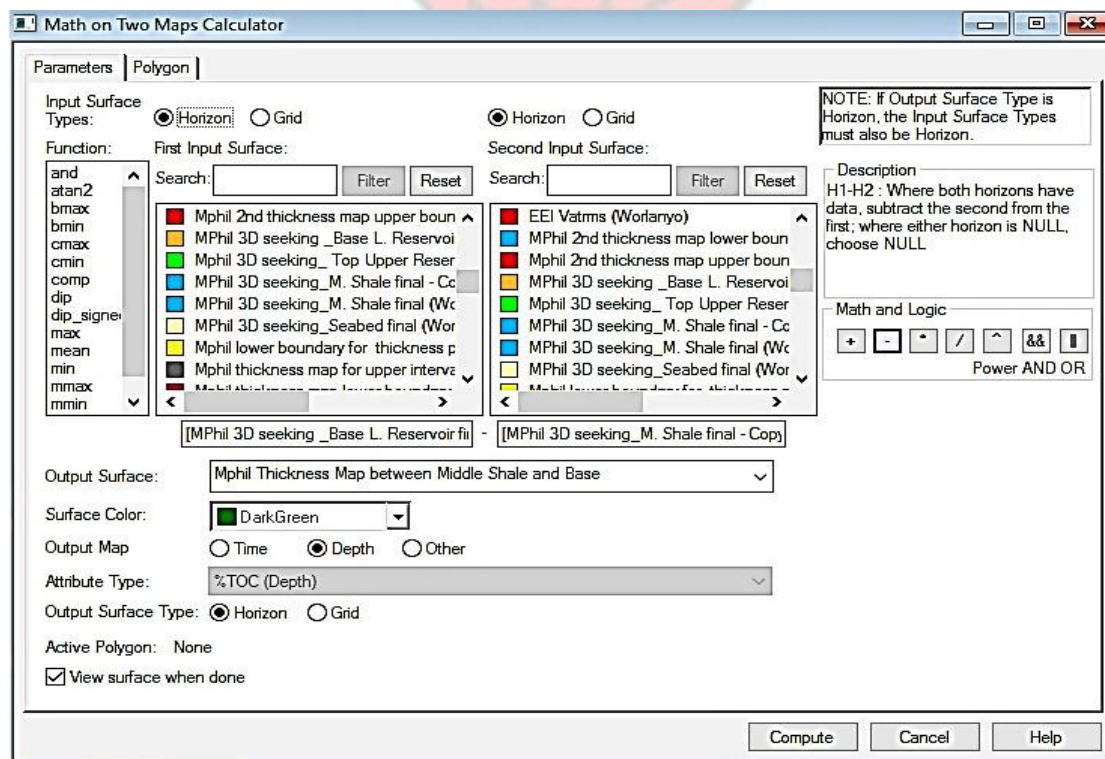


Figure 3.10 Math on Two Maps calculator toolbar

Figure 3.11 shows the options that were selected in the Output Grid Parameters toolbar

Re-grid: Choose Output Grid Parameters

☐ Set new output grid parameters
☒ Set to input grid Mphil_polygon grid for middle shale (for the polyg)
☐ Set to input grid Mphil_polygon grid for top upper final version par.

	Minimum:	Maximum:	Increment:
X (Meters):	492184	530920	8
Y (Meters):	482592	519808	8

Resample Gridding Algorithm*: Bilinear Resampler

*The selected resample algorithm here will preserve any NULL area in the input grid when regridding.

OK Cancel Help

Figure 3.11 Math on Two maps output grid parameter selection

3.3 PETROPHYSICAL CALCULATIONS

3.3.1 Polygon Digitization

With the aid of the arbitrary line passing through all the wells and showing all the *vatrms* map intervals (refer to Figure 4.42 on page 138), the upper (Top Upper Reservoir and Middle Shale) and lower (Middle Shale and Base of Reservoir) intervals were identified as the intervals which fully captured (i.e. did not cut through) the sand packages that had positive hydrocarbon indicators on their resistivity log. In order to isolate the sand packages localised around the wells, polygons were constructed around the stronger amplitude reflections using the Digitize Polygon option on the base map tool bar. These polygons were named UP (Upper Polygon) and LP (Lower Polygon) respectively. Although some of the maps showed larger and stronger amplitude responses at certain points they were not selected as areas for polygon digitization because they were not tested by any well. Selecting these areas would have made it difficult to calculate the reservoir parameters without the help of well logs.

Polygon Structure and Thickness Mapping

In the PSDM seismic data, the Structure and Isochore maps of the horizons for the polygon in the upper and lower interval of the *vatrms* maps were generated for petrophysical analysis. Due to the fact that the depth variation across both Isochore maps was fairly heterogeneous as a result of the structural and stratigraphic trapping features, the gross sand volume for each polygon could not (as previously desired) be calculated from the multiplication of the Isochore map by the polygon surface area. Therefore, for accurate results, empirical calculations had to be carried out with the help of log readings from the Gamma Ray, Resistivity, Neutron density and porosity logs.

3.3.2 Log Readings

The procedure used to read the log values and obtain all the required input parameters for petrophysical analysis are briefly described in the steps below.

1. The upper and lower boundary of the reservoir interval within which the calculations would be done (i.e. depth locations of the Top Upper Reservoir and Middle Shale) was identified and marked on the log sections of the composite well logs for well B3 in UP.
2. The GR log was used to identify the lithology and determine whether the intervals identified consisted of shale, sandstones, shaly sands or clean sands based on the log curve deflections and their corresponding interpretation.
3. The gross sand apparent thickness value was calculated by recording and summing the thickness in terms of depth of every sand interval (irrespective of whether it contained hydrocarbons or not) between the upper and lower boundaries of UP, and converted to meters using the scale provided on the log header.
4. The zones of interest (hydrocarbon bearing sand zones) were marked on the log sections based on GR curve kicks to the left- at a cut off of 50%- with corresponding resistivity curve deflections to the right. The net sand thickness

value, or the sum of the apparent thickness of all the clean hydrocarbon-bearing sand intervals, was recorded using the procedure described in the previous step.

5. The crossover between the neutron porosity and density curves was used to identify the exact portion of the hydrocarbon bearing sands that was comprised of only hydrocarbons (oil). The total volume of gas log and the magnitude of the porosity-density curve crossover was checked to ensure that the crossovers observed did not occur due to the presence of gas.
6. The average porosity value was then read off the curve by taking the mid- point of the crossover zones for each hydrocarbon interval, summing the values and subsequently converting the result to porosity units using the log scale provided.
7. The entire process was repeated for LP in the lower interval using well A2.

3.3.3 Parameter Calculations

All the equations used to calculate the petrophysical parameters in this section (equation 3.1 – 3.9) were obtained from GNPC. Figure 3.12 shows how to delineate the gross interval, gross sand, net sand and net pay using the log cut offs.

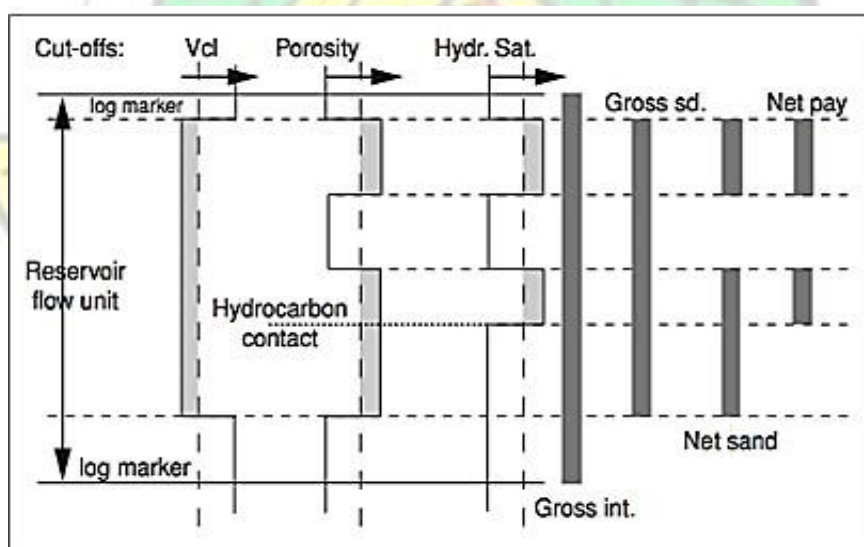


Figure 3.12 Net pay determination (Odainkey,2015)

The legend for Figure 3.12 is given below:

- **Gross Interval** - Interval from top to base of reservoir flow unit

- **Gross Sand** - Interval satisfying shale cut-off criteria
- **Net Sand** - Satisfies shale and porosity cut-off criteria
- **Net Pay** - Satisfies shale, porosity and saturation cut-off criteria
- **Net to Gross Ratio** – Refers to Net sand/Gross interval

3.3.4.1 Gross Rock volume

In any subsurface trap, the Gross Rock Volume (GRV) parameter is the most influential parameter that is used in the determination of the potential concentration of the reservoir, or in the determination of the estimation and magnitude of the resource volume. It is defined as the product of the accumulation of the grid cell area and the Z-Value associated with the grid as follows:

Gross Volume = Area * Z-value, where Z-value is the value within the area specified by the grid or limited by the planimeter polygon.

In the Kingdom SMT software, GRV can be calculated using the Volumetric toolbar (Figure 3.13).

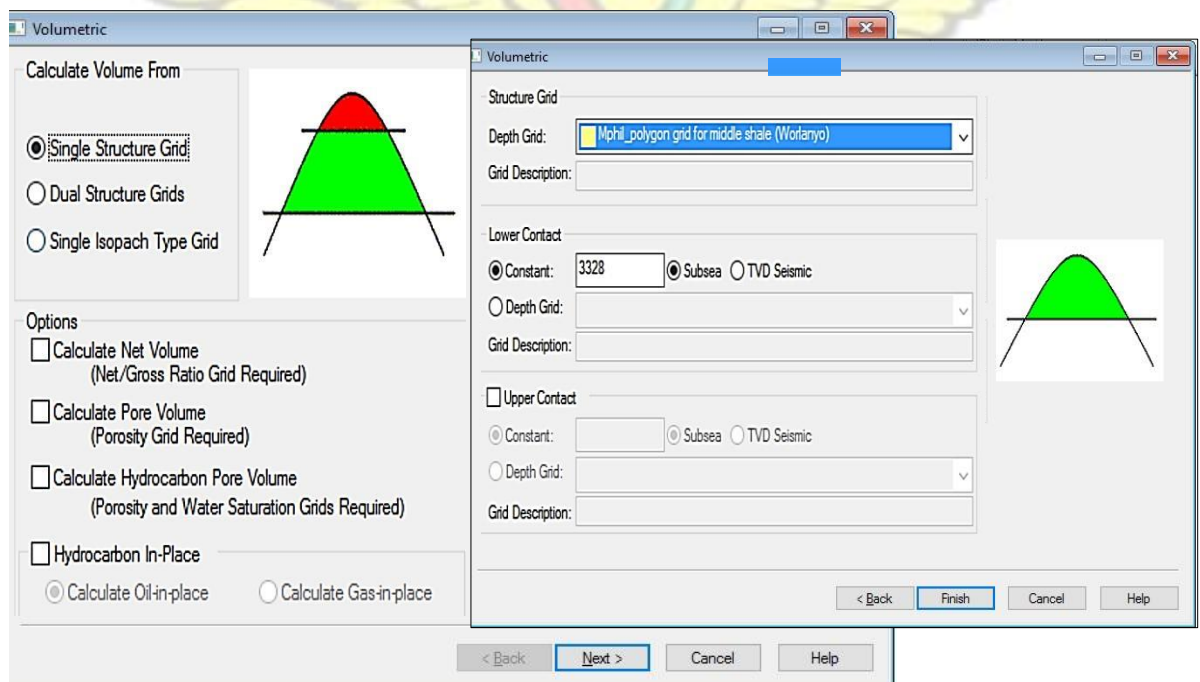


Figure 3.13 Gross Rock Volume calculator toolbar

The calculation can be done from a single structure grid with the option of calculating the net volume. The polygon name and structure grid is selected as input, and the

oilwater contact value as the lower boundary for the GRV calculation. For this research however, it was calculated by multiplying the polygon area by the gross sand thickness obtained from the log.

3.3.4.2 Gross Sand Volume

The total surface area of UP was recorded from the size of the digitized polygon provided by the Kingdom SMT software.

The gross sand volume was determined by multiplying the sum of the apparent sand thicknesses recorded for every sand interval by the total surface area of UP.

3.3.4.3 Net Sand Volume

The net volume of sand was similarly calculated by multiplying the sum of all the clean sand thickness intervals by the total surface area of UP.

3.3.4.4 Net to Gross Ratio

The Net to Gross ratio N/G was computed by dividing the net sand volume by the gross rock volume

3.3.4.5 Volume of Shale

The volume of shale can be calculated using Archie's Linear equation, based on the assumption that the radioactive potassium elements of the shale were the sole contributors to the gamma ray log reading in the unconsolidated rocks:

Linear Method (Used in consolidated rocks)

$$V_{sh,l} = \frac{GR_{SH} - GR_{CL}}{GR - GR_{CL}} \dots\dots\dots 3.1$$

Where $V_{sh,l}$ = Volume of shale

GR = Gamma ray log reading in zone of interest (API units)

GR_{CL} = Gamma ray log reading in 100% clean zone GR_{SH}

= Gamma ray log reading in 100% shale

However, with the GRV which is the total rock volume of the reservoir (all sands + all shales), and the N/G ratio (which is the fraction of the reservoir occupied by sands only), the Volume of Shale was simply deduced from the equation:

$$V_{sh} = (1 - N_G) \times GRV \dots\dots\dots 3.2$$

Where $(1 - N_G)$ is the fraction of shale in the reservoir.

G

3.3.4.6 Total Average Porosity

This was read off the composite well log from the cross-over zones between the neutron porosity and density logs (i.e. the hydrocarbon zones) within the interval of interest for each polygon. In order to get the average porosity reading, the readings were taken from the midpoint of the cross-over zones for each hydrocarbon interval and the sum of all the readings was converted to porosity units using the log scale to obtain the total average porosity. It is noted that in a clean volume of sand (such as in this case), the total average porosity reading is equal to the effective porosity for the volume.

3.3.4.7 Formation Resistivity Factor

This was calculated using:

$$F = \frac{a}{m \phi_e} \dots\dots\dots 3.3$$

Where F = formation resistivity factor

a = the tortuosity factor

ϕ_e = effective porosity (which is the total average porosity value in this case)
 m = the cementation exponent

3.3.4.8 Water Saturation

This was calculated for the zones that appeared to be hydrocarbon bearing using the (Archie, 1942) equation. Under ideal conditions, water saturation may be obtained from logs but other sources include measured formation water samples (DST or SFT), produced water samples, or simply local reservoir history.

For every clean formation, the water saturation was calculated using:

$$S_w^n = \frac{F R_t}{R_w} \dots\dots\dots 3.4$$

or alternatively,

$$S_w = \sqrt[n]{\frac{F R_t}{R_w} \phi_m^a} \dots\dots\dots 3.5$$

Where: S_w = water saturation

F = formation resistivity factor

R_t = total resistivity of the hydrocarbon formation

R_w = formation water resistivity

n = saturation exponent

a =

tortuosity factor

ϕ = porosity

m = cementation exponent

3.3.4.9 Bulk Volume of water

This was obtained from:

$$BVW = S_w \times \phi \dots\dots\dots 3.6$$

Where BVW = Bulk volume of water

S_w = Water saturation

$\emptyset$ = effective porosity

3.3.4.10 Hydrocarbon Saturation

The oil saturation as a percent of the pore space was simply calculated using:

$$S_H = S_o = (1 - S_w) \dots \dots \dots 3.7$$

Where S_H = Hydrocarbon saturation

S_o = Oil saturation

S_w = Water saturation

3.3.4.11 Permeability

For a hydrocarbon reservoir to be considered as exploitable without stimulation, its

permeability must be greater than approximately 100 mD (milliDarcys).

Permeability	Pervious				Semi-Pervious					Impervious			
Unconsolidated Sand & Gravel	Well Sorted Gravel		Well Sorted Sand or Sand & Gravel		Very Fine Sand, Silt, Loess, Loam								
Unconsolidated Clay & Organic					Peat		Layered Clay			Unweathered Clay			
Consolidated Rocks	Highly Fractured Rocks				Oil Reservoir Rocks			Fresh Sandstone		Fresh Limestone, Dolomite		Fresh Granite	
κ (cm ²)	0.001	0.0001	10 ⁻⁵	10 ⁻⁶	10 ⁻⁷	10 ⁻⁸	10 ⁻⁹	10 ⁻¹⁰	10 ⁻¹¹	10 ⁻¹²	10 ⁻¹³	10 ⁻¹⁴	10 ⁻¹⁵
κ (millidarcy)	10 ⁺⁸	10 ⁺⁷	10 ⁺⁶	10 ⁺⁵	10,000	1,000	100	10	1	0.1	0.01	0.001	0.0001

Figure 3.14 Ranges of common intrinsic permeabilities (Modified from Bear,1972)

The permeability was obtained from the (Schlumberger, 1997) formula:

$$K = [250 \times \left(\frac{\emptyset^3}{\dots} \right)]^2 \dots \dots \dots 3.8$$

S_w

Where K_e = permeability

S_w = Water saturation

$\emptyset$ = porosity

3.3.4.12 Original Oil in Place

This is obtained from: N

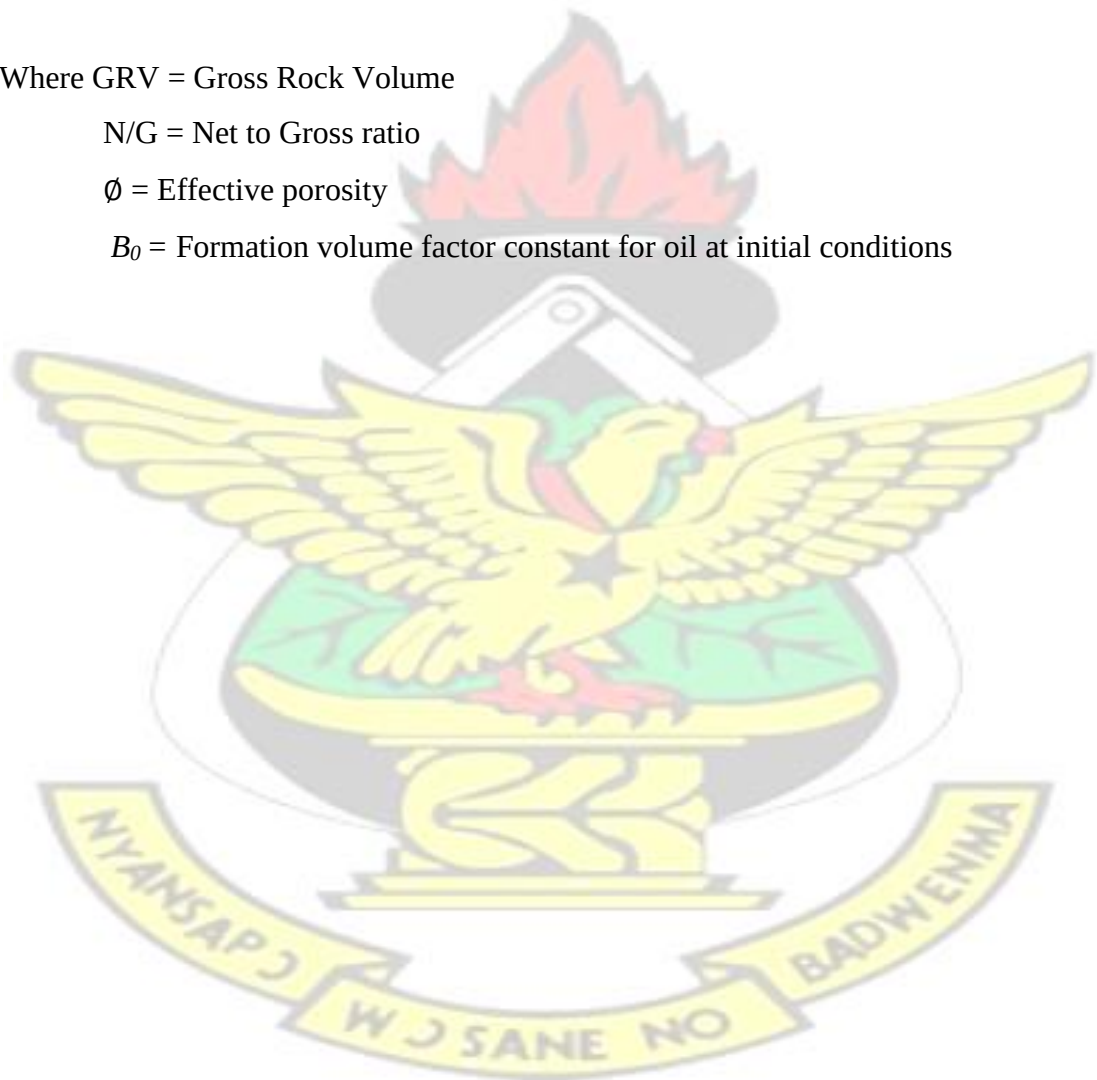
$$OOIP = \frac{GRV \times \frac{N}{G} \times \emptyset \times S^o}{B_o} \dots\dots\dots 3.9$$

Where GRV = Gross Rock Volume

N/G = Net to Gross ratio

$\emptyset$ = Effective porosity

B_o = Formation volume factor constant for oil at initial conditions



CHAPTER 4

RESULTS AND DISCUSSIONS

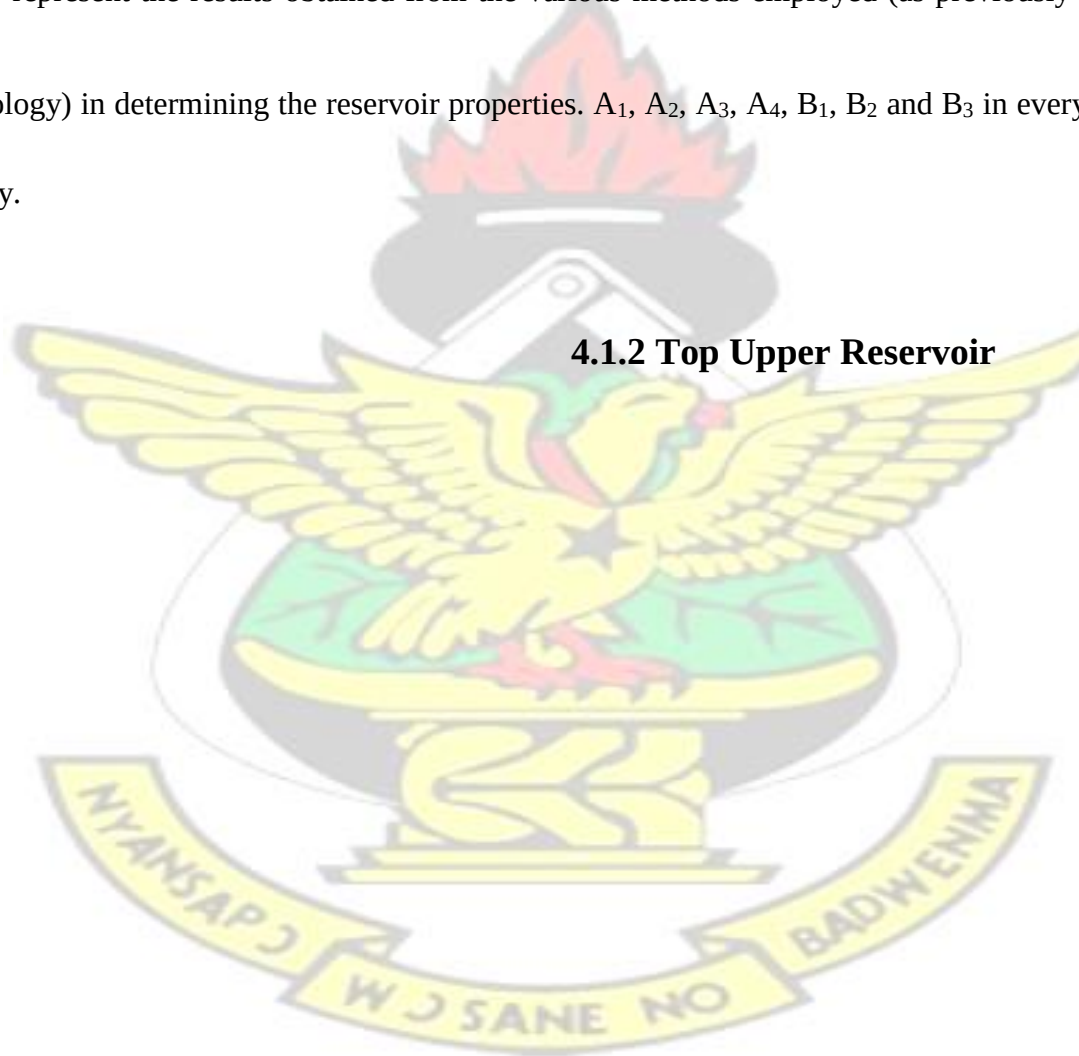
All the figures in this chapter represent the results obtained from the various methods employed (as previously stated in the **RESULTS AND DISCUSSIONS** methodology) in determining the reservoir properties. A₁, A₂, A₃, A₄, B₁, B₂ and B₃ in every figure represent the seven wells being investigated in this study.

4.1 HORIZON GRIDS

4.1 HORIZON GRIDS

4.1.1 Seabed

4.1.2 Top Upper Reservoir



4.1.1 Seabed

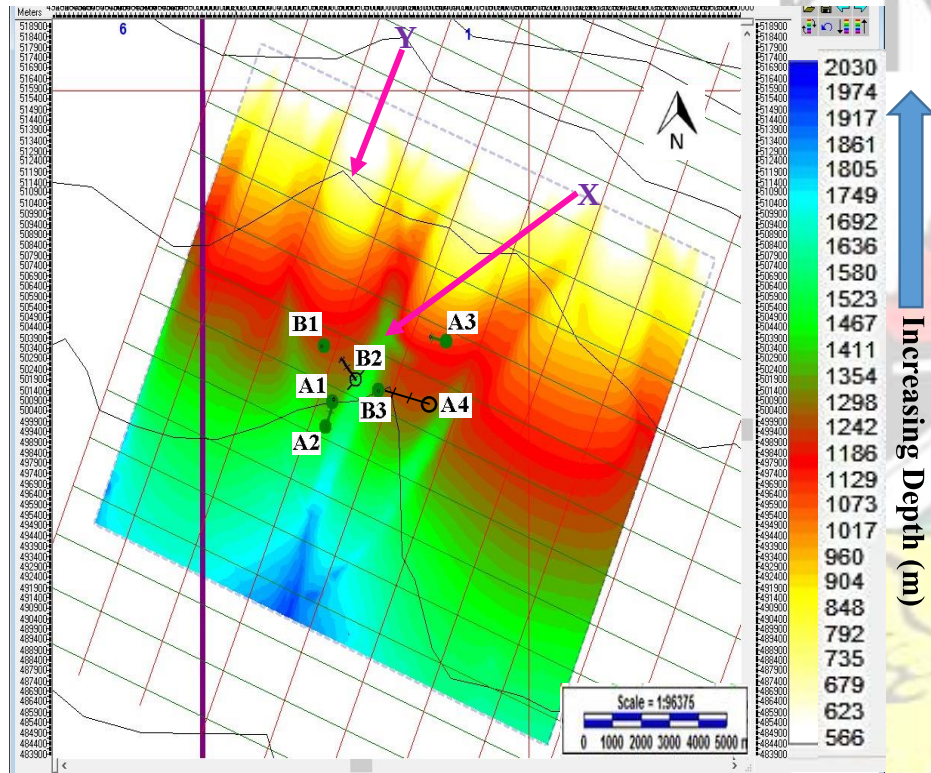


Figure 4.1 Grid of the Seabed

4.1.2 Top Upper Reservoir

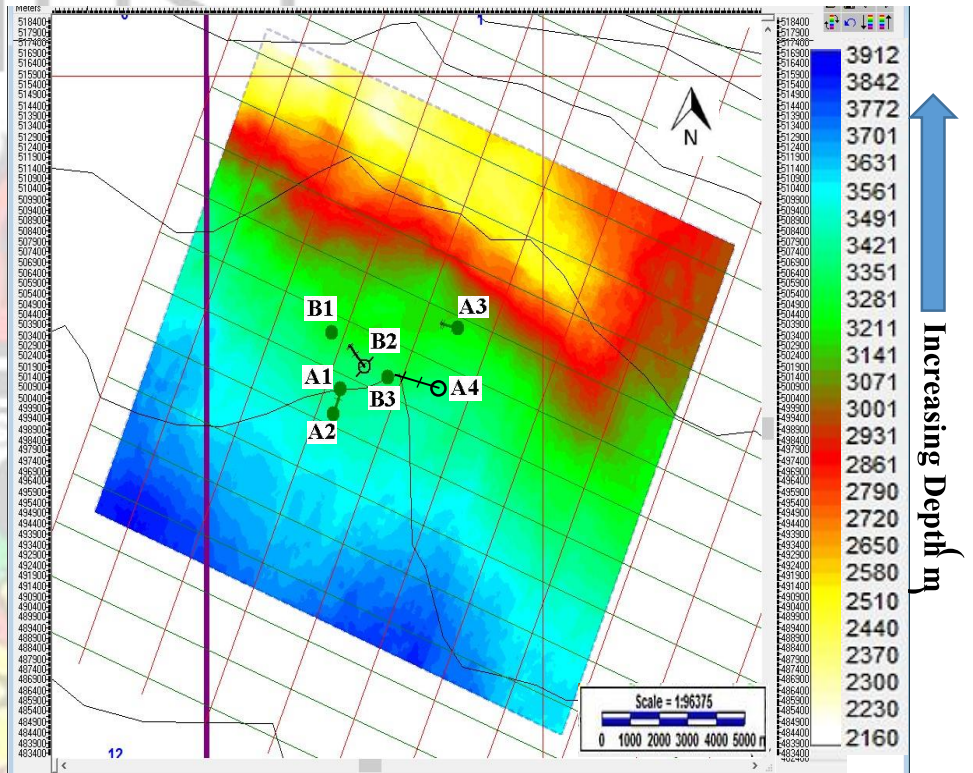


Figure 4.2 Grid of the Top Upper Reservoir

4.1.3 Middle Shale

4.1.3 Middle Shale

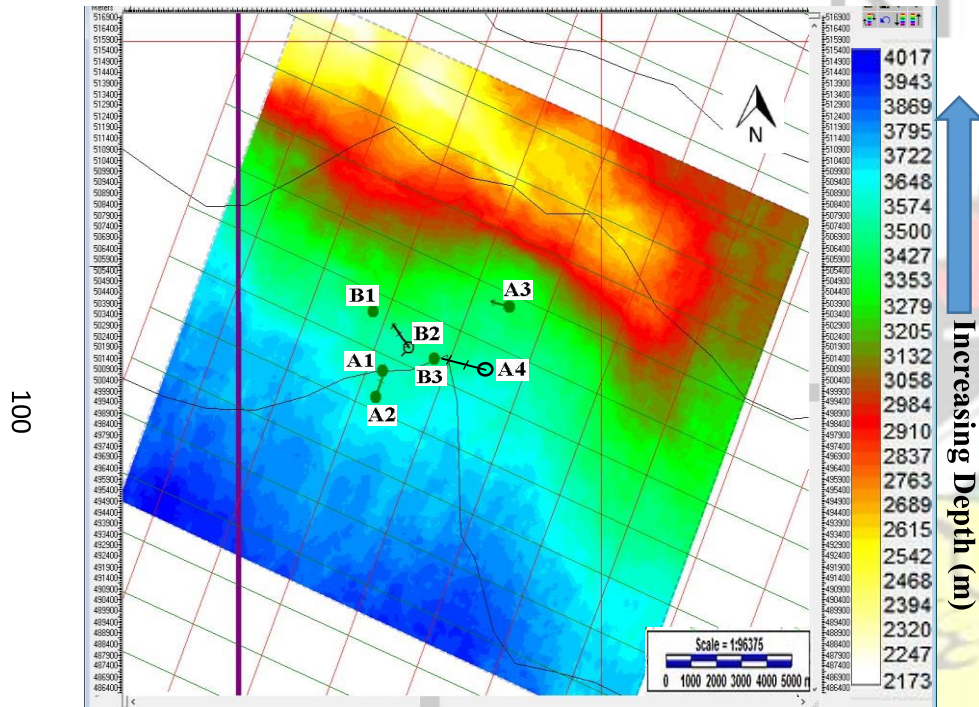


Figure 4.3 Grid of the Middle Shale

4.1.4 Base of Reservoir

4.1.4 Base of Reservoir

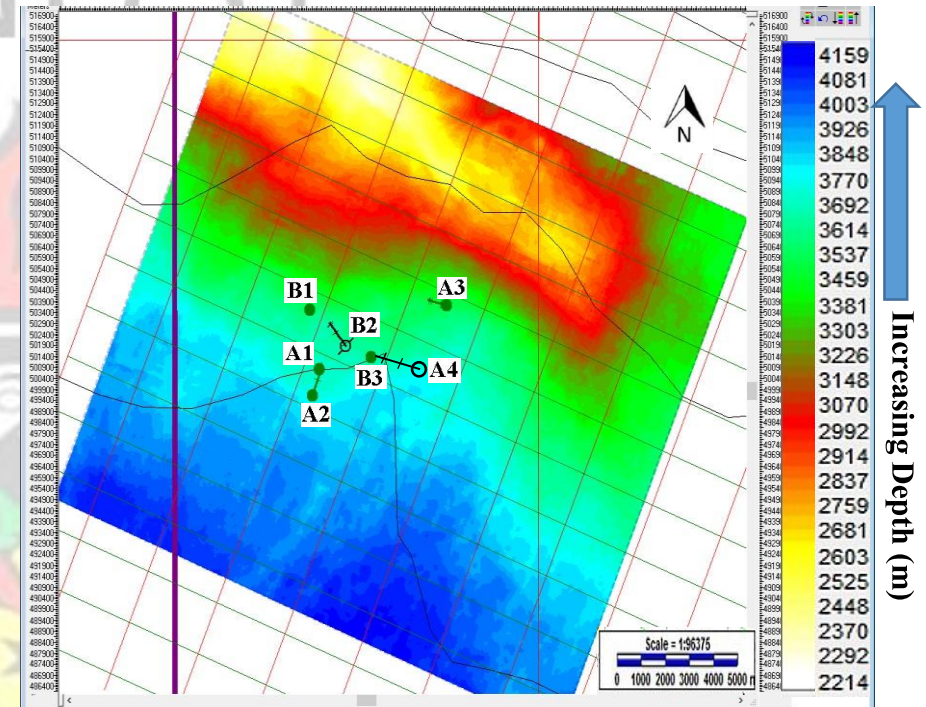


Figure 4.4 Grid of the Base of Reservoir

From Figures 4.1 - 4.4, a general trend of increasing depth in the down dip direction is observed. This could promote the deposition of reservoir sands towards the deepest portions (depo-centers) of the survey area through sedimentary migration from the reservoir source to its point of accumulation under the assistance of deep-sea sedimentation transportation processes. This is made possible by the action of wind and shelf motion such as creep, gliding/sliding, and slumping. On the seabed, finger-like depressions can be identified in the structure's surface. These are indicative of ridges. In between the ridges are canyons (narrow, deep steep-walled sinuous valleys with V-shaped cross sections) which originated from within the continental slope/shelf and were possibly formed as a result of subaerial erosion. The ridges and canyons are denoted by 'X' and 'Y' on Figure 4.1 respectively.

4.2 HORIZON CONTOUR AND STRUCTURE MAPS

4.2.1 Seabed

4.2.1.1 Contour Map

Contour Interval (C.I 20)

4.2.1.1 Contour Map

Contour Interval (C.I 20)

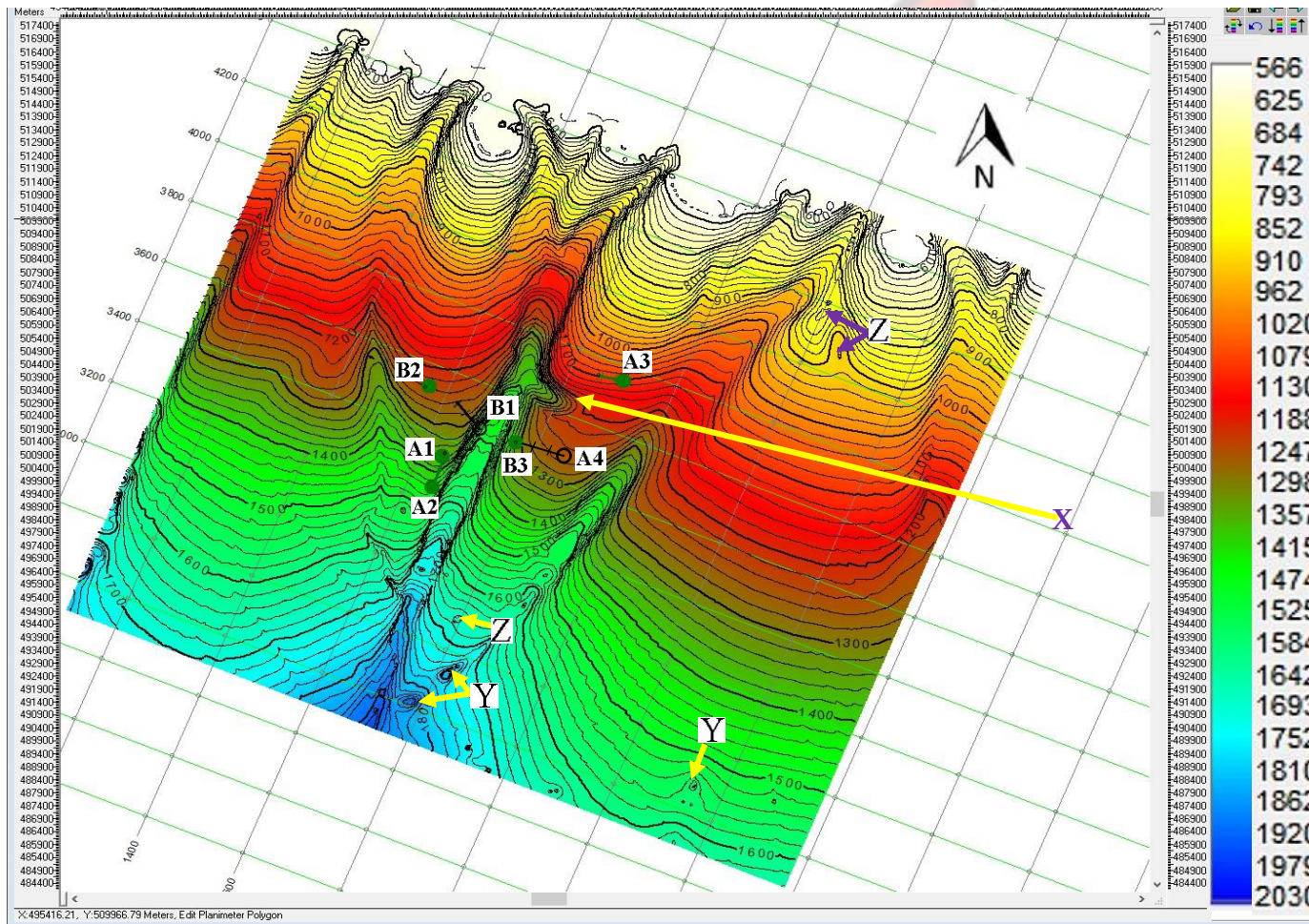


Figure 4.5 Contour map of Seabed

From the contour map, the ridges and canyons are more distinctive. The depth increase is observed to be relatively gradual (from 566 m to 2030 m), as the structural variation at contour intervals of 20 is not that great. There are however additional structures identified in the middle of the central ridge that looks like a lateral projection of the fault ('X'), as well as three anticlines ('Y'). In addition, the contours indicate the possible presence of four way closures ('Z') at three locations on the map. These may serve as possible structural trap locations that favor the accumulation of hydrocarbons.

4.2.1.2 Structure Map

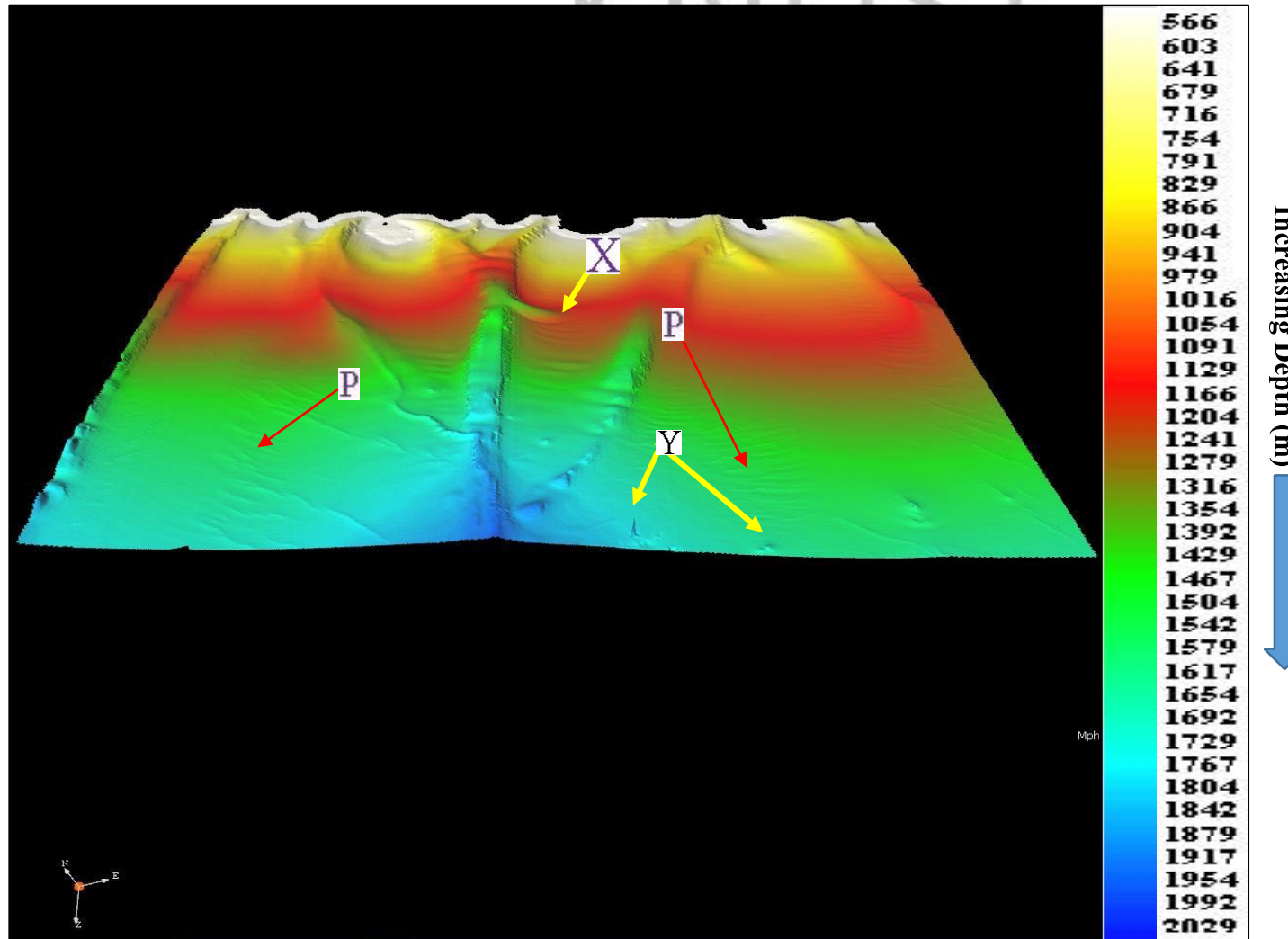


Figure 4.6 3D structure map of Seabed

On the 3D view, faults X and Y stand out clearly.

At 'P', a cluster of what resembles lateral faults can be identified on the extremities of the ridges.

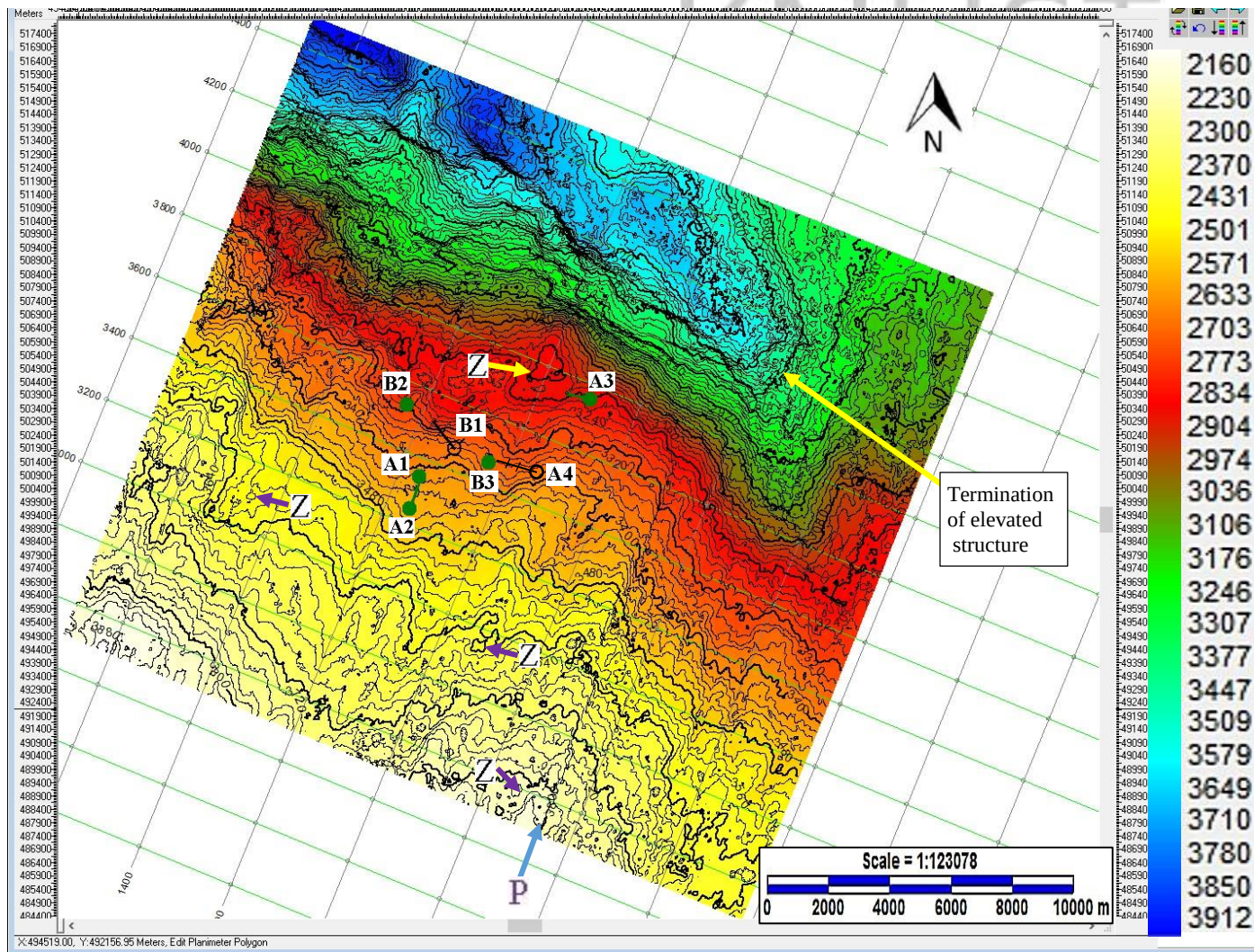
4.2.2 Top Upper Reservoir

4.2.2.1 Contour Map

C.I 20 *Figure 4.7 Contour map of*

C.I 20 4.2.2.1 Contour Map





Top Upper Reservoir

The contours in this map introduce detail into the grid of the Top Upper horizon. At first glance an elevated structure (the blue region) at the top of the map can be seen. It appears to have a deviating effect on the surrounding geological structures which seem to navigate around it. This could probably lead to a change in path of sediment migration causing a reasonably large quantity of reservoir sands to be deposited south-eastward from the source at the top of the map. A n up-close look at the contour map reveals a few four-way closures (Z). Also present is a vertical fault indicating a possible uplift (P).

4.2.2.2 Structure Map

4.2.2.2 Structure Map

104

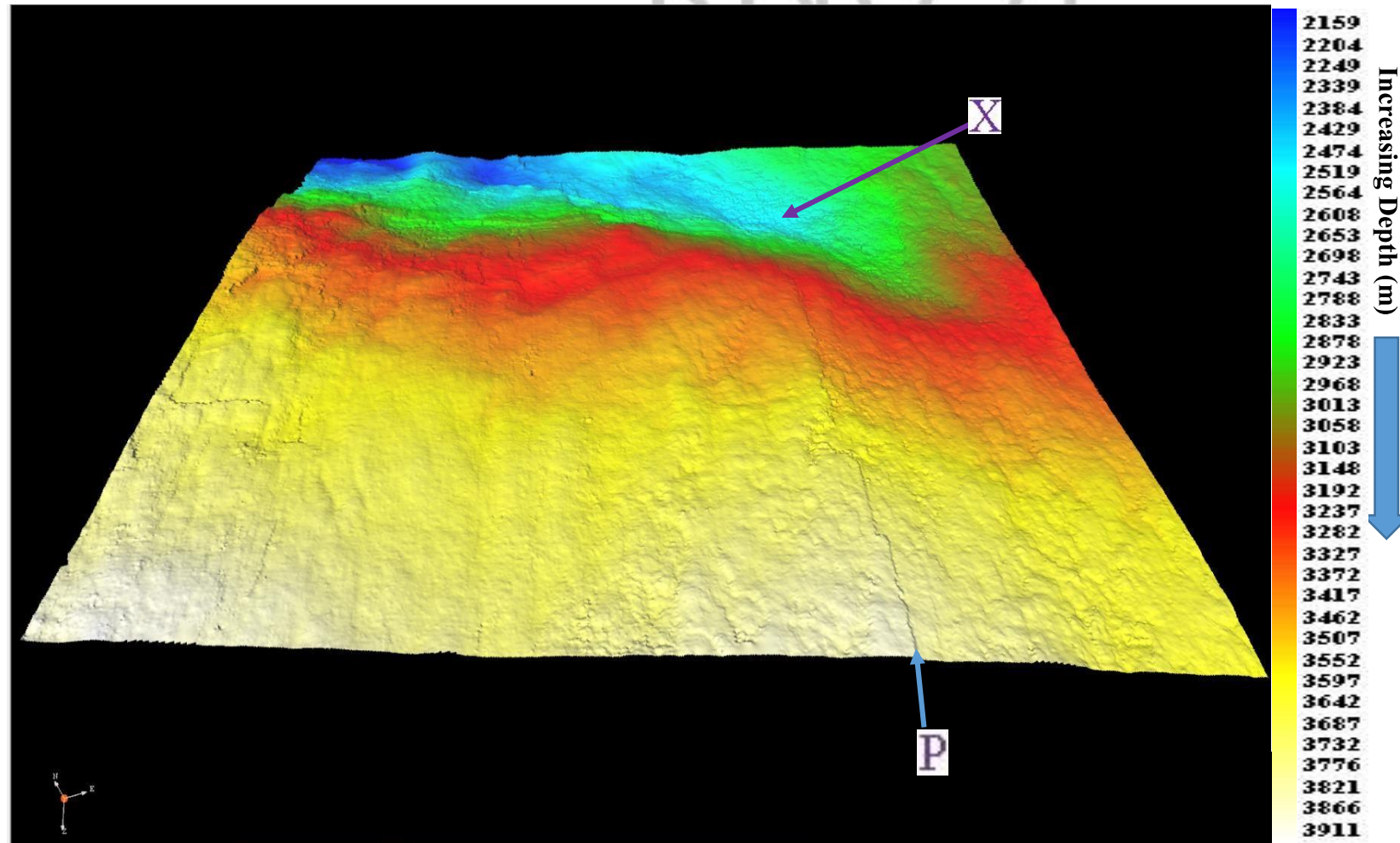


Figure 4.8 3D Structure map of Top of reservoir

Due to the image magnification on this map and the size of the closures present on this horizon, only the vertical fault (P) and the elevated structure (X) can be clearly seen on this map. Depth variations are from 2159 m to 3911 m in the down-dip direction.

4.2.3 Middle Shale

4.2.3.1 Contour Map

C.I 30

4.2.3.1 Contour Map

C.I 30

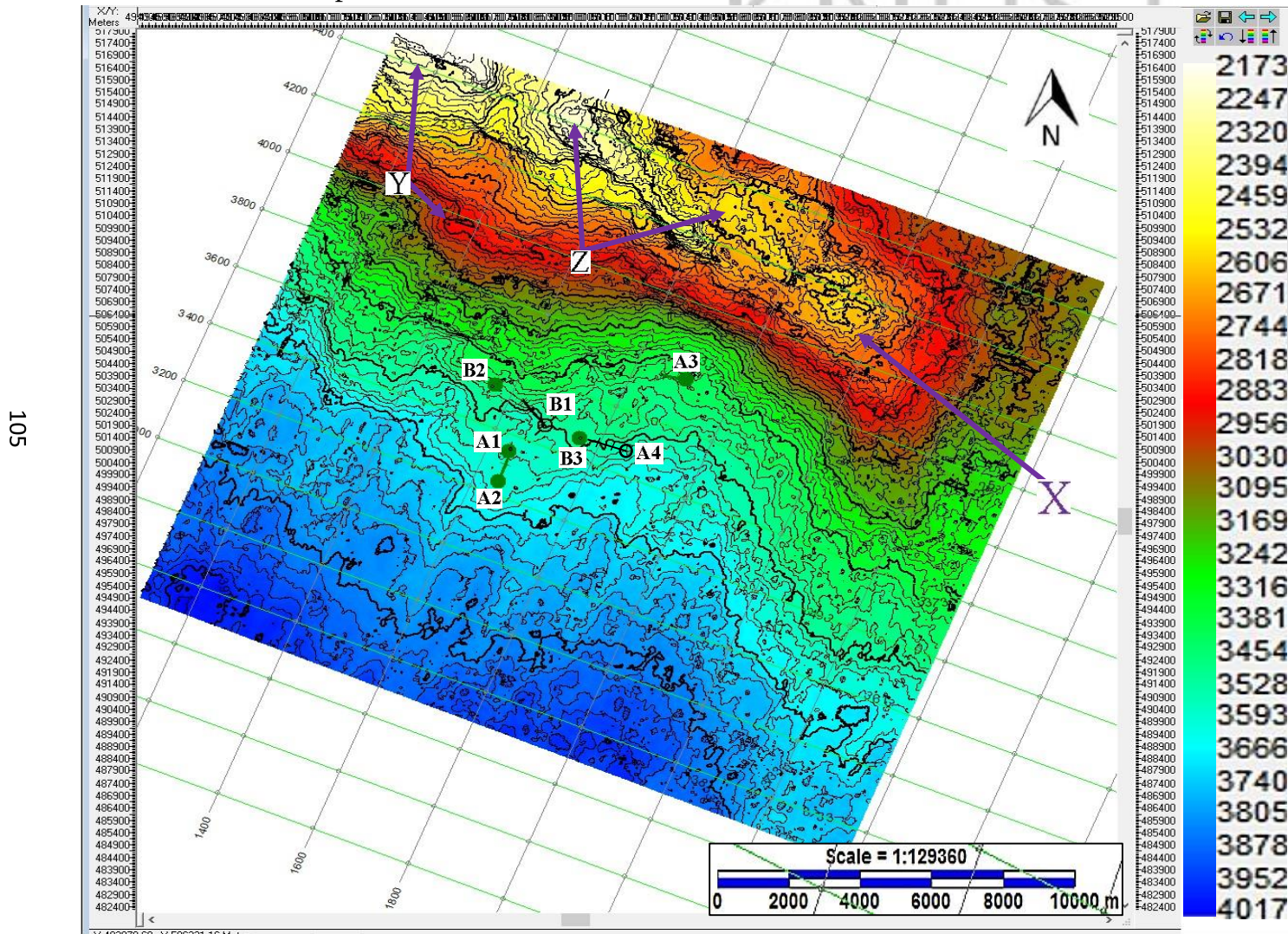


Figure 4.9 Contour map of Middle Shale

This contour map is in many ways similar to Figure 4.8 in terms of the gradational increase in depth downwards from the north-east direction, as well as the elevated structure near the top of the map (X).

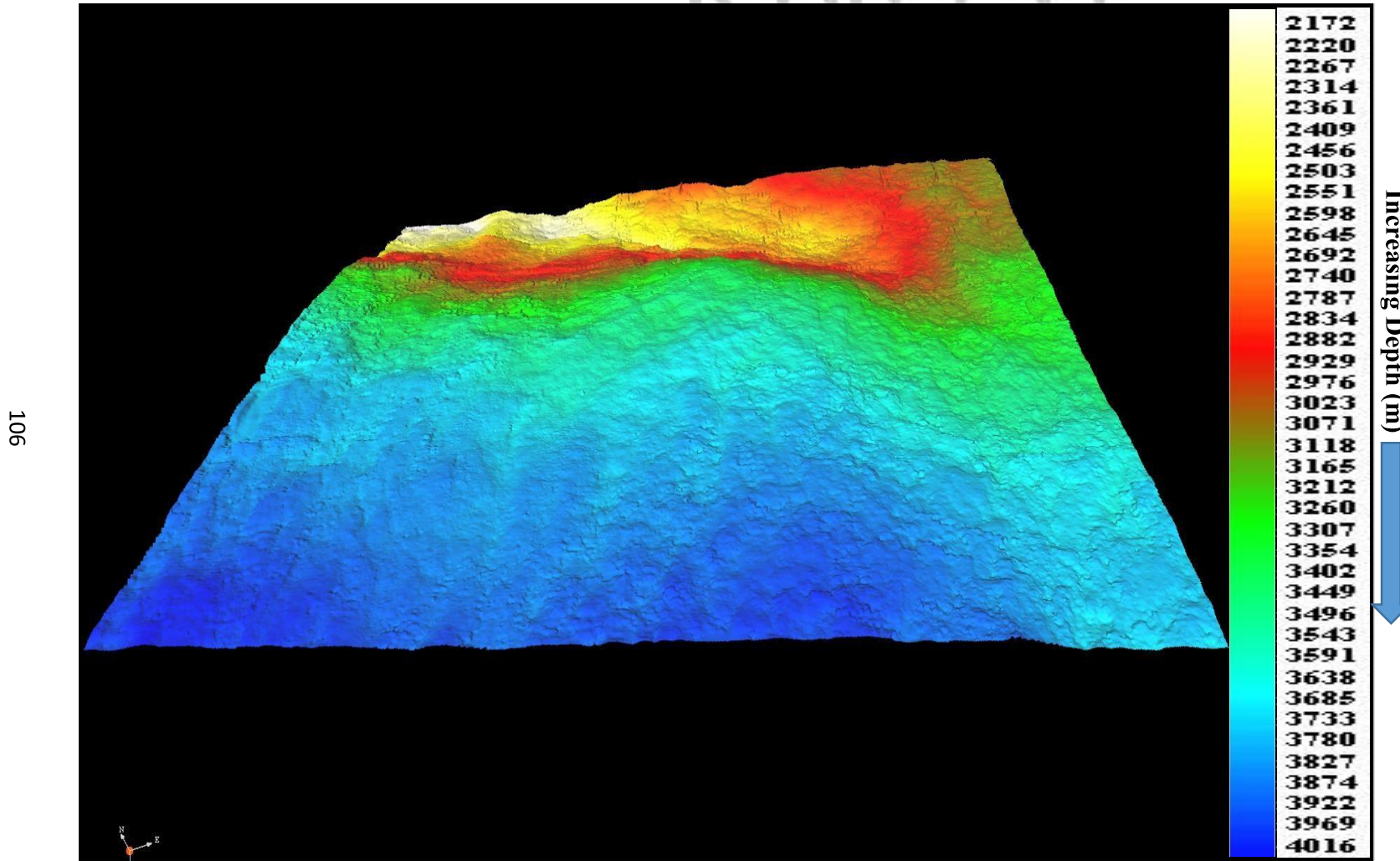
Although there is no apparent roll over anticline or syncline, a few three-way and four-way closures (Y and Z respectively) can be identified on the map.

4.2.3.2 Structure Map

KNILIST

Figure 4.10 3D structure map of Middle Shale

With the exception of the depth range varying from 2172 m to 4016 m, there is not much difference between this structure and the structure of Figures 4.8.



4.2.4 Base of Reservoir

4.2.4.1 Contour Map

C.I 40



4.2.4.1 Contour Map

C.I 40

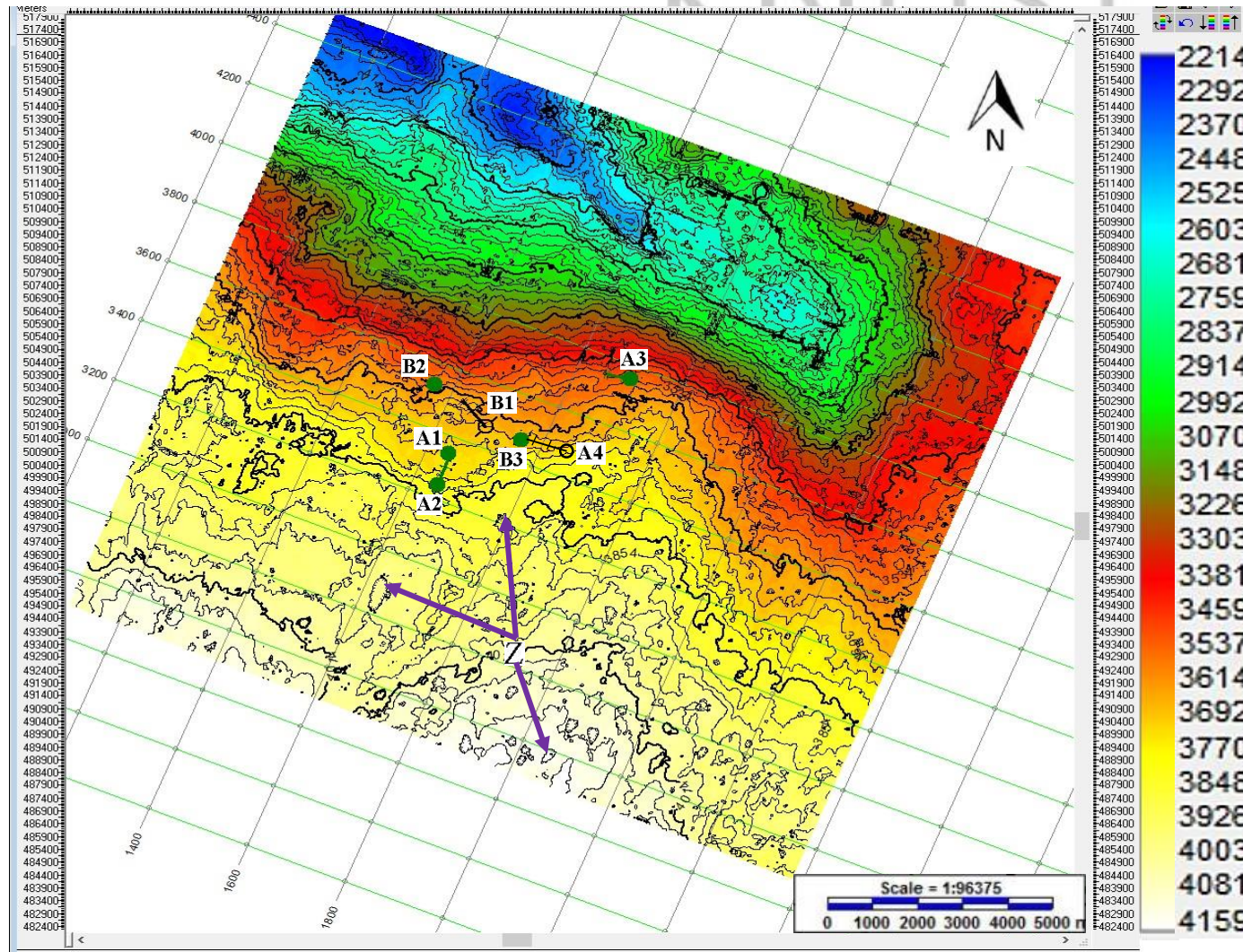


Figure 4.11 Contour map of Base of Reservoir

On this map, a large number of four way closures (Z) are evident. Depth variation ranges from 2214 m to 4159 m and the general trend of depth variation is present here too. The relatively lower depth range starting from 2214 m as opposed to the two previous horizons confirms this.

Increasing Depth (m) ↓

4.2.4.2 Structure Map

4.2.4.2 Structure Map

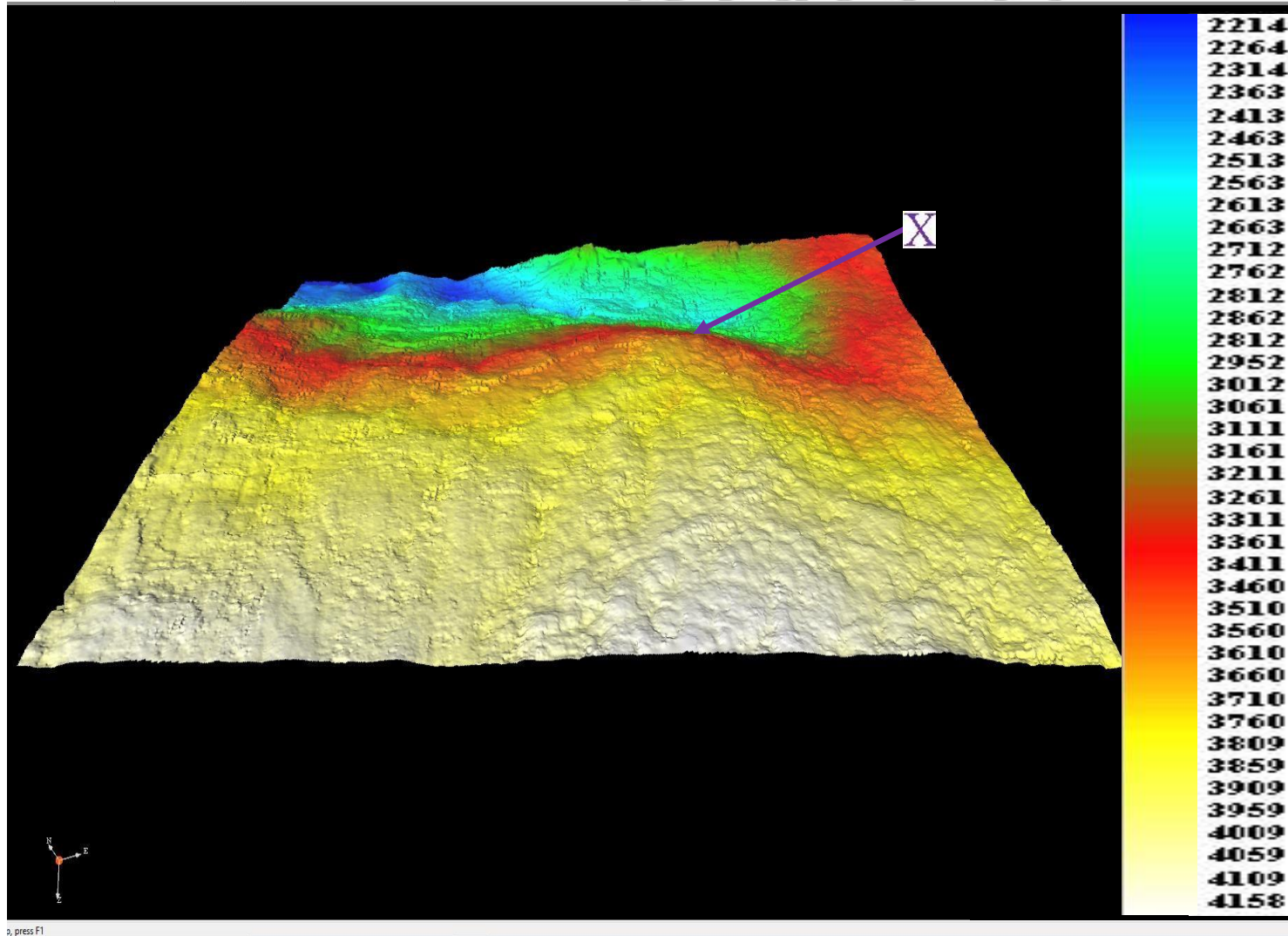


Figure 4.12 3D structure map of Base of Reservoir

There is no significant difference between this structure and that of Figures 4.8 and 4.10, with the exception of the variation in layout, and the shallow structural elevation at the top of the map which appears to be much deeper - with the shallowest point occurring at 2214 m in this figure as opposed to 2159 and 2172 m in Figure 4.8 and 4.10 respectively.

4.3. HORIZON AMPLITUDE MAPS

4.3.1 Top Upper Reservoir

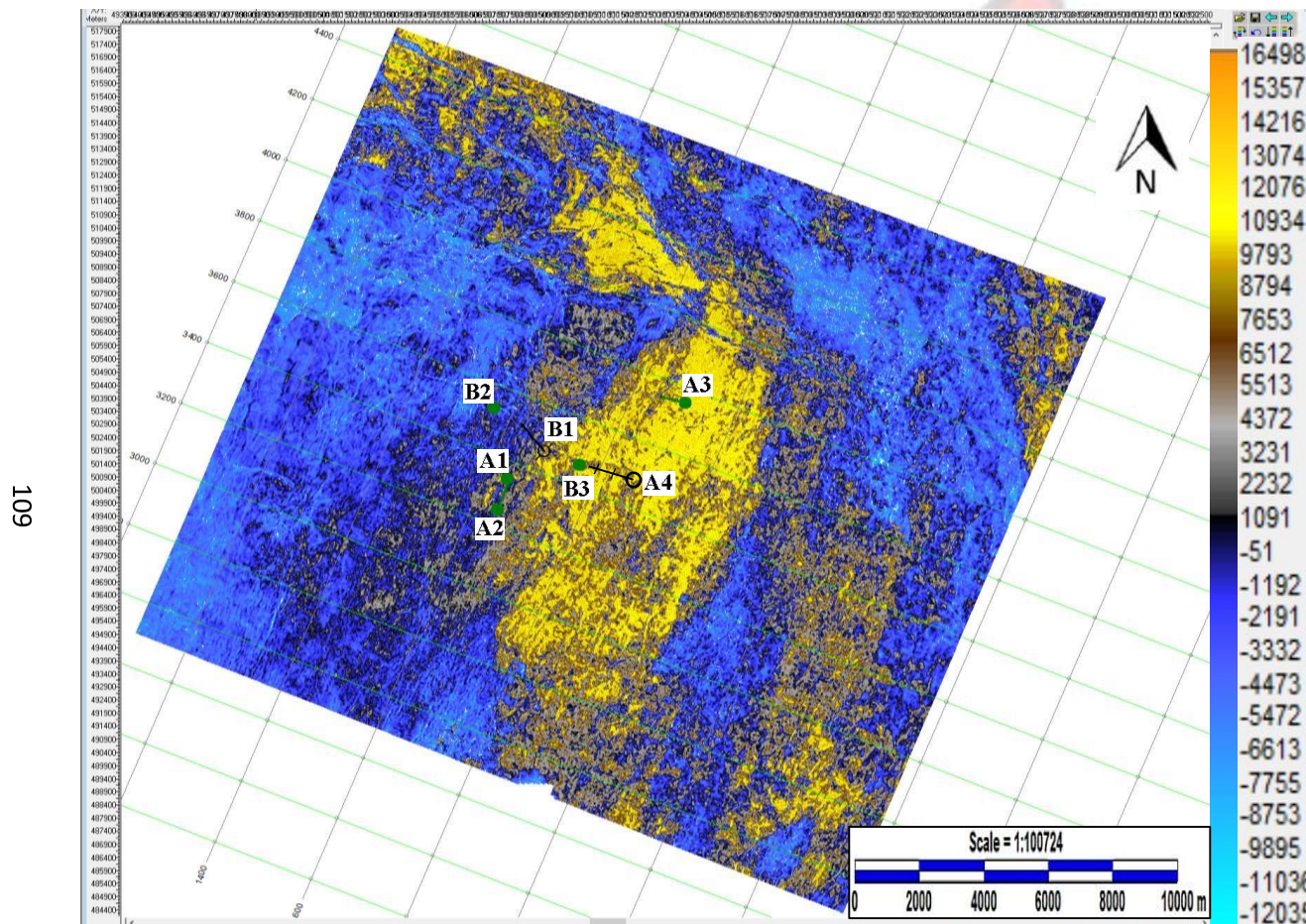


Figure 4.13 Amplitude Response of Top Upper Reservoir

The bright yellow reflections are indicative of sands due to the high energy amplitudes measured at those locations. The shape of the sand response and the structurally dipping characteristics of the horizon in the down -dip direction gives the indication that the sediments might have originated from the top left quadrant of the map (in the north west direction) and were very gradually transported downwards (seen from the shallow gradient of sand descent). The sudden deviation of sediment migration into the north south direction suggests the presence of a structure which hindered the original path flow. This assumption is confirmed by the high elevations identified in that area on Figure 4.12. This structure is popularly called the Tano Basin, and runs through all the horizons. There is no evidence of channels, suggesting the deposition could be in the form of a fan.

4.3.2 Middle Shale

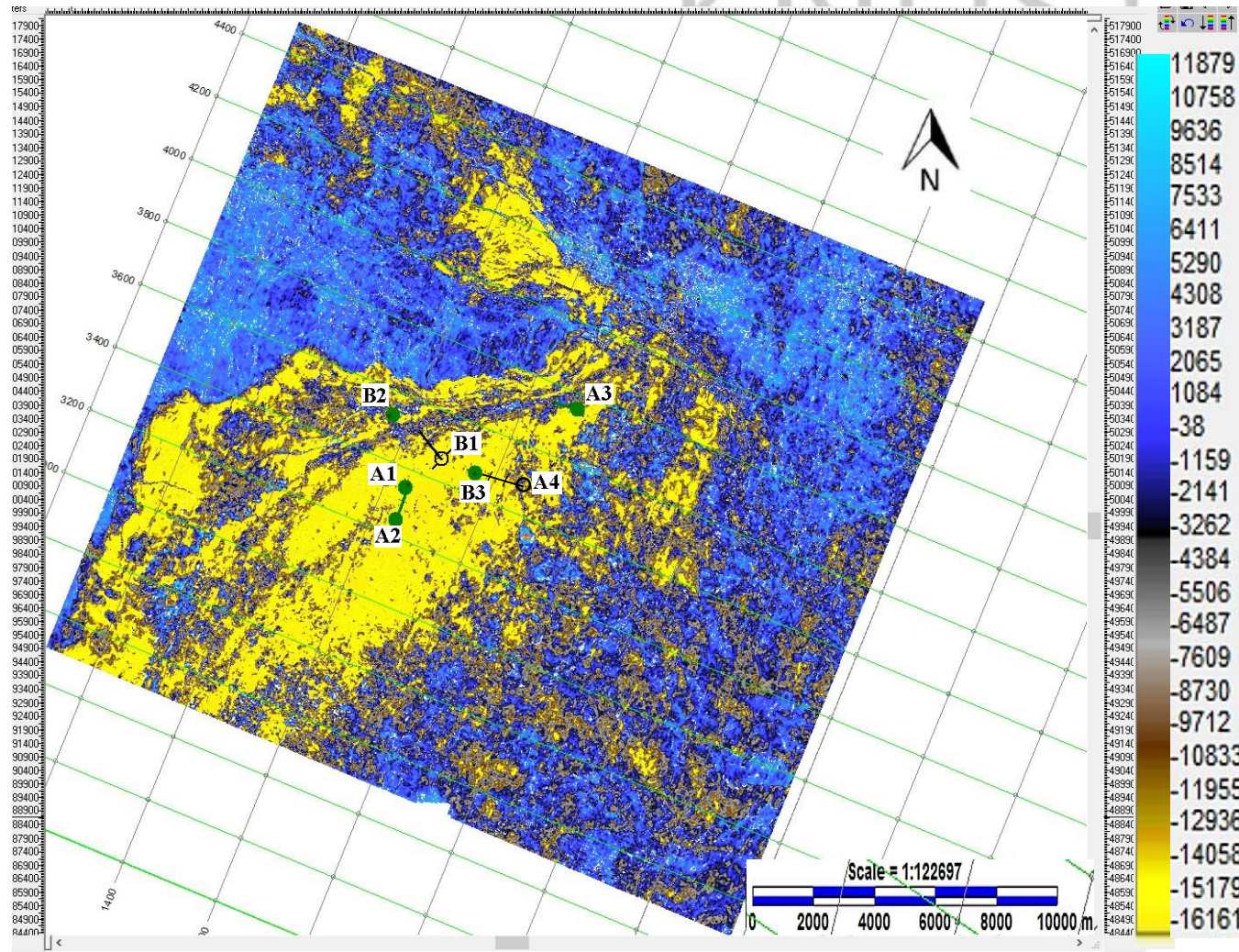


Figure 4.14 Amplitude response of Middle Shale

Here, the bright yellow reflections are rather indicative of shales, due to the low amplitude energies recorded at those locations. The shales appear to follow the same migration path from the onset, but after being deviated by the Tano nose, spread out in the form of a large fan with the majority of the shales being deposited in the lower left quadrant of the map where the structure is deepest. The shale migration after the Tano nose deviation is therefore in the down-dip, south-western direction. The magnitude of shale deposition in this horizon indicates that the shales serve as reservoir seals to the sand formations below. The sealing shales therefore act as surface unconformities and help in the delineation between the upper and lower reservoir formations.

4.3.3 Base of Reservoir

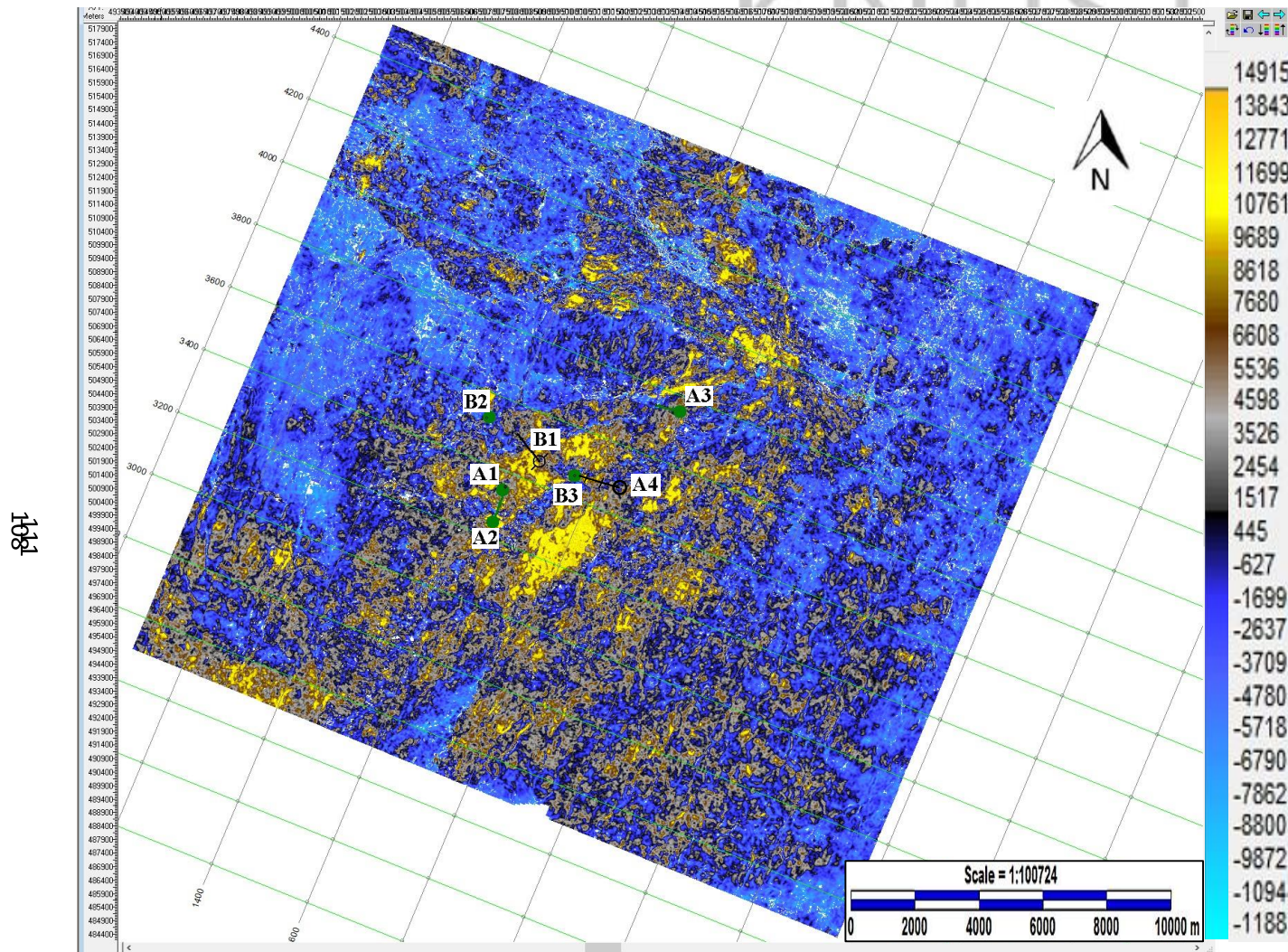


Figure 4.15 Amplitude response of the Base of the Reservoir

The bright yellow reflections are indicative of sands. This horizon shows small sand pockets scattered haphazardly over the central and base of the survey area. Only one relatively continuous body is identifiable on the right side of well A2. An outline resembling the middle shale amplitude map is suggestive of the fact that the sands may have followed the same depositional path. It is important to note that this map might not be a true reflection of the subsurface, as the horizon was not picked along the exact location of the base, but rather as closely as possible to it, to maintain a certain level of reflection continuity.

4.4 FAULT INTERPRETATION

4.4.1 Top Upper Reservoir

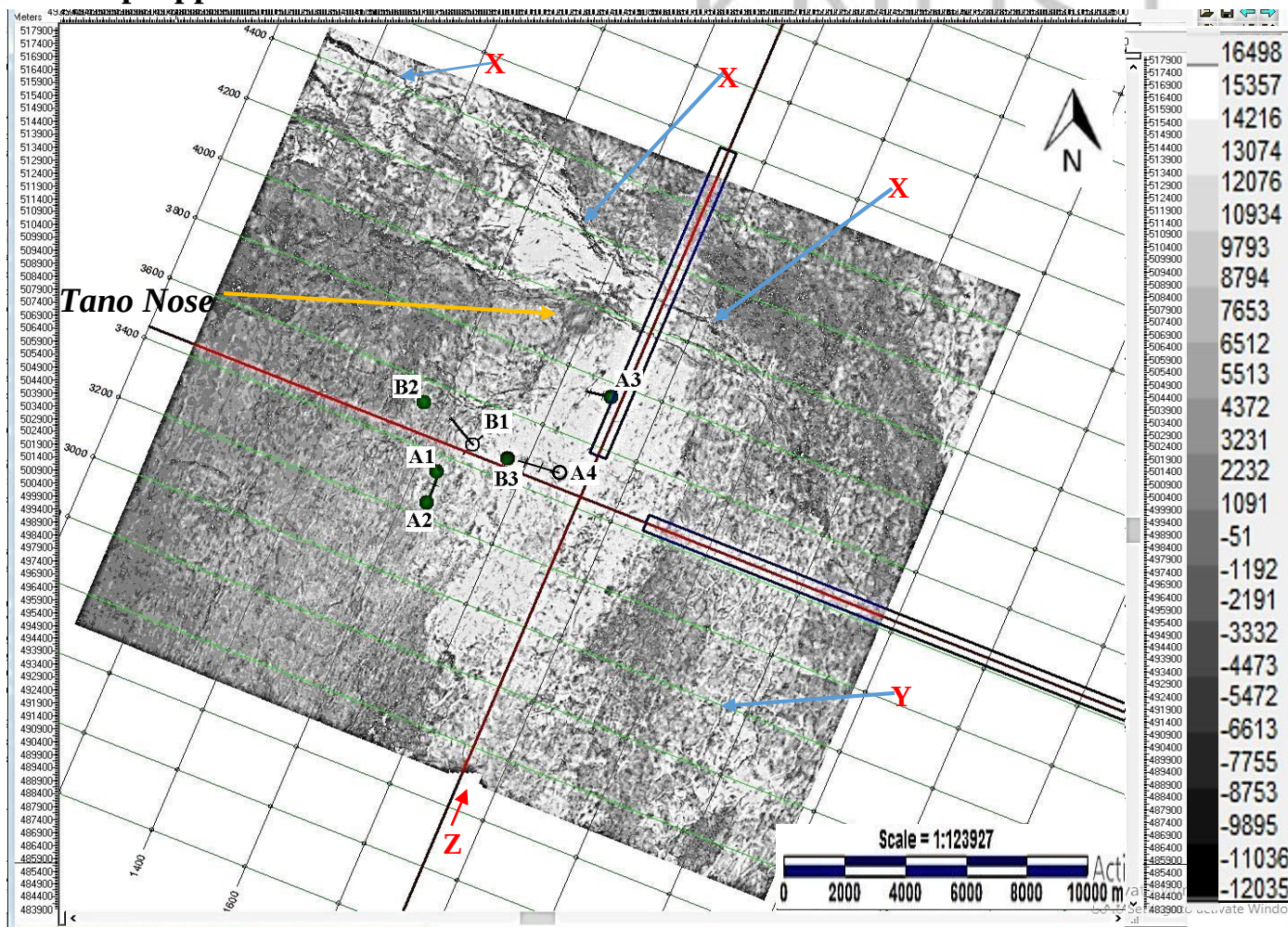


Figure 4.16 Amplitude anomalies (Faults) on Top Upper Reservoir

From the map aside, 3 main types of faults can be identified on the amplitude map surface. Fractures (X) running horizontally through the upper part of the survey area, a fracture swarm (Y) which would be more clearly seen with the aid of a coherency map, and a triangular blank section at the extreme base of the map (Z). The Triangular portion is simply as a result of the missing or blanked out data on the seismic sections of the first ten crosslines and their corresponding inlines in that region. This could have occurred from equipment failure or simply if the equipment was not being able to pick the seismic reflections for one reason or another at that point. The Tano nose is clearly depicted on this map and the other two.

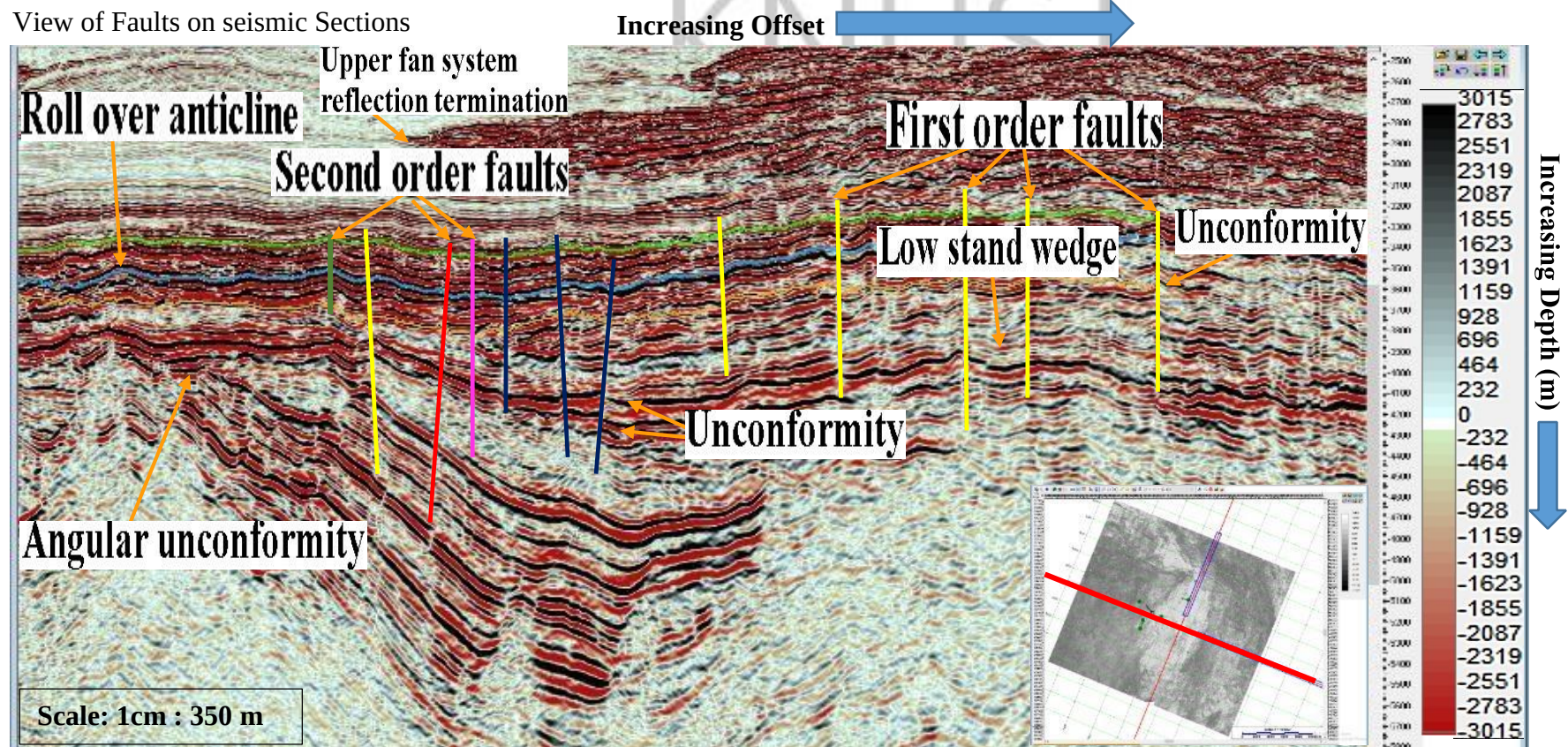


Figure 4.17 Faults on crossline

There is fault compartmentalization in the reservoir. The first-order faults still displace strata in the Albian formation below, but most second-order faults have terminated at shallower depths and no longer cause reservoir compartmentalization. Several roll over faults are present on the cross section. An example is the roll over anticline at the extreme left hand corner of the section. Angular unconformity and fault-induced normal unconformities are also evident on the section, as well as low stand wedges in the layer just below the reservoir base. In addition, fan systems (which are not faults) are present above the reservoir. The reflection termination is outlined on the section.

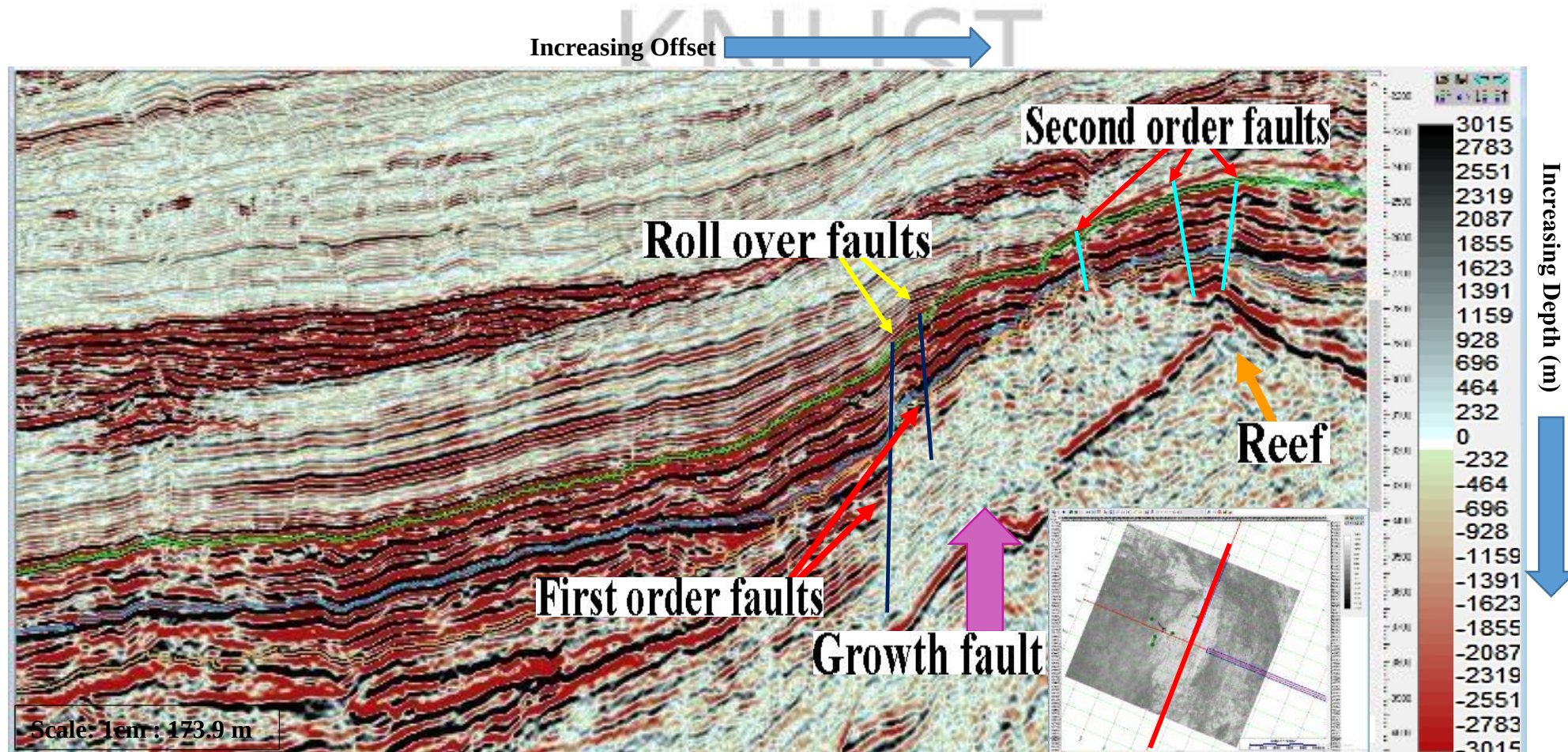
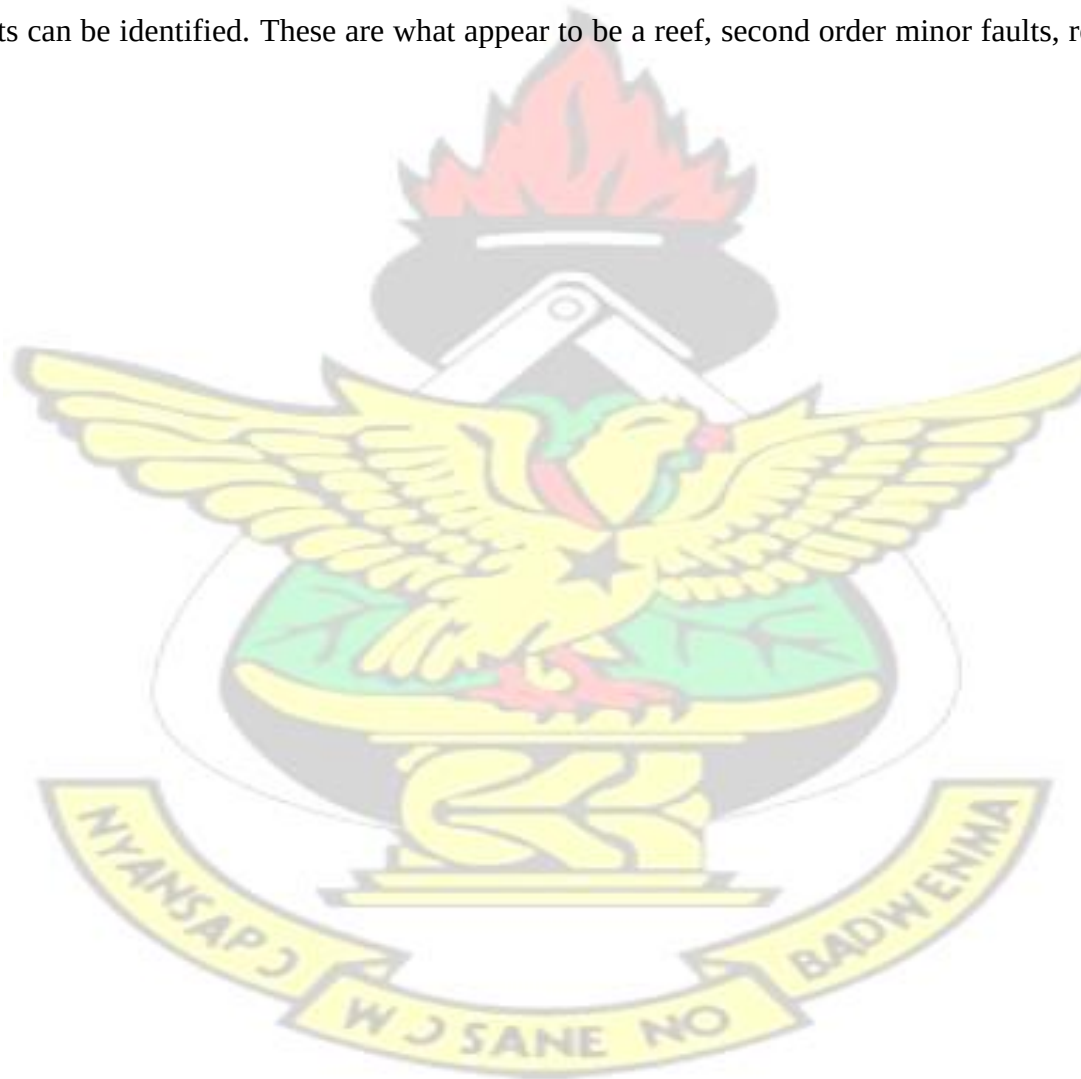


Figure 4.18 Faults on inline

KNUST

On this inline only a few faults can be identified. These are what appear to be a reef, second order minor faults, roll over faults and a growth fault possibly as a result of folding.



4.4.2 Middle Shale

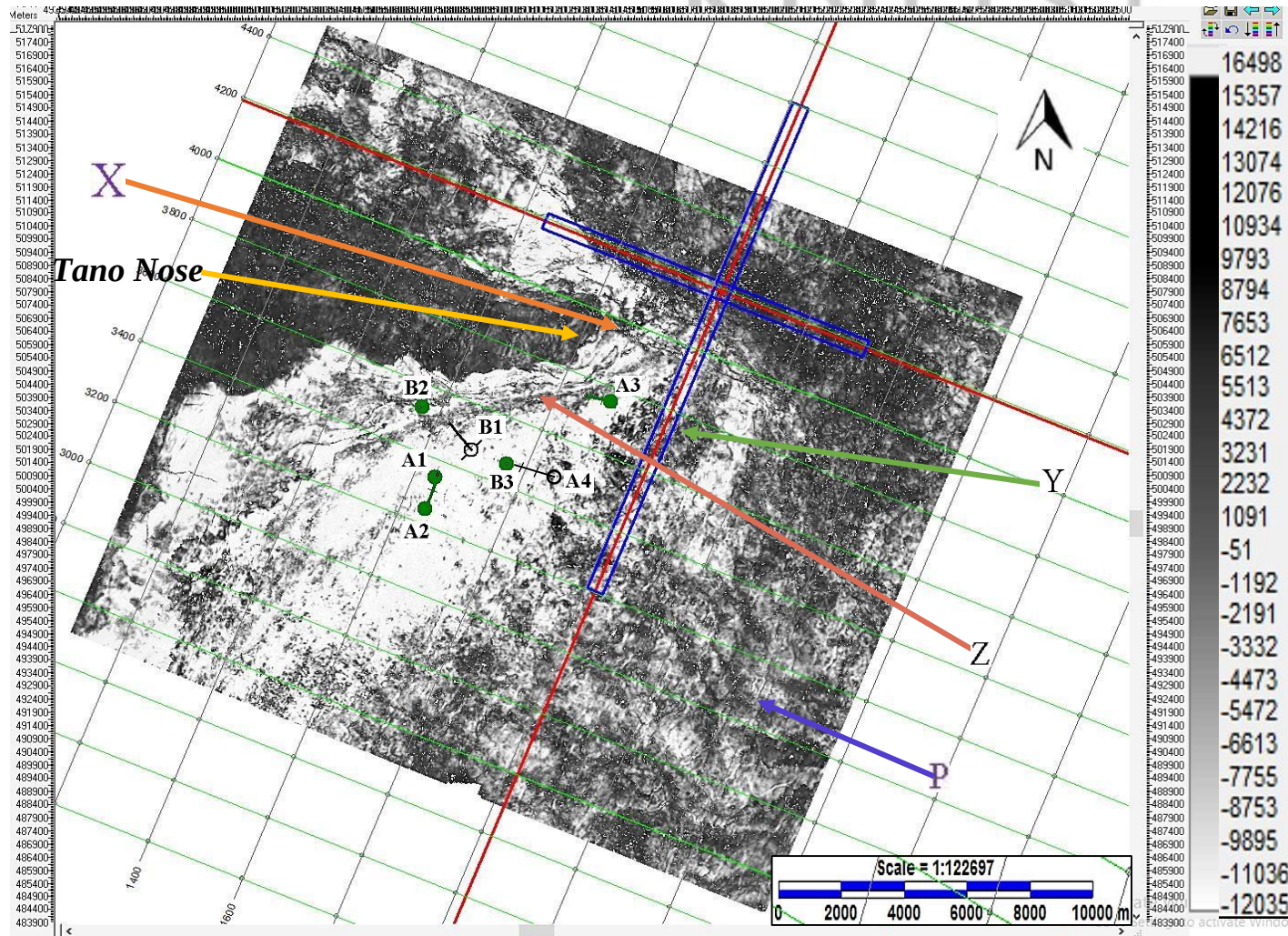


Figure 4.19 Amplitude anomalies on middle shale

On the surface of the map, a few faults can be identified. Again, the shape of the Tano Nose (X) is clearly visible here. From a glance at the colour bar it seems that this structure is not constituted of sand and its amplitude which is much higher than that of shale indicates that it is not entirely made up of shales either. It could therefore possibly be a hybrid of both, intermixed with other sediment types. At (Y), there seems to be an abrupt increase in amplitude as compared to the shale amplitudes. This could be indicative of the presence of another structure, or attributed to folding, uplift and erosion of the formation at that location. (Z) indicates another unconformity in the structure which may be caused by a channel-induced erosion. In addition, an up-close look at (P) reveals a series of vertical faults.

View of Faults on seismic sections

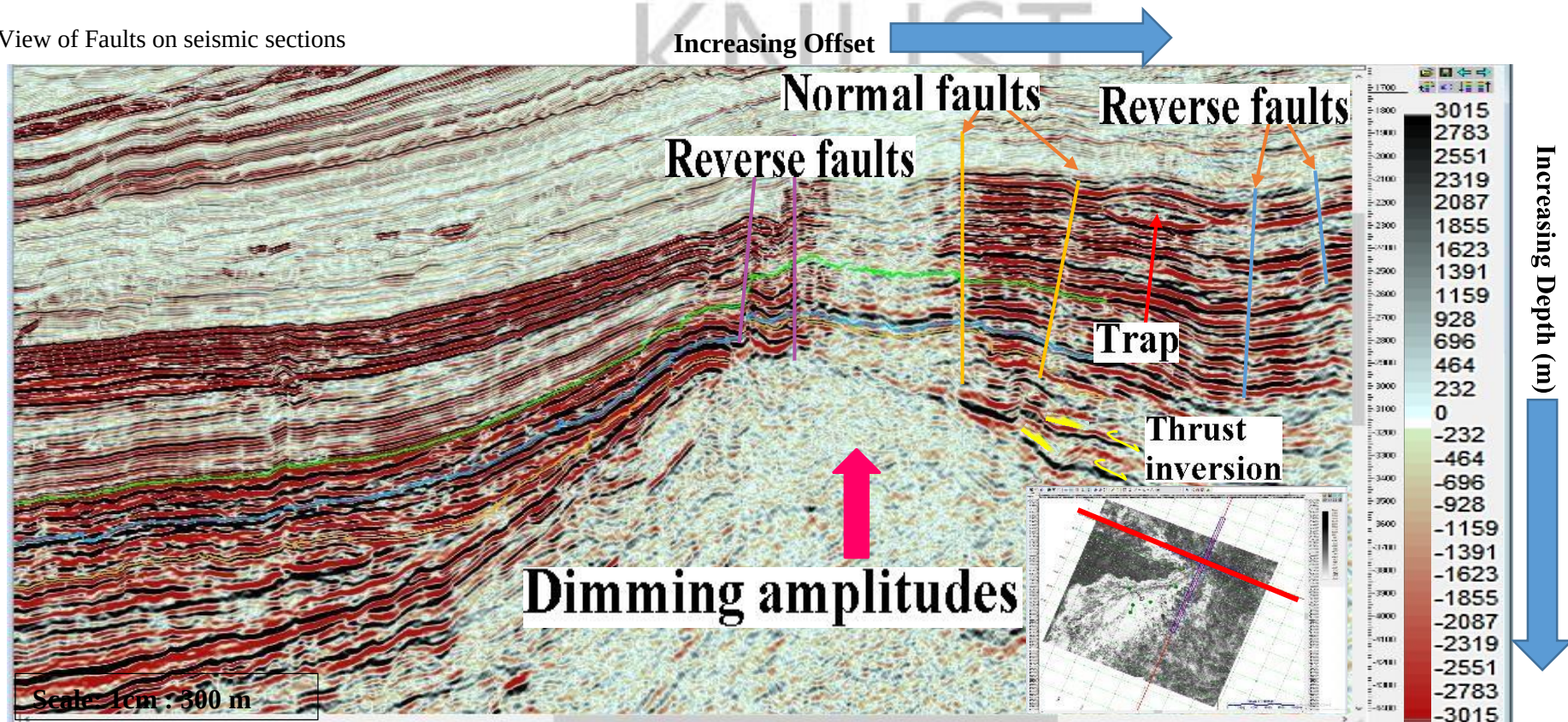


Figure 4.20 Fault on inline

One major fault, a few normal faults and reverse faults can be seen on this seismic section. In addition to that, dimming amplitudes are present as a result of an uplift of basement material (rock) that tends to either disperse/absorb the seismic energy as it travels down the subsurface. Thus, none of the seismic energy is reflected back to illuminate the overlying strata. Normal and reverse unconformities are also present. Thrust inversion is also seen in the lower formation beneath the reservoir.

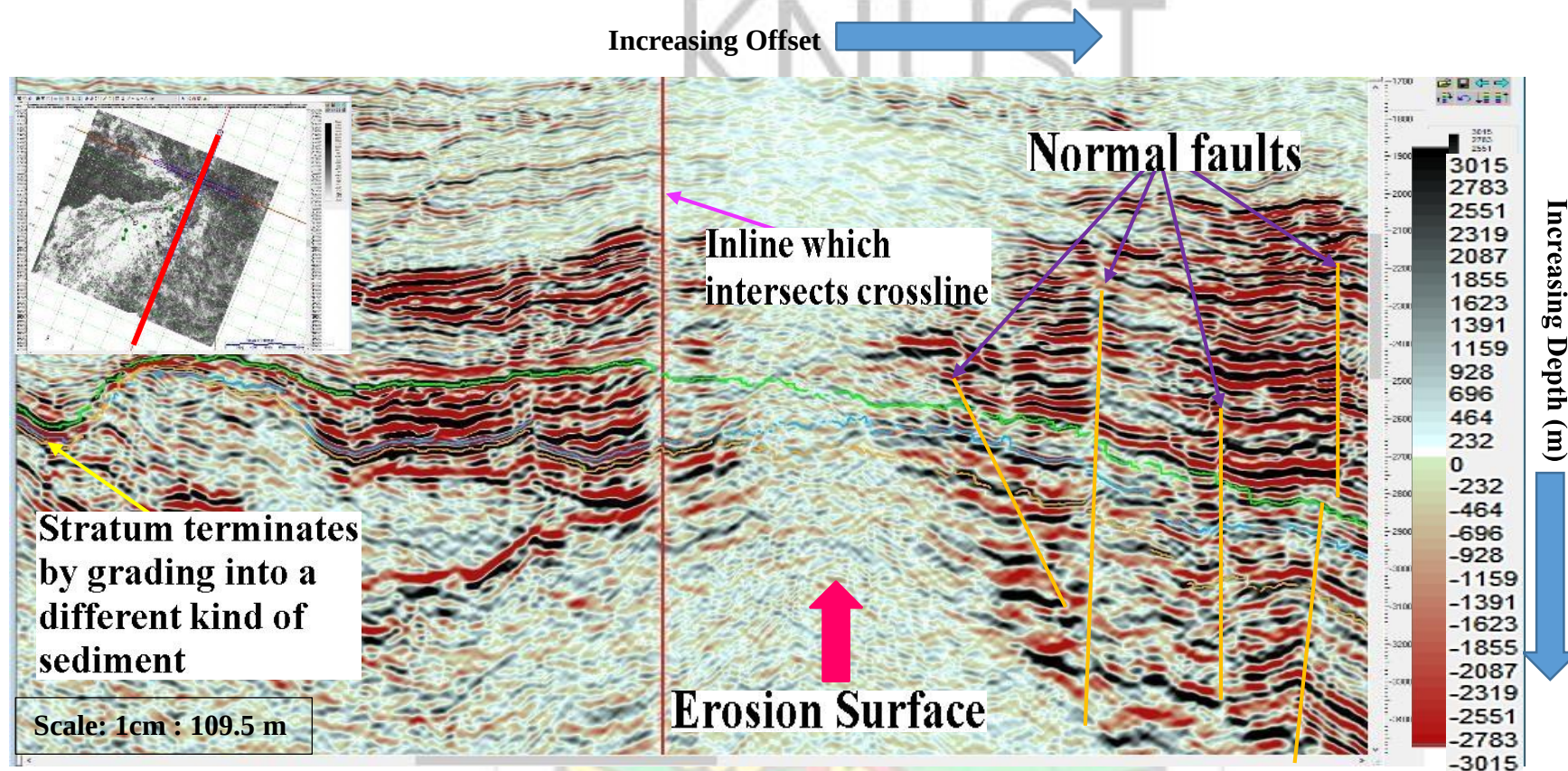


Figure 4.21 Fault on crossline

The facies offset presence on this seismic section is a possible indication of an erosion surface which could be attributed to the occurrence of an abrupt decrease in water depth. This erosion surface was widespread across several inlines and therefore resulted in the truncation of older strata. Also present are first order faults which cut through the entire reservoir, resulting in unconformity surfaces. In addition, unconformity-causing normal faults can be identified on this seismic section.

4.4.3 Base of Reservoir

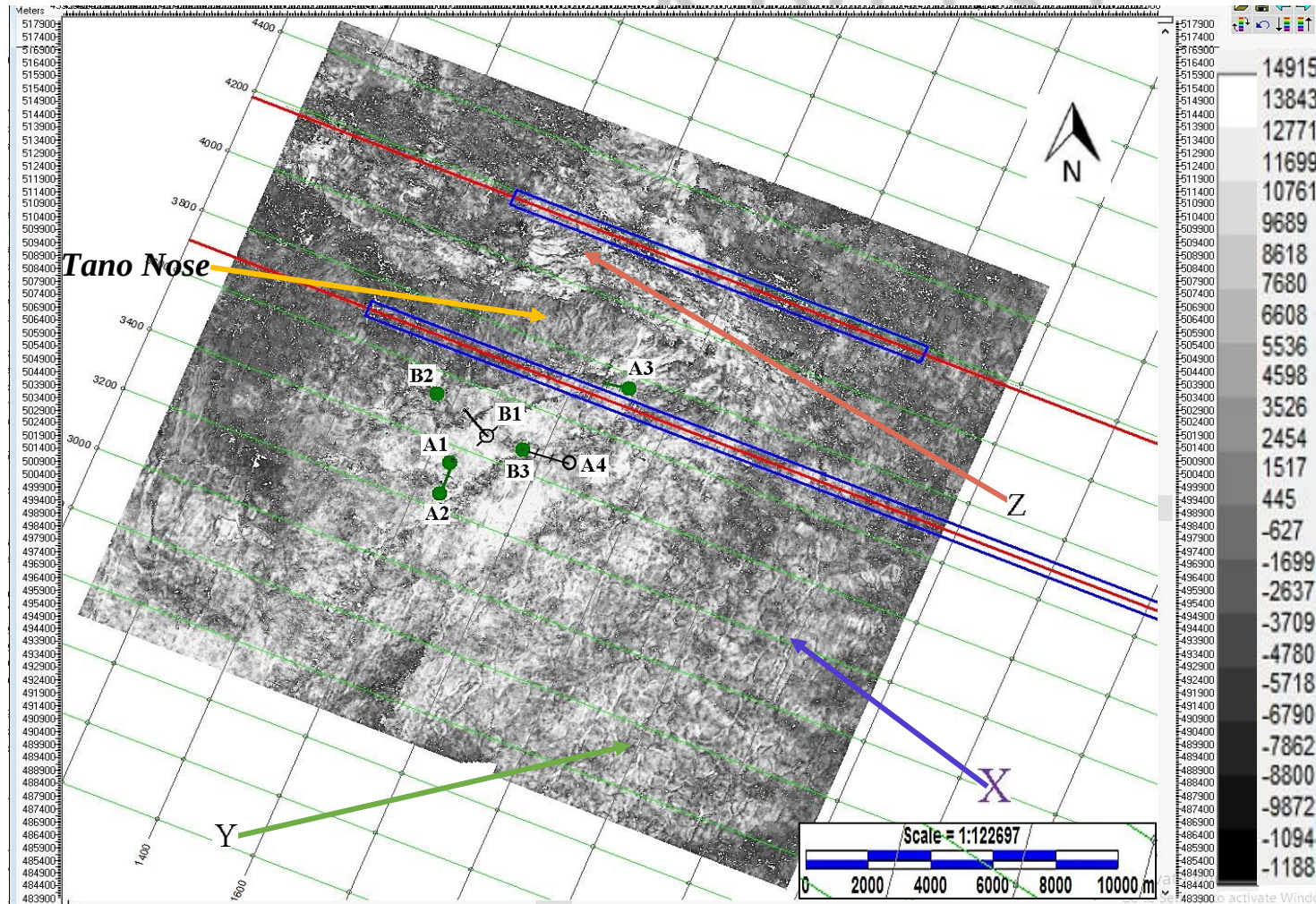


Figure 4.22 Amplitude anomalies on Base of Reservoir

An up- close look at the base of the map reveals, a series of vertical faults (X), in addition to fracture swarms (Y). The Tano nose is also evident here too. Faults identical to the one at the top of the Middle Shale map are also present here (Z).

View of Faults on Seismic Sections

Increasing Offset →

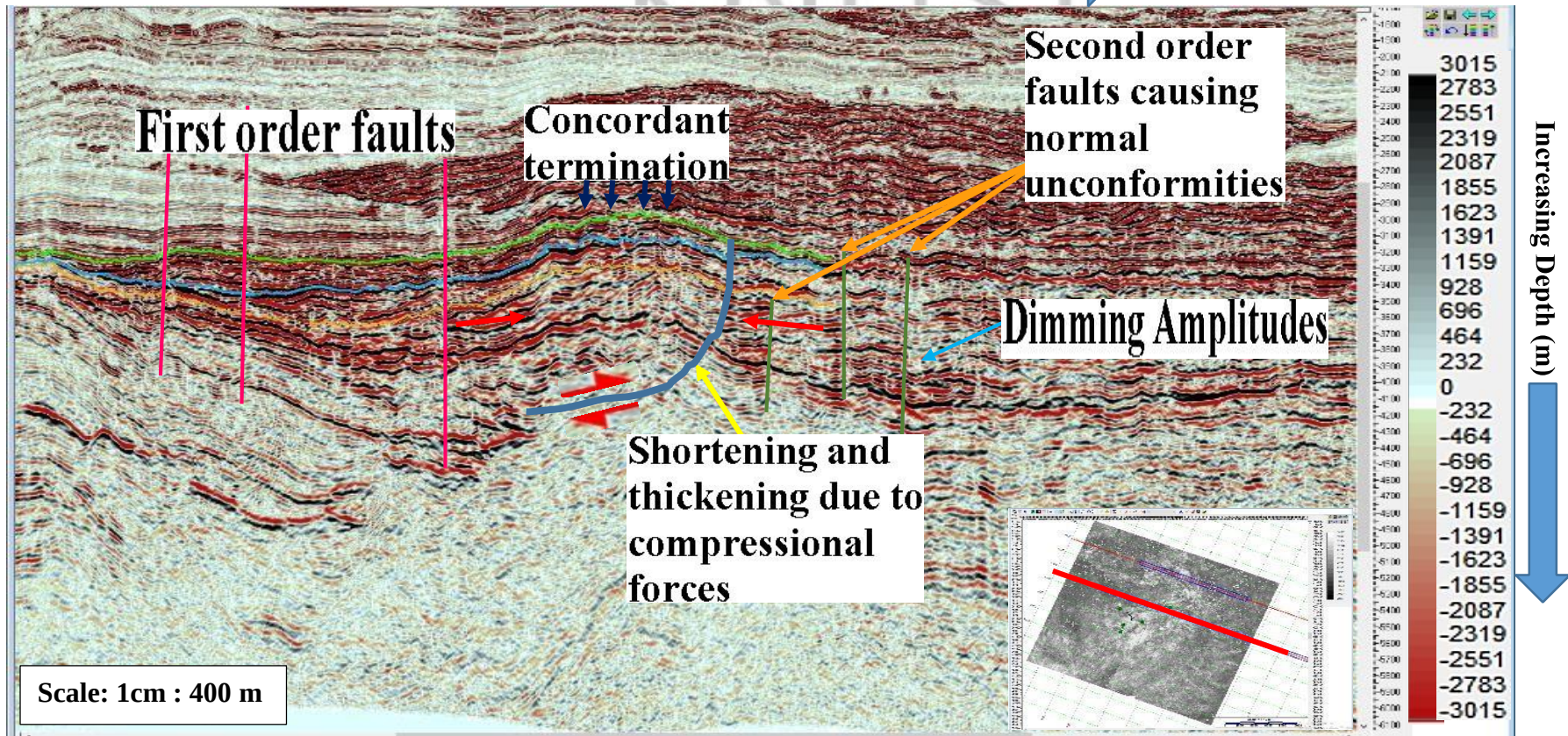


Figure 4.23 Faults on crossline 1

Present on this seismic section are first order faults, normal unconformities caused by minor second order faults and shortening and thickening of bed which are possibly due to compressional tectonic forces and or shelf plate motion.

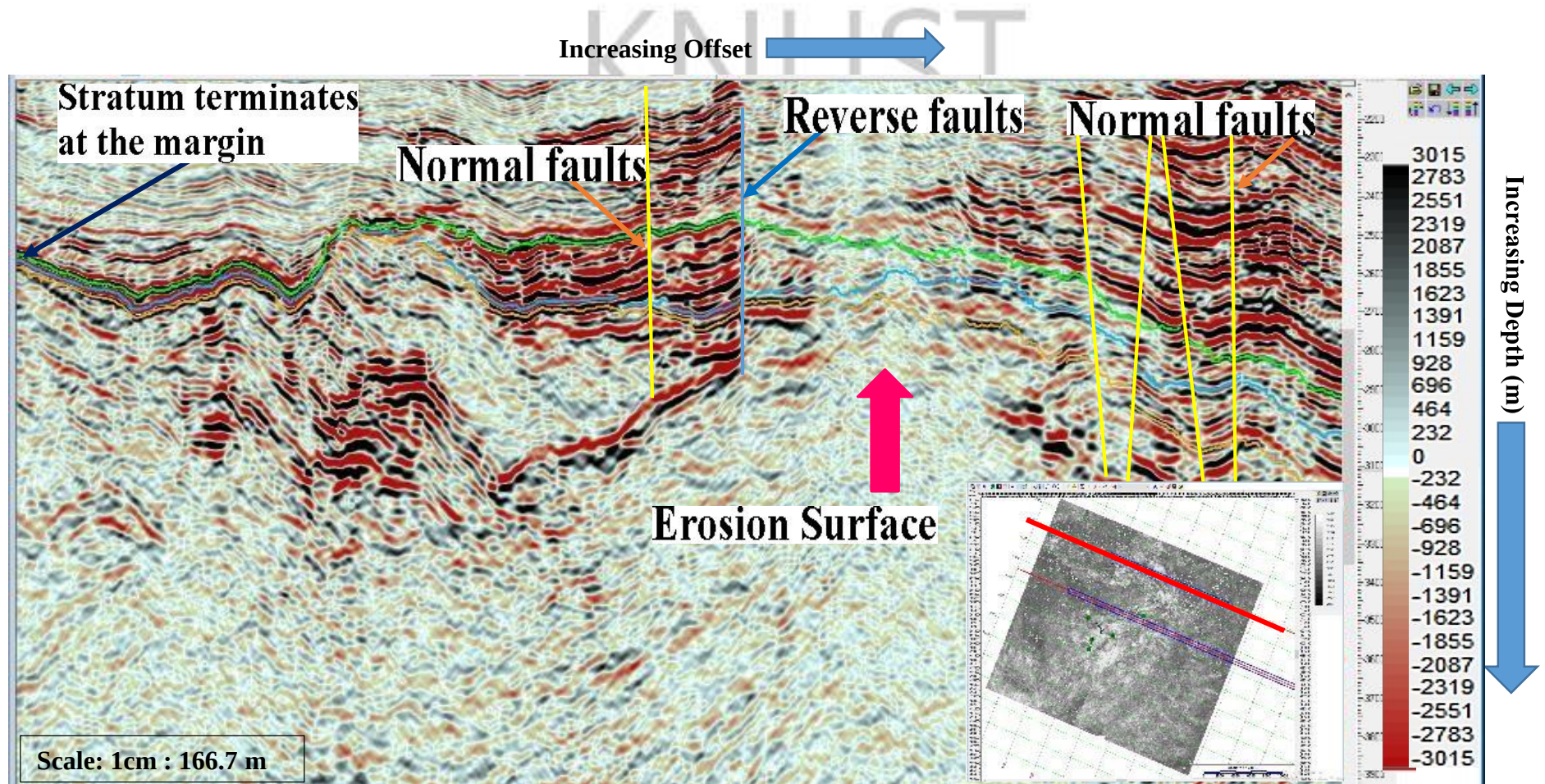


Figure 4.24 Faults on crossline 2

Two types of faults are seen on this section. On the left side of the eroded surface, reverse faults are seen and on the right side, normal faults are present. The center represents an eroded surface possibly due to the occurrence of an abrupt decrease in water depth.

VOLUMETRICS

4.5.1 Top Upper Reservoir and Middle shale

4.5.1.1 Vatmin

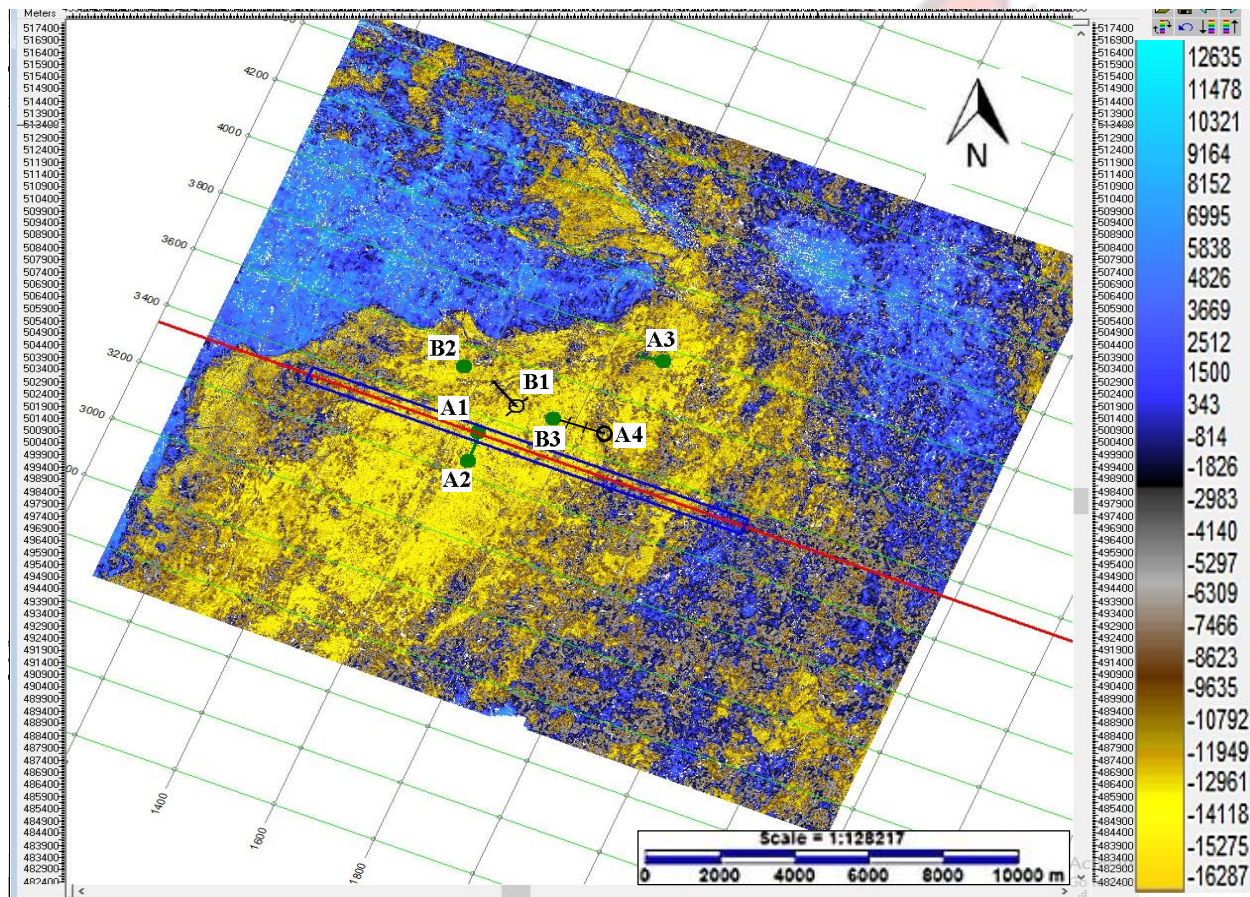


Figure 4.25 Map of vatmin extraction between Top Upper Reservoir and Middle Shale

This map is a reflection of the extraction of the most minimum amplitude responses of the sands, and since it has been determined that in this reservoir the positive amplitudes (peaks) are indicative of the sands and the negative amplitudes of the shale, the maps displaying higher amplitudes become a focal point of interest. It is evident at first glance that the sand deposition pattern looks very similar to the Middle shale horizon distribution pattern. This map is therefore not suitable for the interval map extractions.

Vatmin crossline

Increasing Offset



Increasing Depth (m)

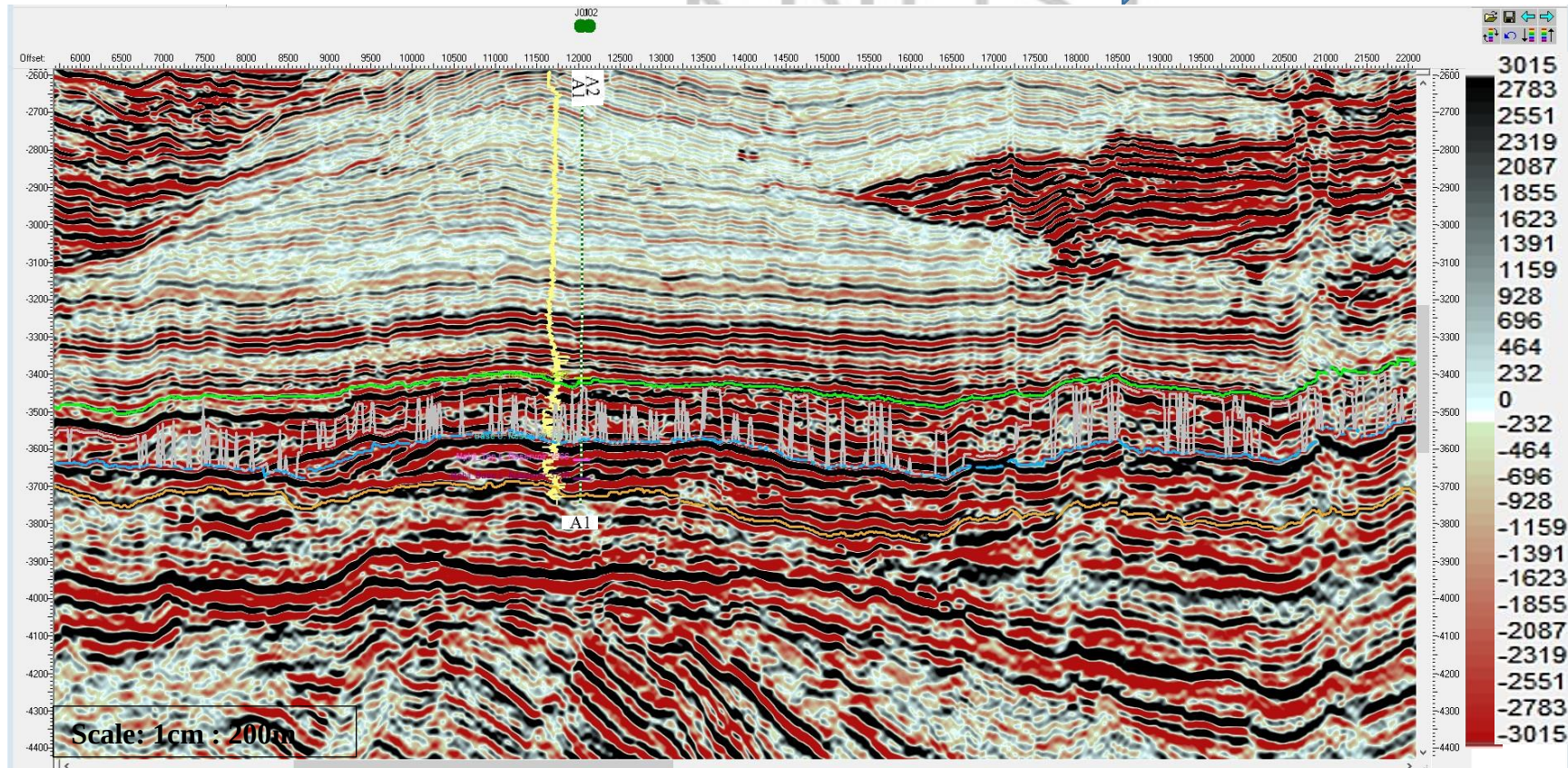


Figure 4.26 Crossline showing the behaviour of the vatmin attribute- the minimum amplitude responses are picked along the troughs

The grey line in Figure 4.26 shows the minimum amplitude points that are selected by the vatmin attribute as it processes the reservoir data.

4.5.1.2 Vatmax

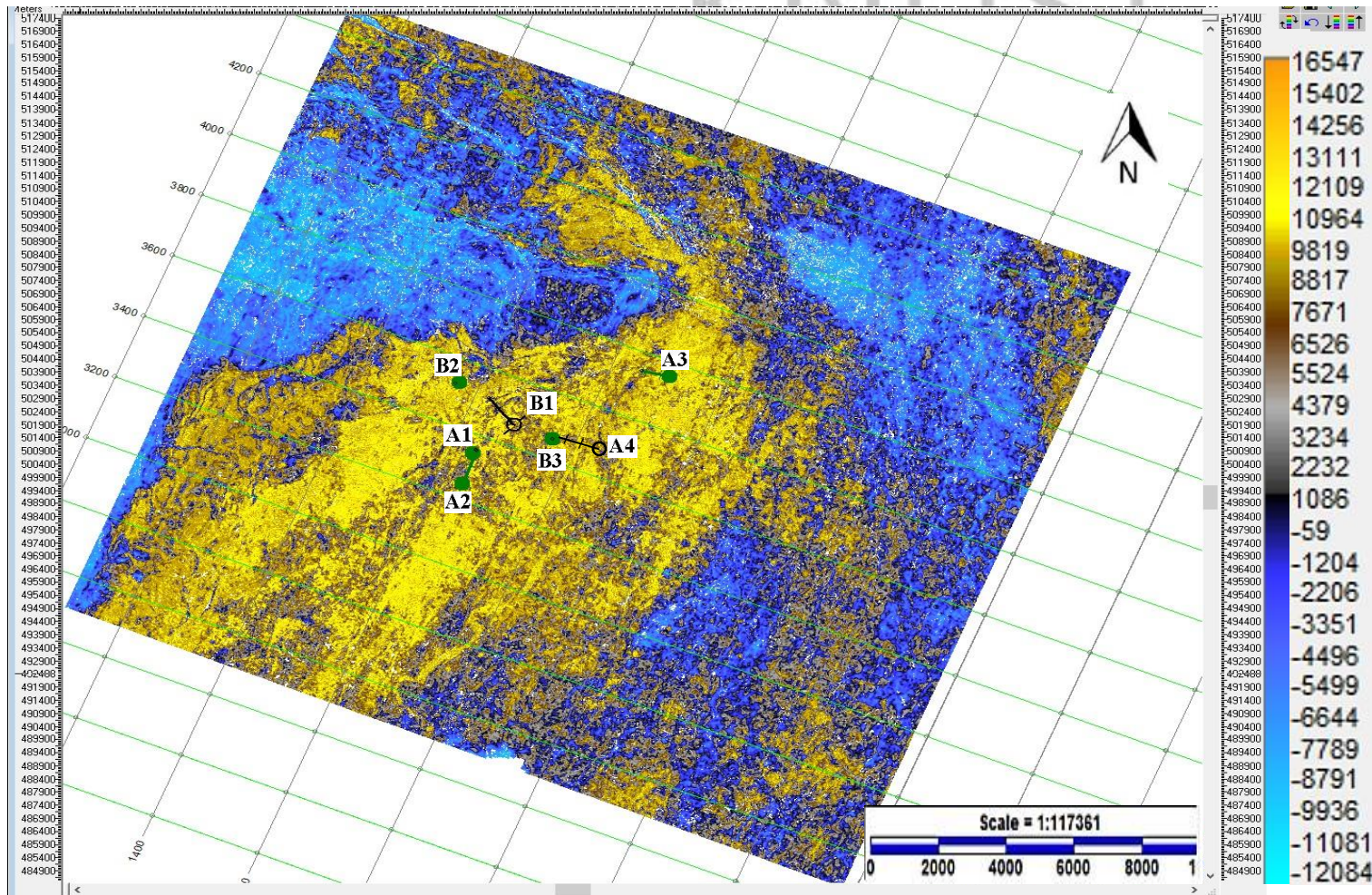


Figure 4.27 Map showing vatmax extraction between the Top Upper and Middle Shale

This attribute does the opposite of Figure 4.25 by picking the maximum amplitudes and mapping them. This however gives the impression that the sands are everywhere, which is known (from the log data) not to be true. This attribute map is therefore not an accurate representation of all the sands in the subsurface structure within the interval selected.

Vatmax Crossline

Increasing Offset

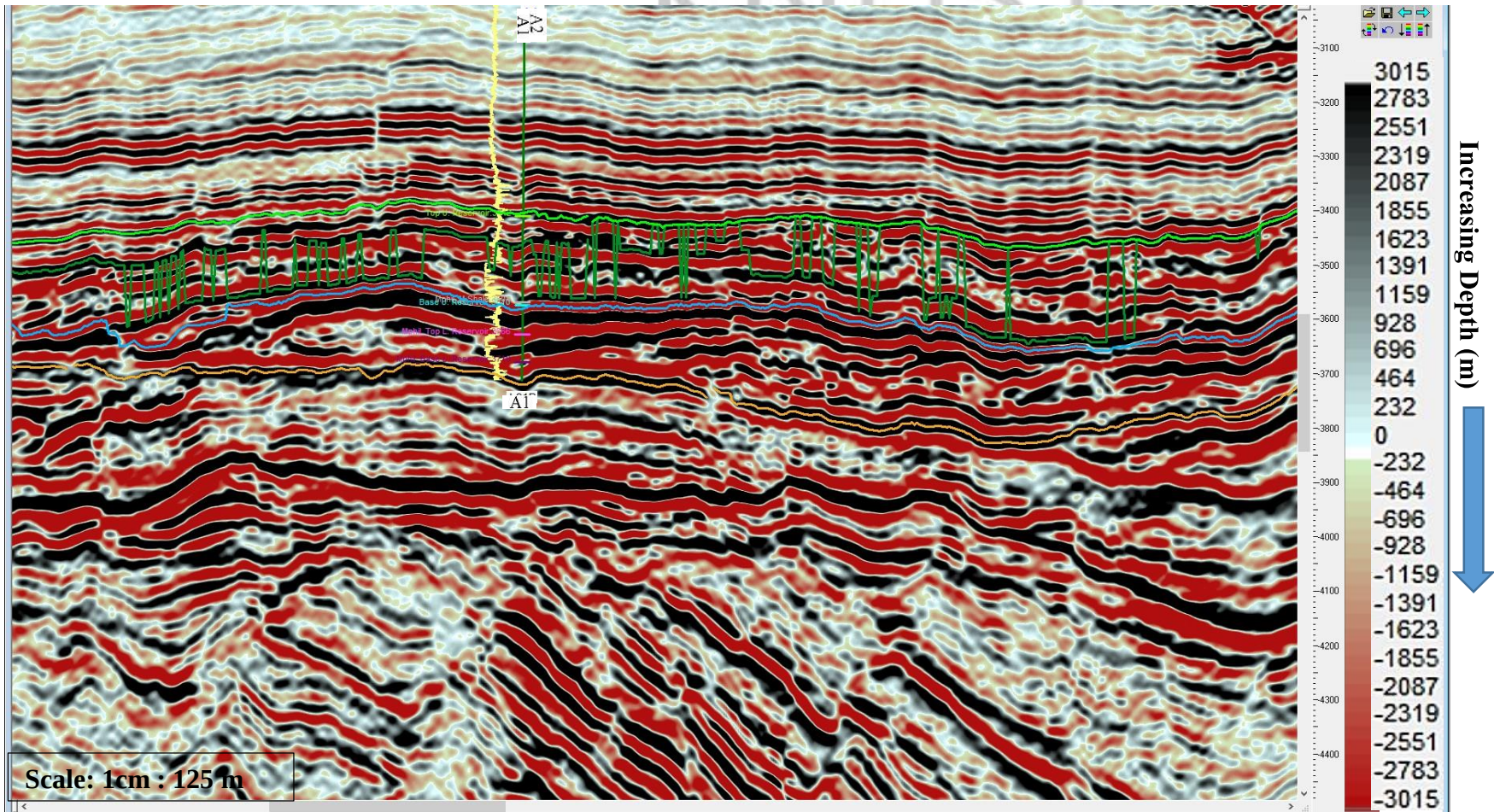


Figure 4.28 Crossline showing the behaviour of the vatmax attribute- the maximum amplitude responses are picked along the peaks. The green line in Figure 4.28 shows the maximum amplitude points that are selected by the vatmax attribute as it processes the reservoir data.

4.5.1.3 Vatrms

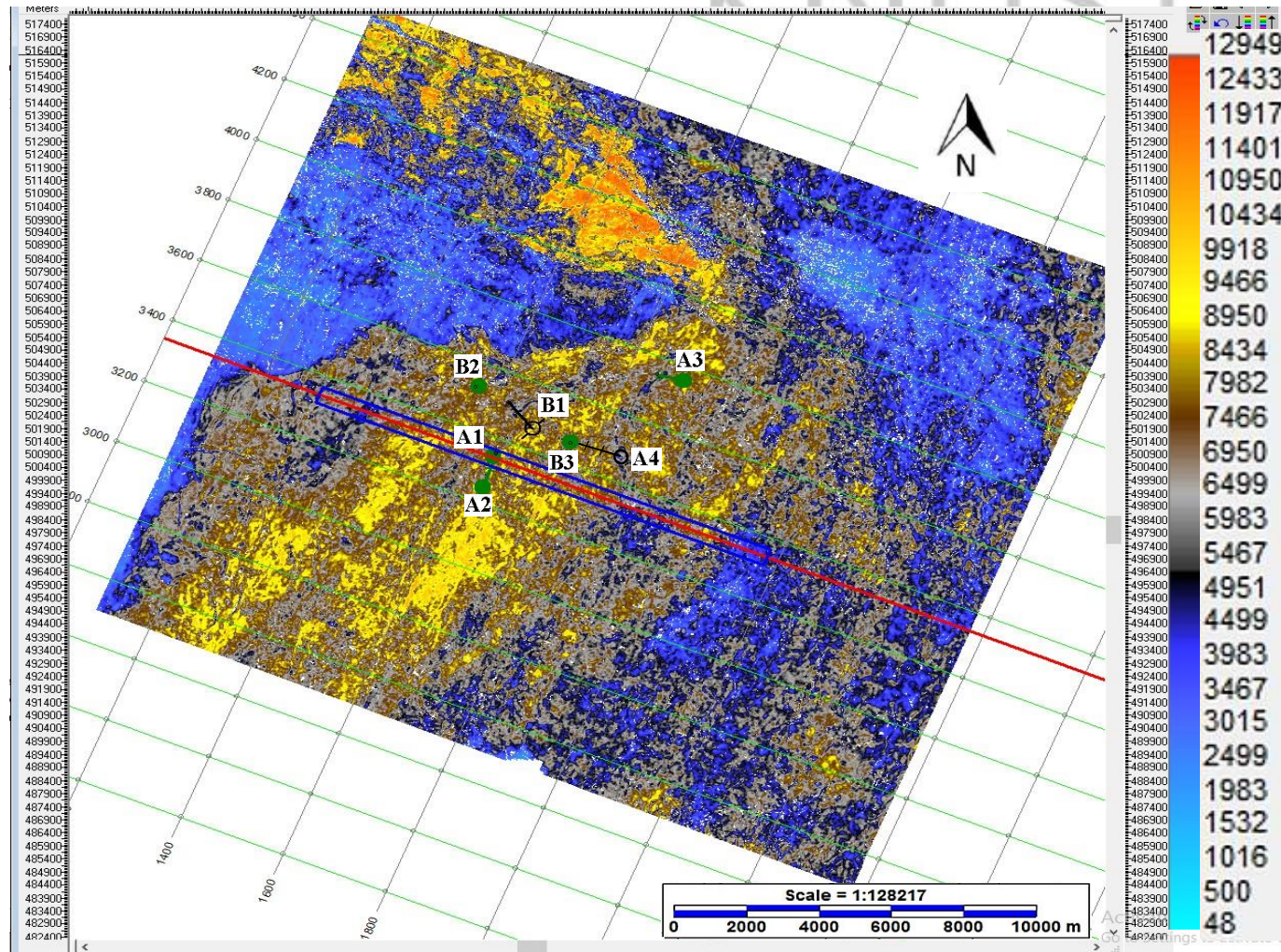


Figure 4.29 Map showing vatrms between Top Upper and Middle Shale

This attribute picks the RMS values. It seems to provide a more appropriate description of the sand distribution with the largest sand packages accumulating towards the base of the map, where depth values are greatest and favourable for accumulating the sands which are migrating south -westward in the down -dip direction. With the result from all the three attribute extractions, it was concluded that the vatrms attribute is the most appropriate for mapping the architectural elements (which show the extent of the reservoir and can be likened to the area of the reservoir) of the different intervals in the reservoir.

Vatrms crossline

Increasing Offset →

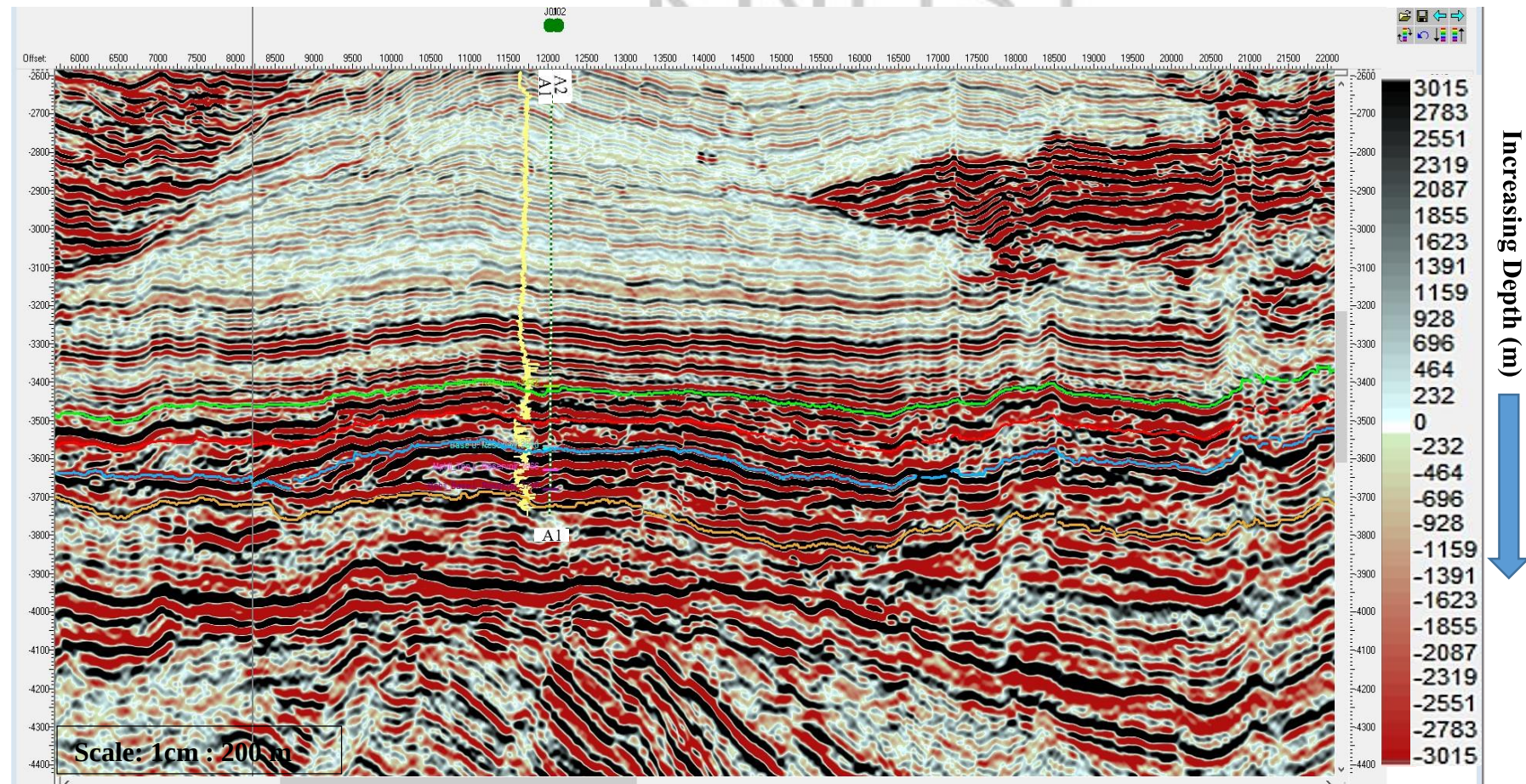


Figure 4.30 Crossline showing the behaviour of the vatrms attribute- the root mean square amplitude responses are picked

The red line in Figure 4.30 represents the result of the *vatrms* amplitude extraction.

Vatrms Nears and Fars for Top Upper Reservoir and Middle Shale interval

4.5.2.1 Vatrms nears

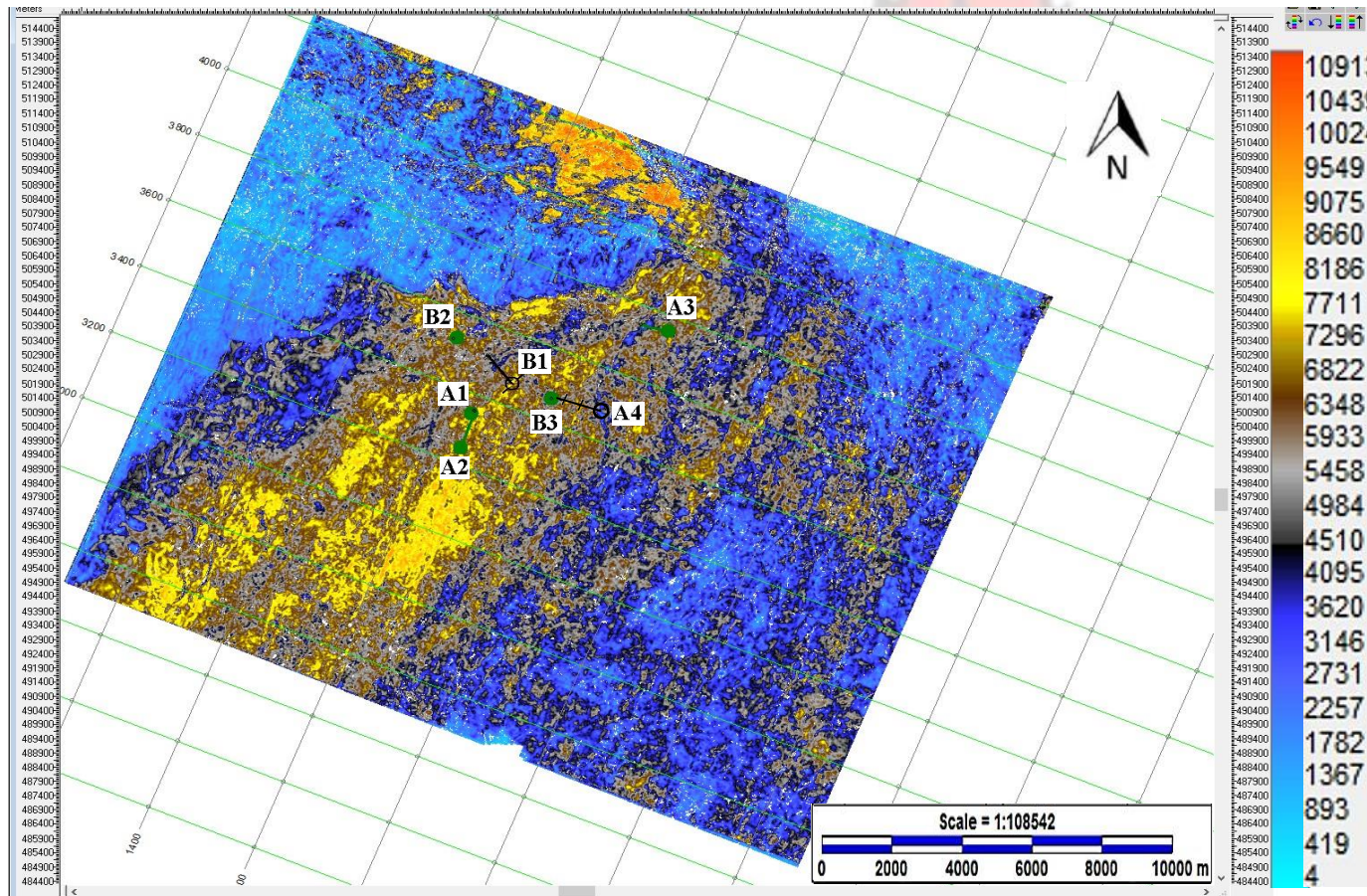


Figure 4.31 Map showing *vatrms* in the Nears

This calculation was extracted using the nears data.

4.5.2.2 Vatrms fars

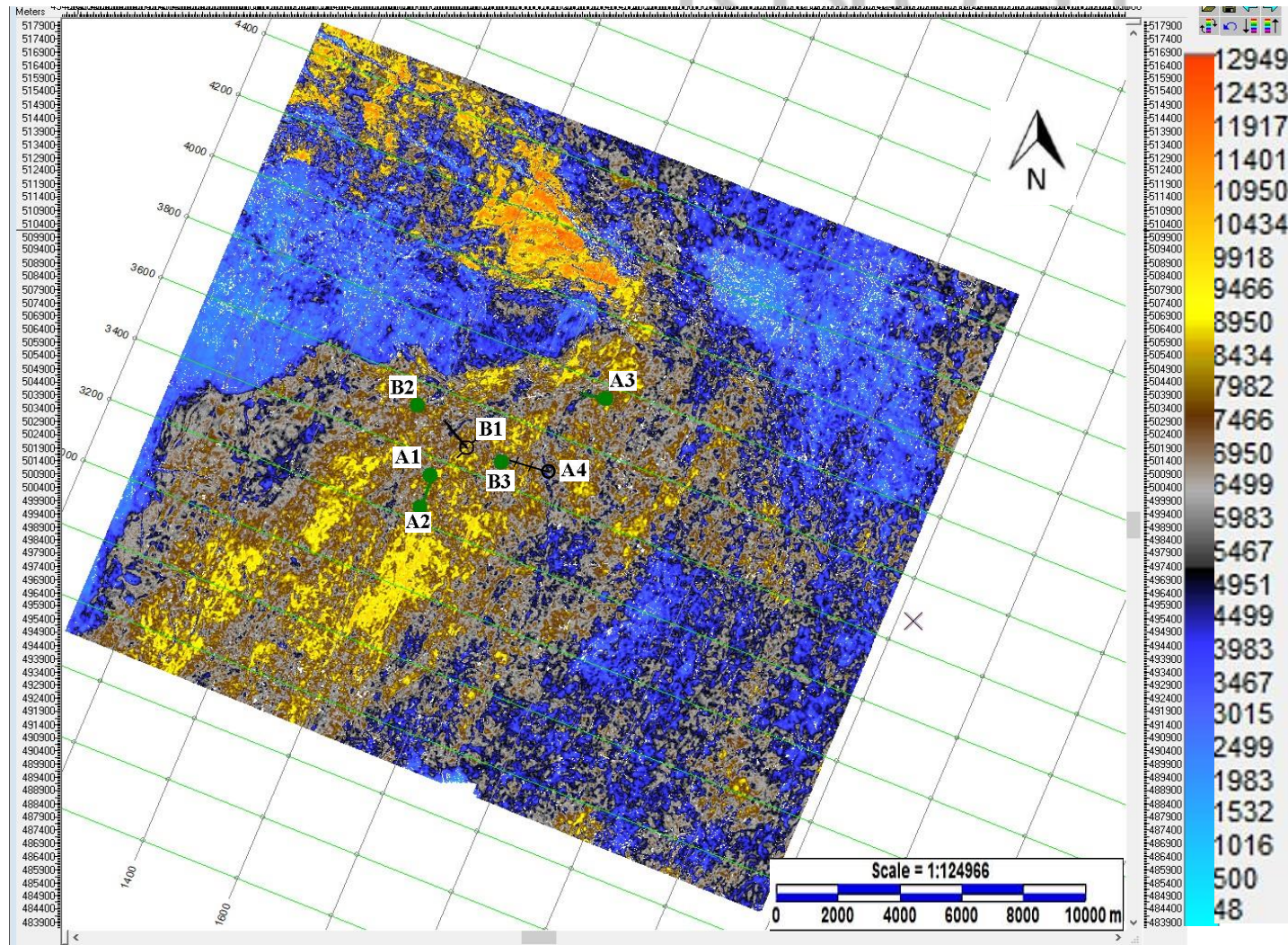


Figure 4.3 2 Map showing vatrms in the Fars

This vatrms was calculated using the fars data.

From the results in Figure 4.31 and 4.32, conducting the volumetric attribute extractions using the fars was selected as the most appropriate method for the subsequent upper interval volumetric calculations.

4.5.3 Vatrms Nears and Fars for Middle Shale and Base of Reservoir interval

4.5.3.1 Vatrms nears

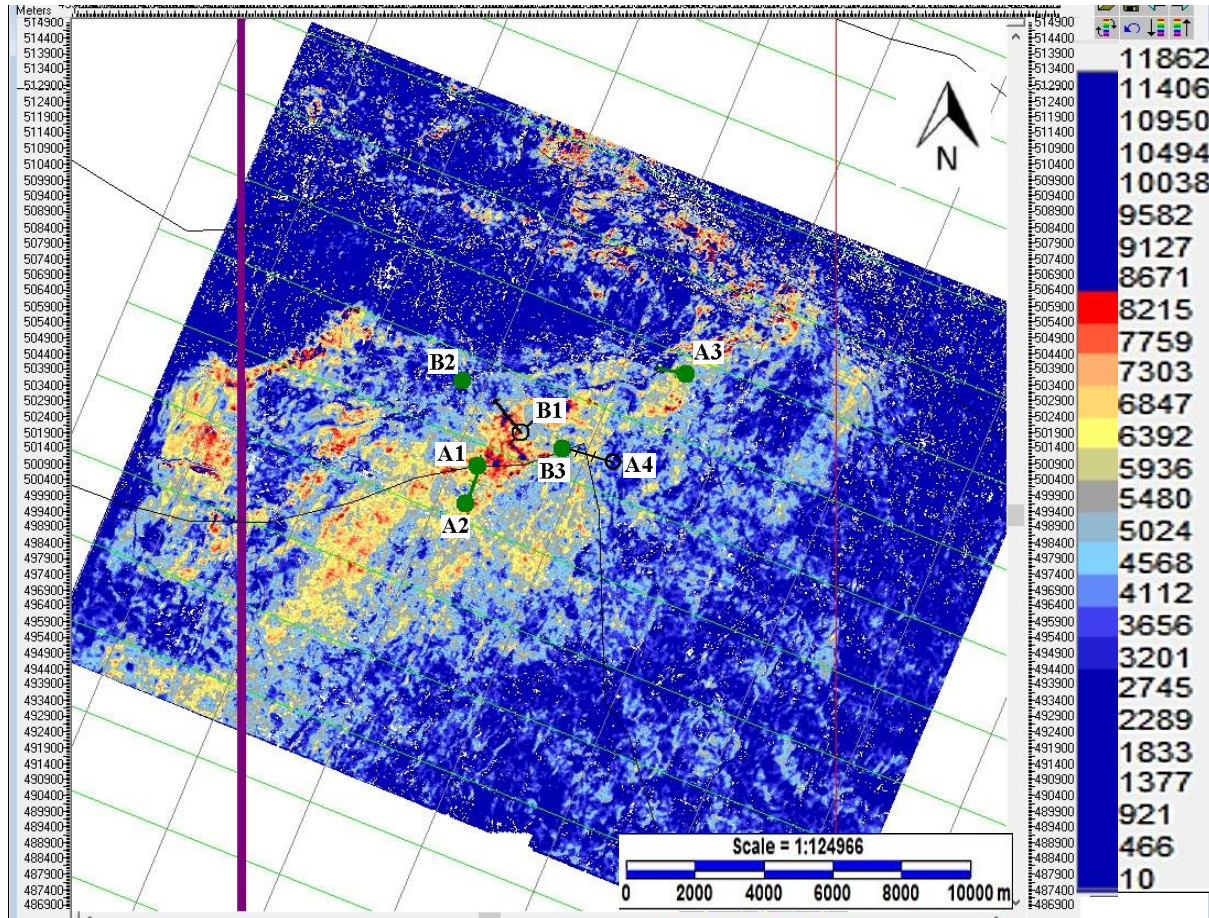


Figure 4.33 Map showing vatrms in the Nears

4.5.3.2 Vatrms Fars

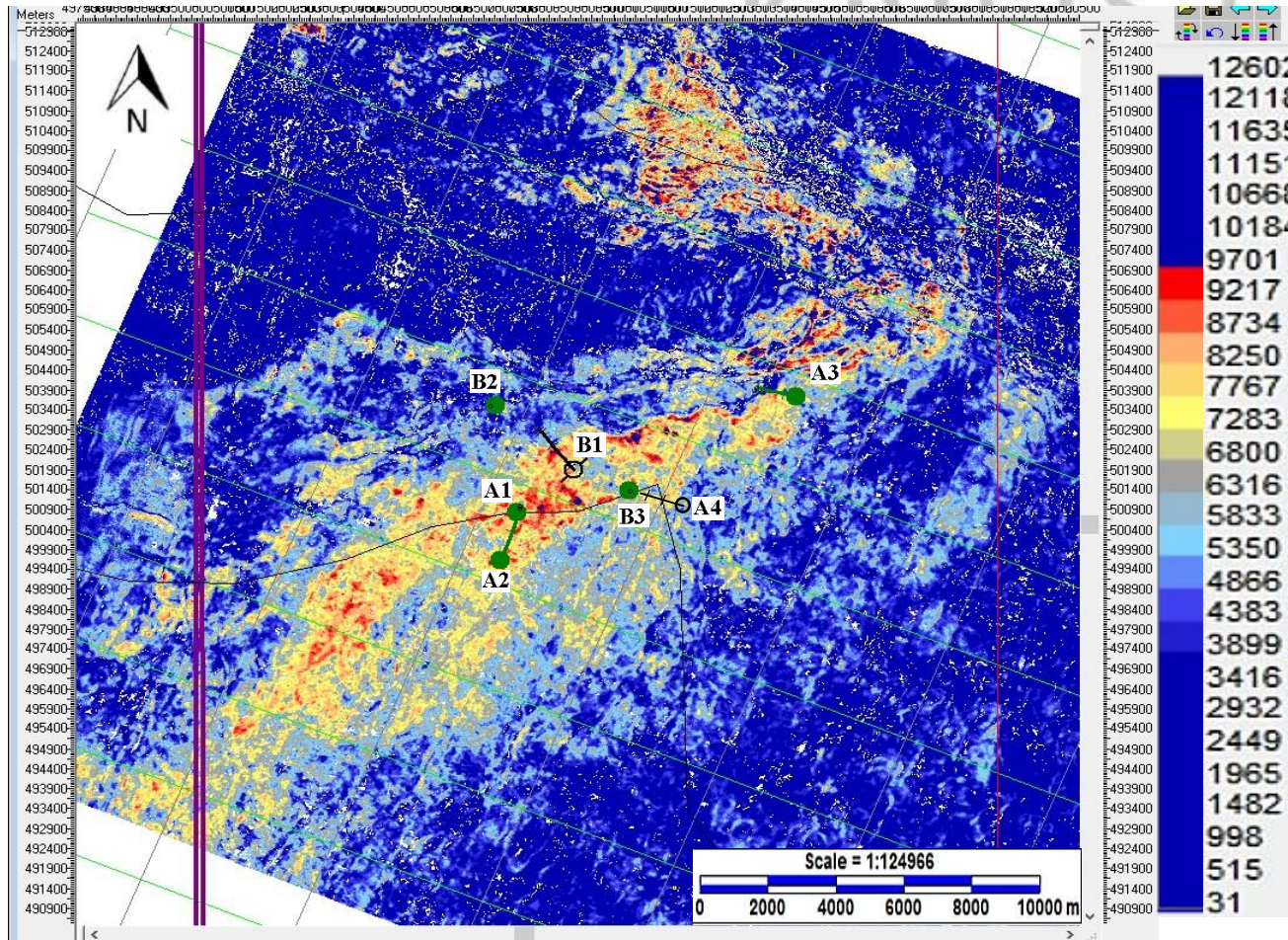


Figure 4.34 Map showing vatrms in the fars

After comparing Figure 4.33 and 4.34, the fars was selected and used for subsequent volumetric calculations in the lower interval.

4.5.4 Vatrms Responses from Different Intervals in the Reservoir

4.5.4 All the line colours mentioned in this section are collectively displayed in Figure 4.42 **Vatrms Responses from Different Intervals in the Reservoir**

4.5.4.1 Vatrms Between Top Upper and Middle Shale Giving Red Lines

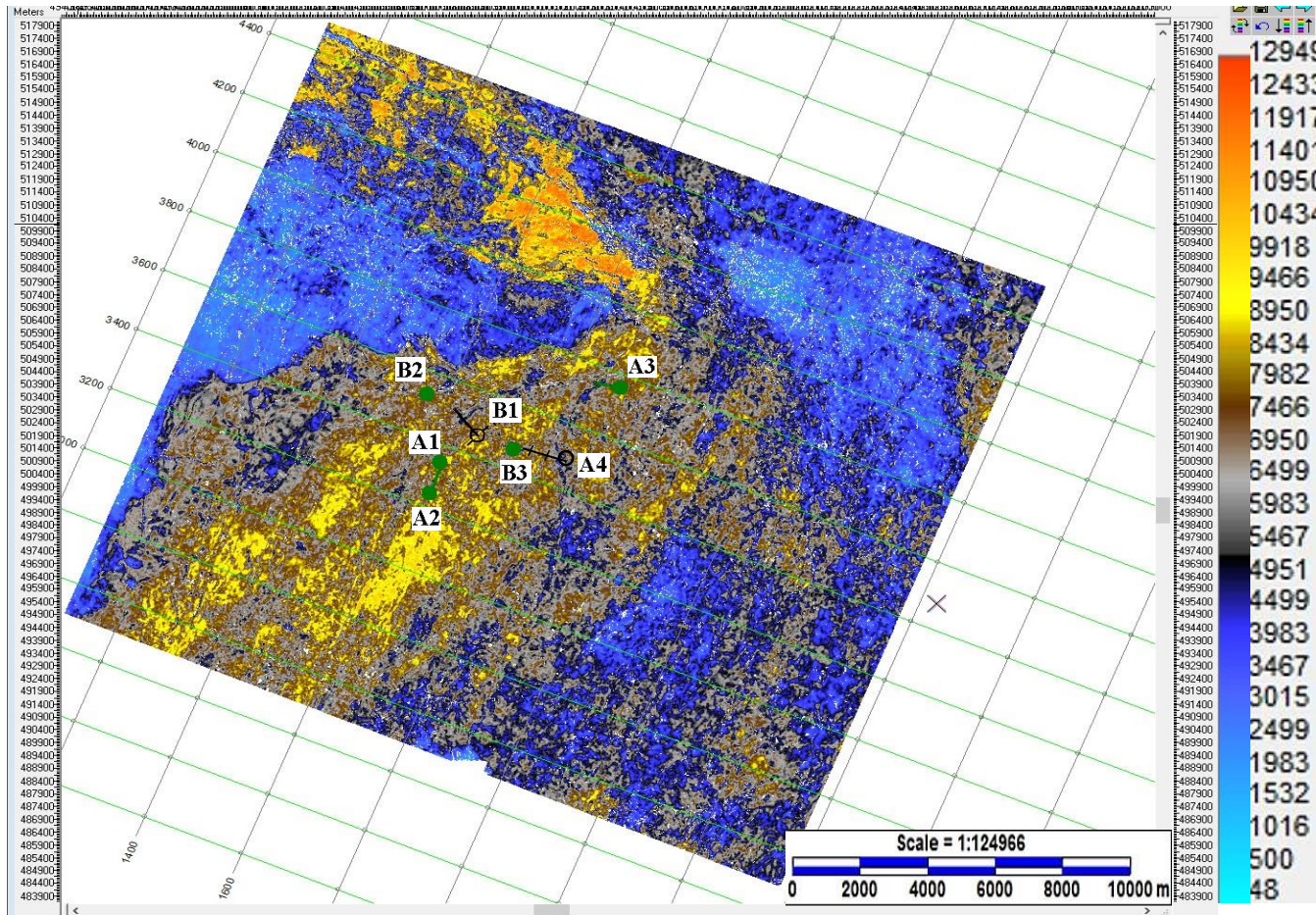


Figure 4.35 Map showing vatrms between Top Upper and Middle Shale giving red line

The bright spots of relatively very high amplitudes above the Tano nose are indicative of a massive sand presence. This confirms the earlier assumption that the source of the reservoir is located from that region and migrated south-eastwards to regions of greater depths, where they were accumulated.

4.5.4.2 Vatrms between Middle shale and base giving green line

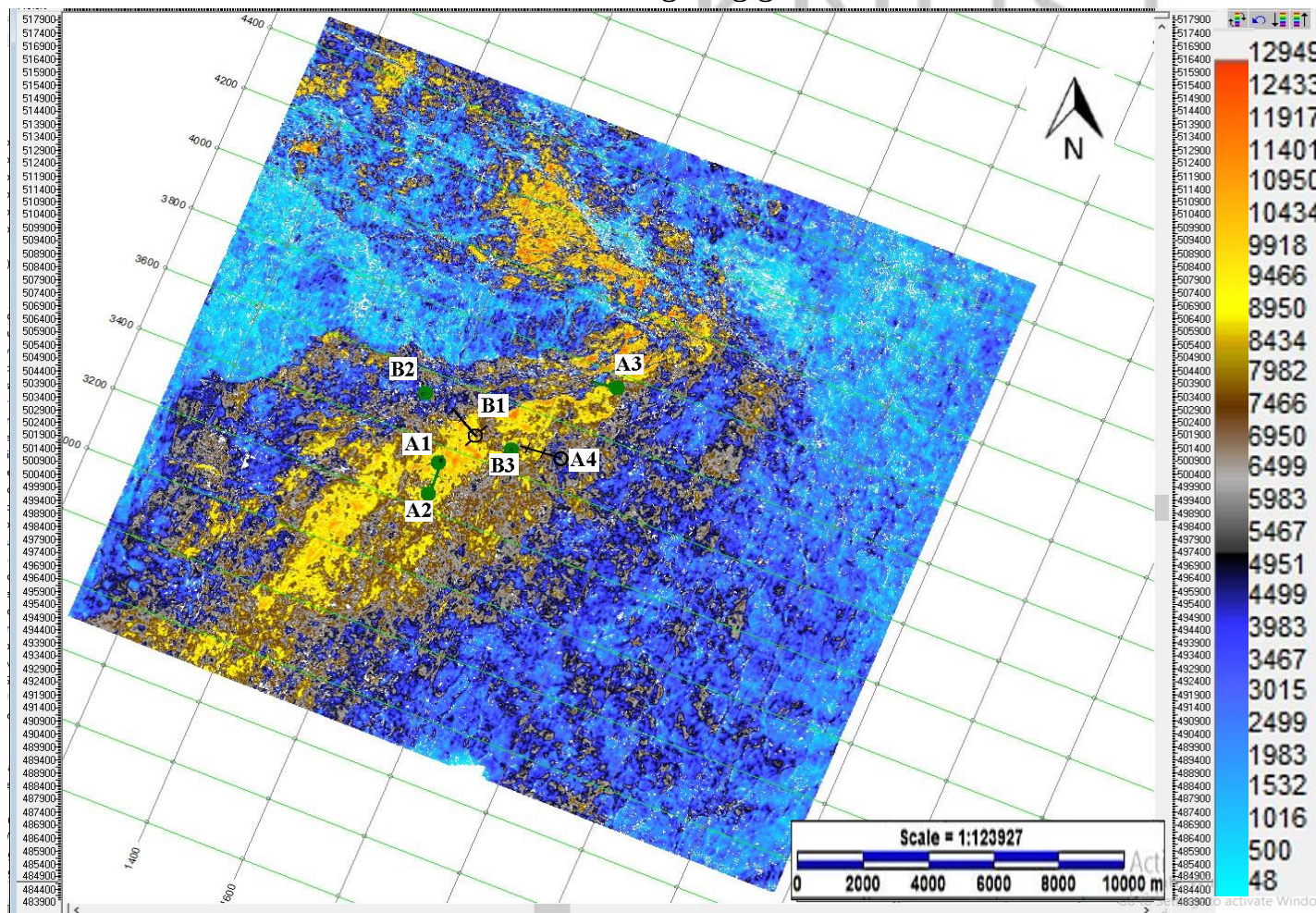


Figure 4.36 Map showing vatrms between the Middle Shale and Base giving green line

4.5.4.3

Vatrms between top upper and red line giving yellow line



4.5.4.4

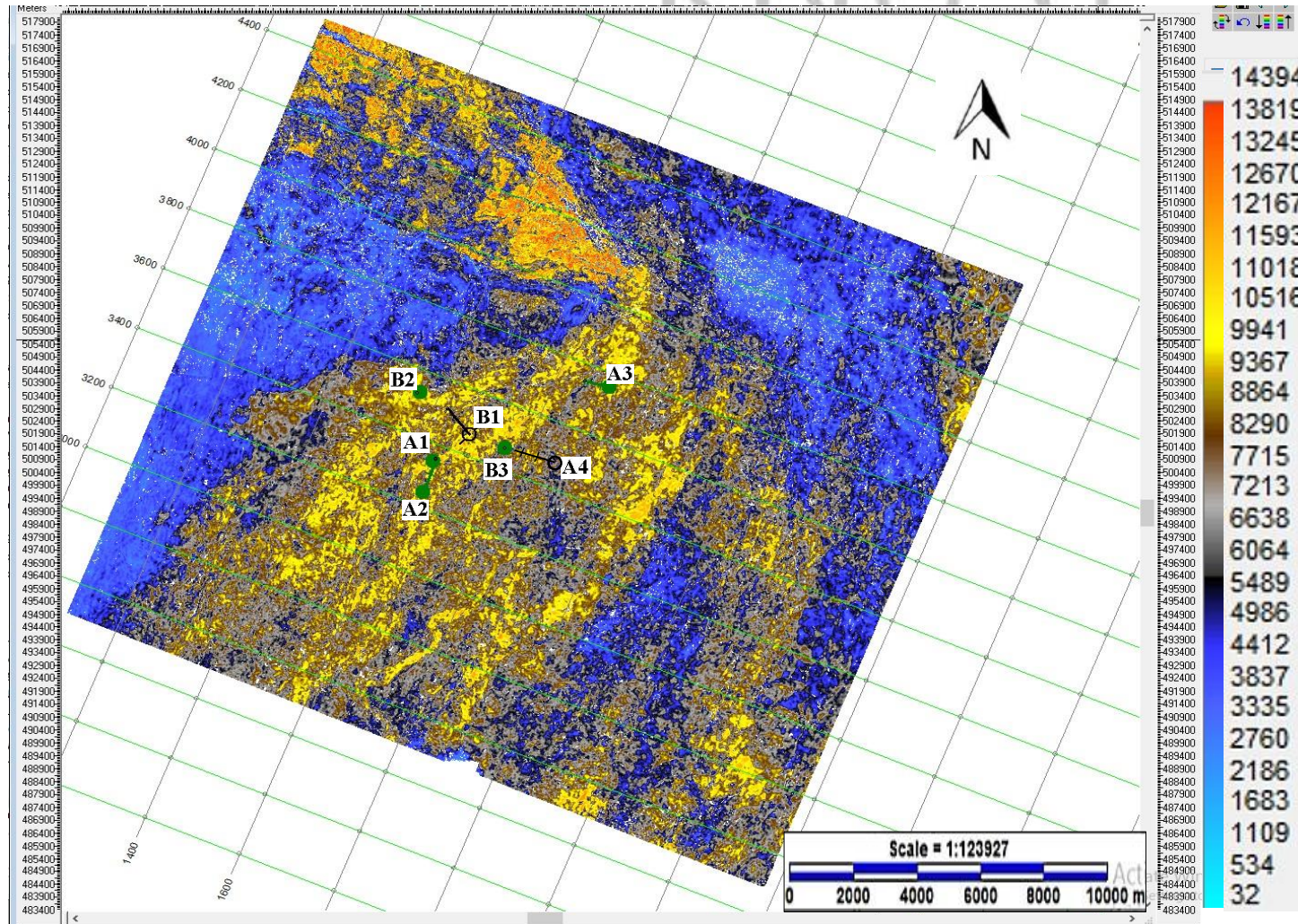


Figure 4.37 Map showing
vatrms between the Top
Upper Reservoir and red
line

4.5.4.5

Vatrms between red line and Middle shale giving gold line



4.5.4.6

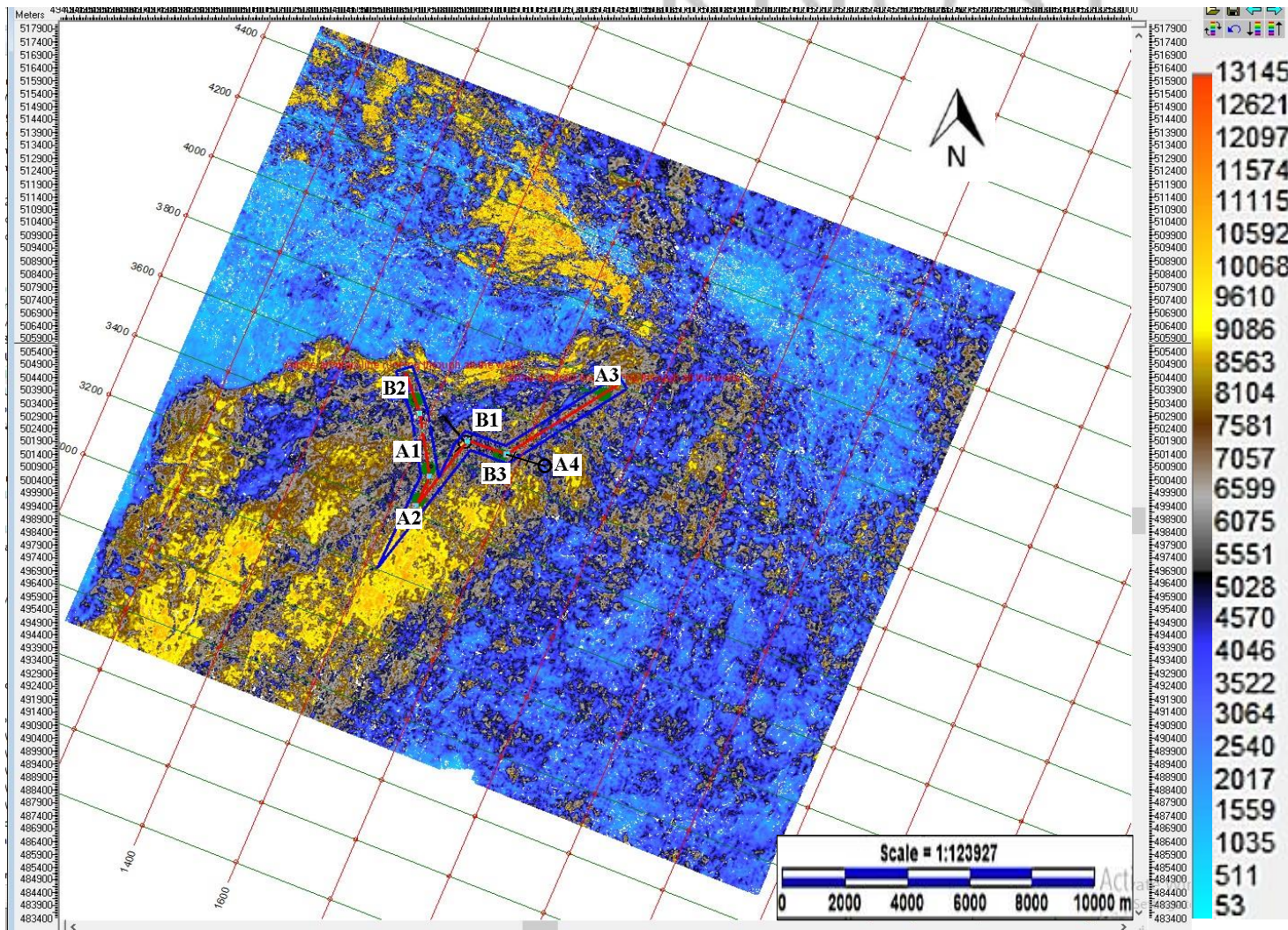


Figure 4.38 Map showing vatrms between the Red line and Middle shale giving gold line

4.5.4.7

Vatrms between Middle shale and green line giving dodger blue line



4.5.4.8

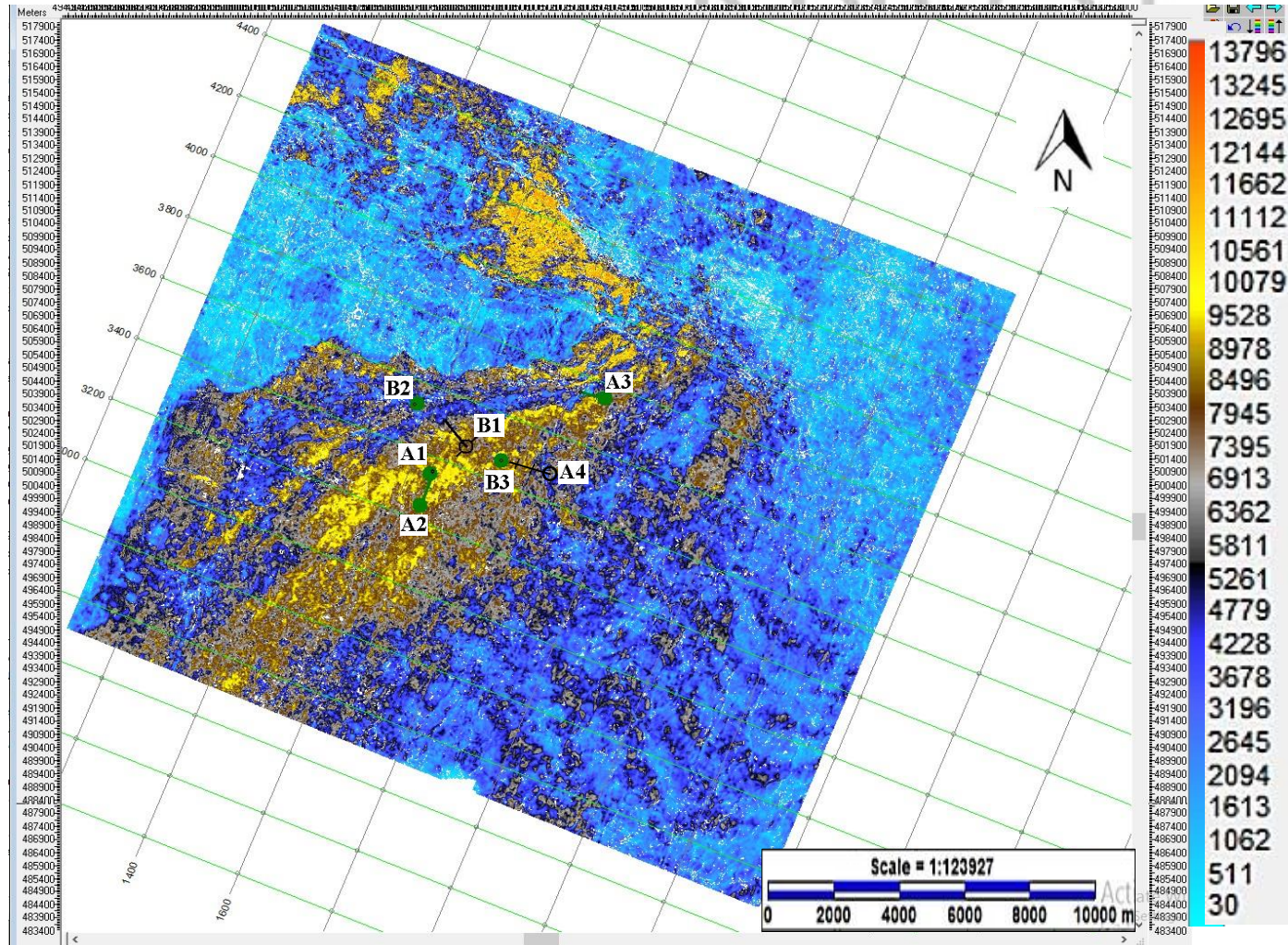


Figure 4.39 Map showing vatrms between Middle Shale and green line

4.5.4.9

Vatrms between green line and base giving grey line



4.5.4.10

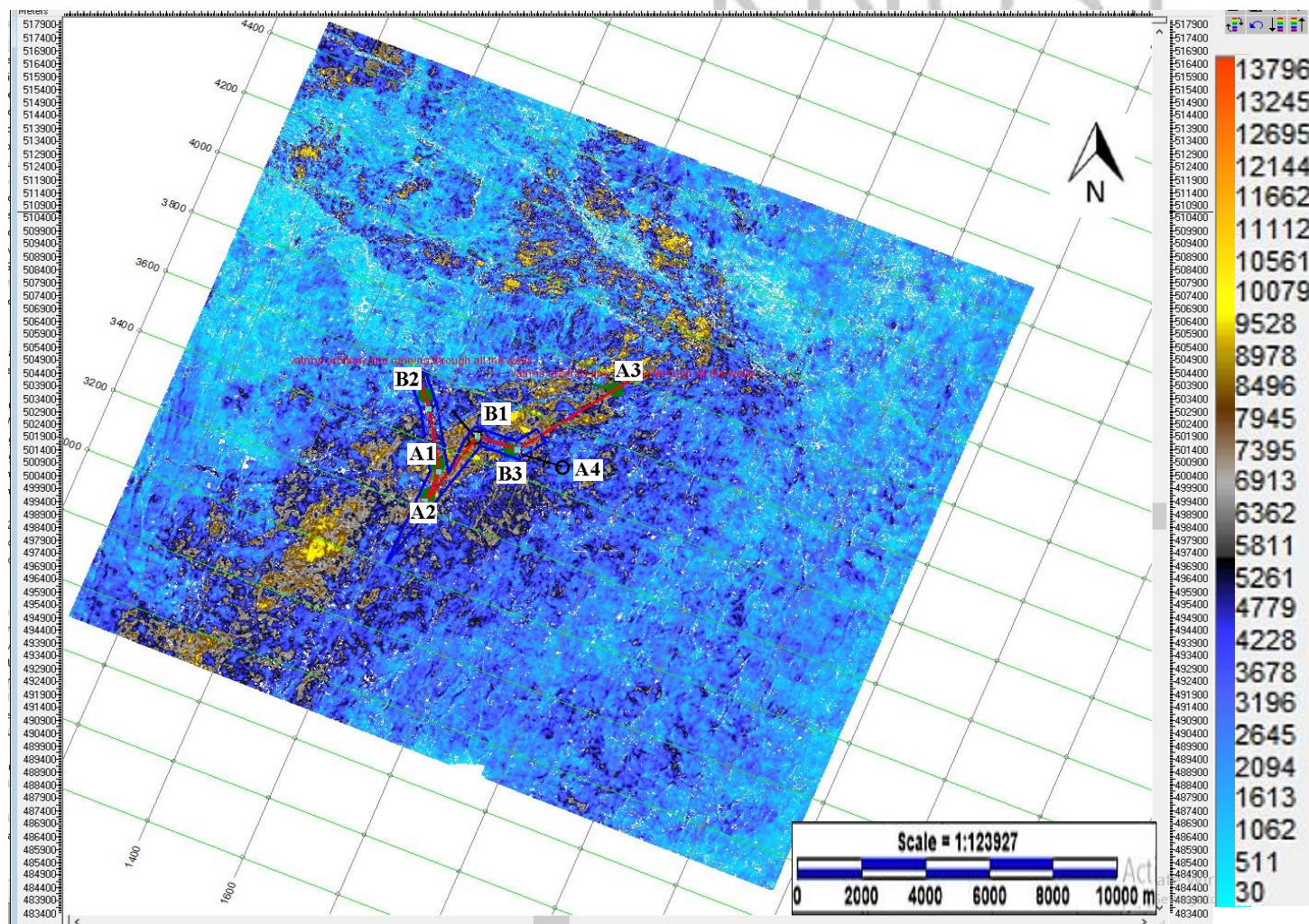


Figure 4.4 0 Map showing vatrms between the green line and Base of Reservoir

Looking at all the previous volumetric attribute calculations for the various intervals, it appears that all the vatrms extractions provided good quality attribute maps which clearly showed the sedimentology pathway of the reservoir sands. This information is helpful in determining the intervals that would be selected for the reservoir property calculations. This selection will be guided by the availability of at least one log in the interval of interest that displays hydrocarbon-bearing clean sands characteristics.

Arbitrary line showing vatrms lines for all the intervals considered
 Arbitrary line showing vatrms lines for all the intervals considered

Increasing Offset

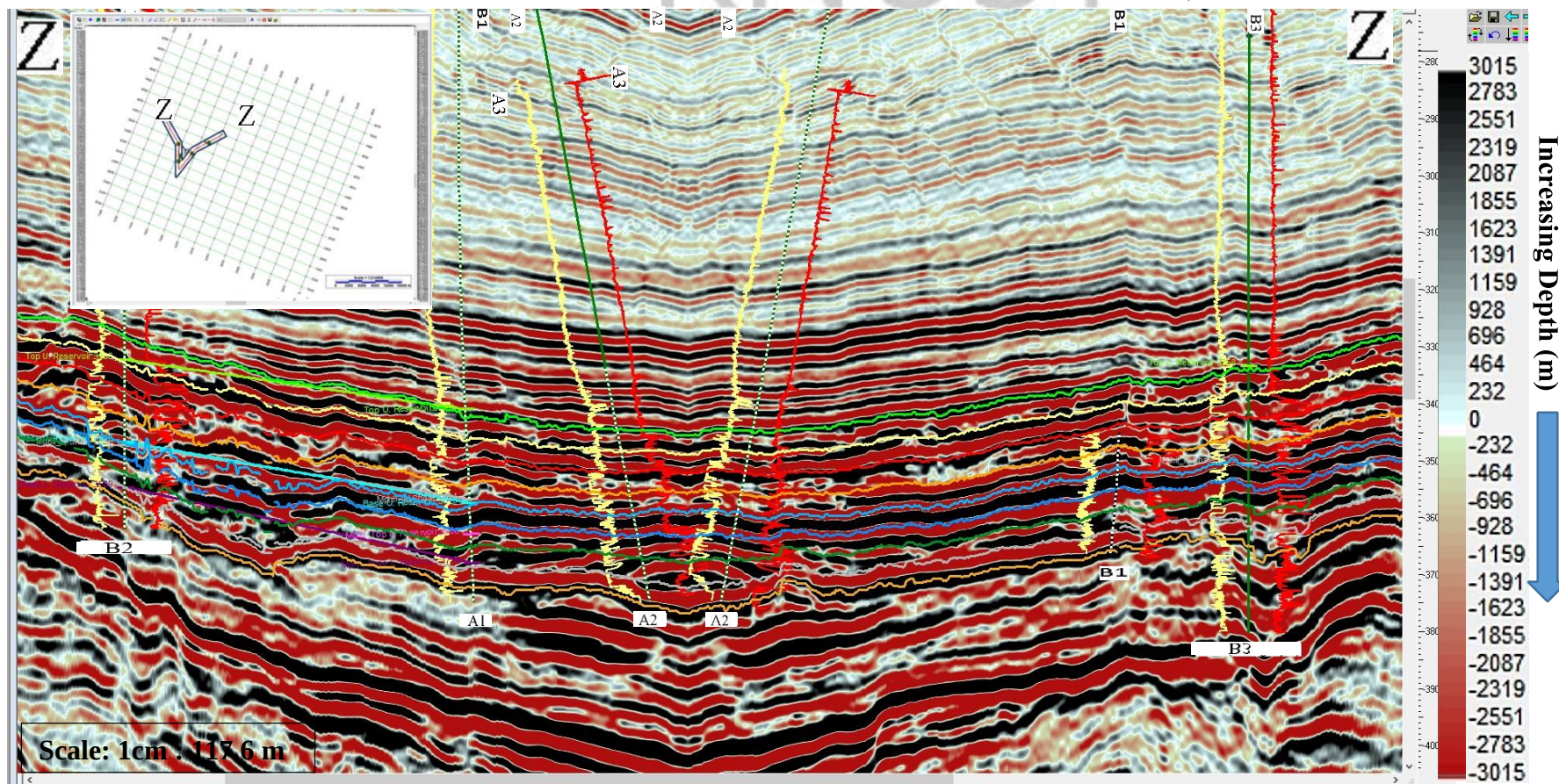


Figure 4.41 Arbitrary line showing vatrms lines for all the selected intervals

Figure 4.41 shows the result of all the vatrms extraction run on the data (i.e. the yellow, red, gold, dodger blue, green and grey lines represent the results from Figures 4.35 – 4.40).

4.6 MAPS USED FOR INTERVAL AND POLYGON SELECTION FOR PETROPHYSICAL CALCULATIONS IN THE EEI VOLUME



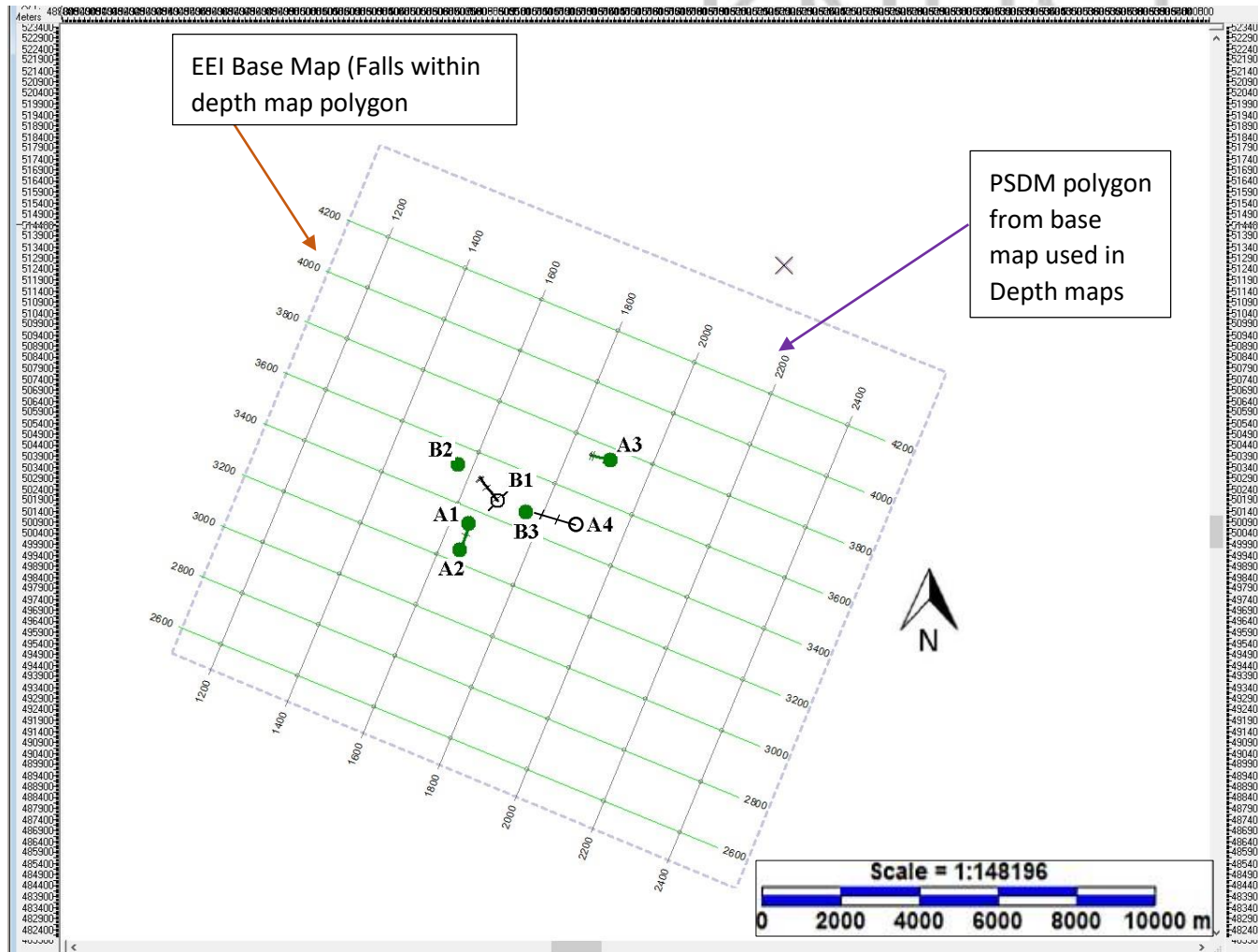


Figure 4.42 EEI base map

This figure represents the base map used for the volumetric attribute extractions on the EEI volume. It is located within the base map of the 3D depth volume seismic data and consists of seven inlines and nine crosslines. The seismic lines of the depth data exported into the EEI volume therefore fell within this base map.

4.6.1 Upper Interval- Between Top Upper Reservoir and Middle Shale

4.6.1.1 EEI Vatrms

4.6.1.1 EEI Vatrms

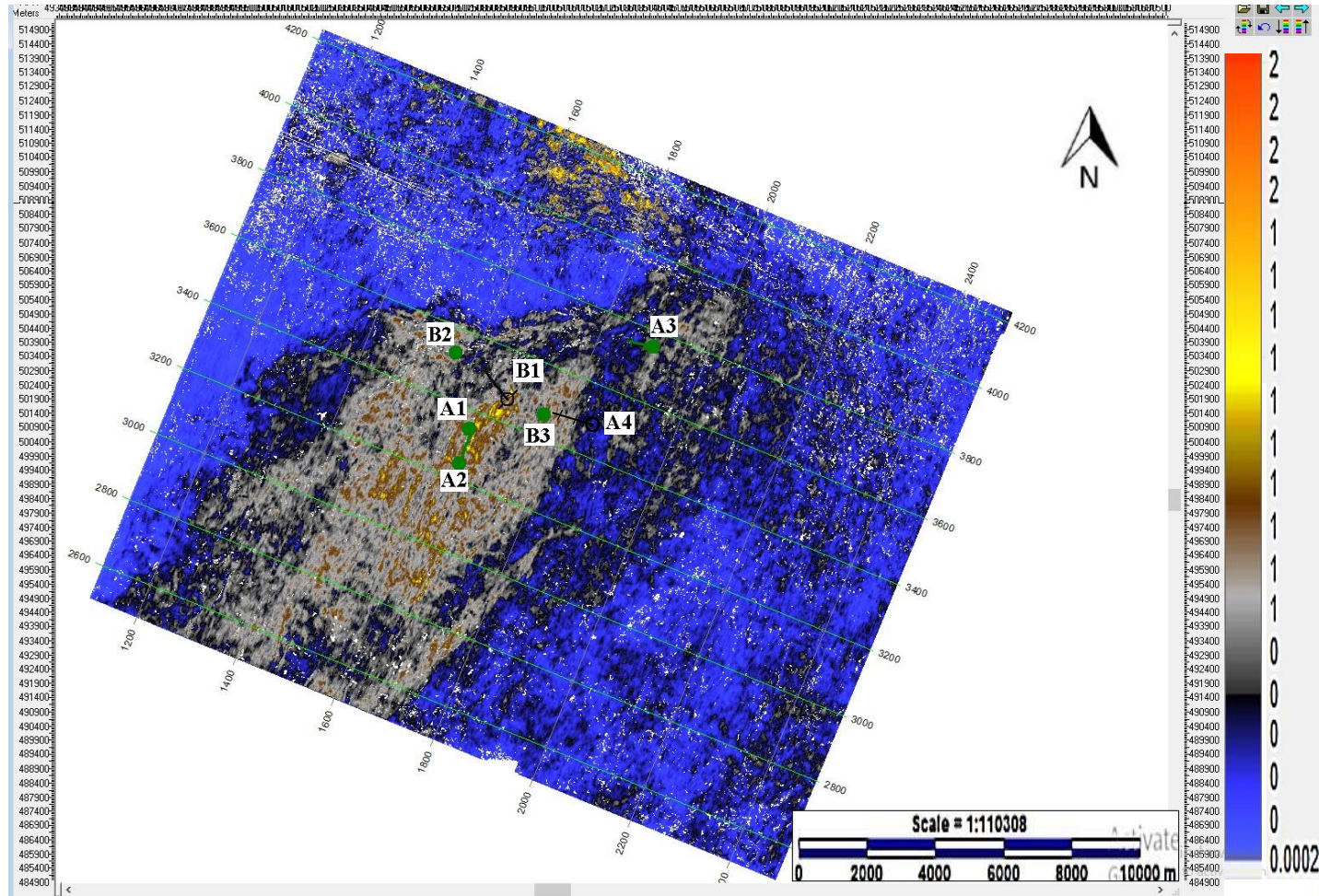
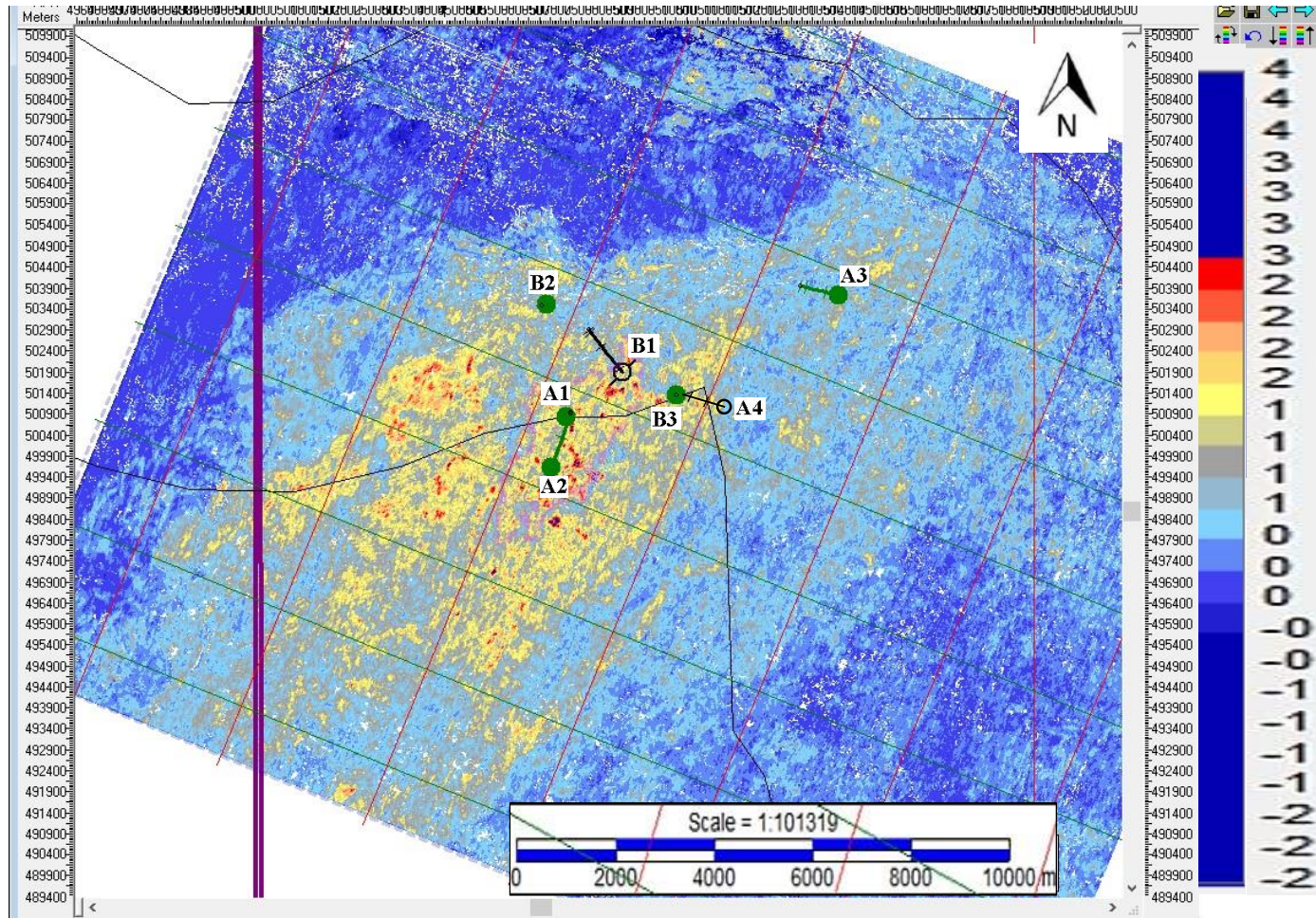


Figure 4.43 Map showing EEI vatrms between Top Upper and Middle shale

4.6.1.2 EEI Vatmax

4.6.1.2 EEI Vatmax

Figure 4.44 Map showing EEI vatmax between Top Upper Reservoir and Middle Shale

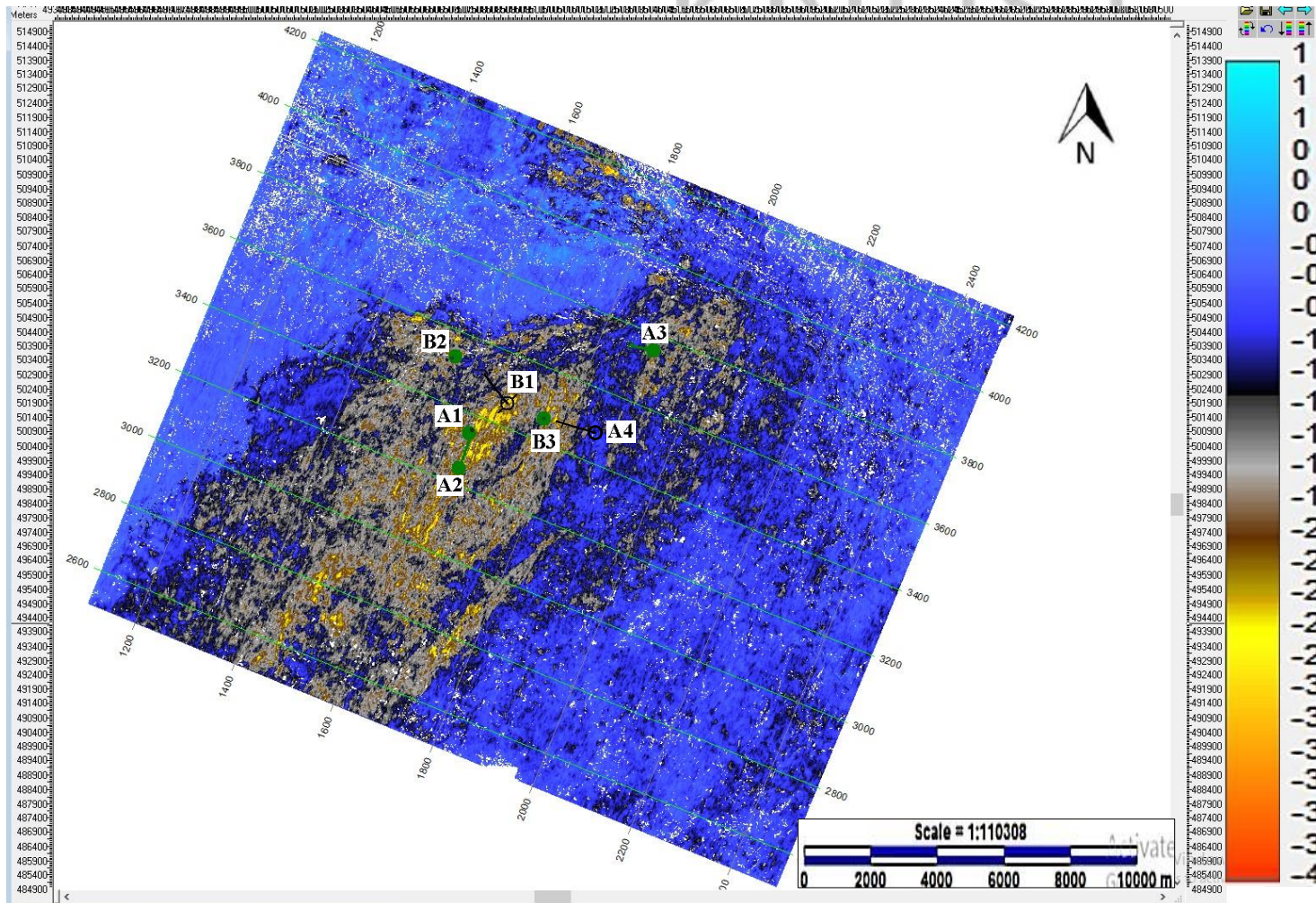


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4.6.1.3 EEI Vatmin
4.6.1.3 EEI Vatmin

Figure 4.45 Map showing





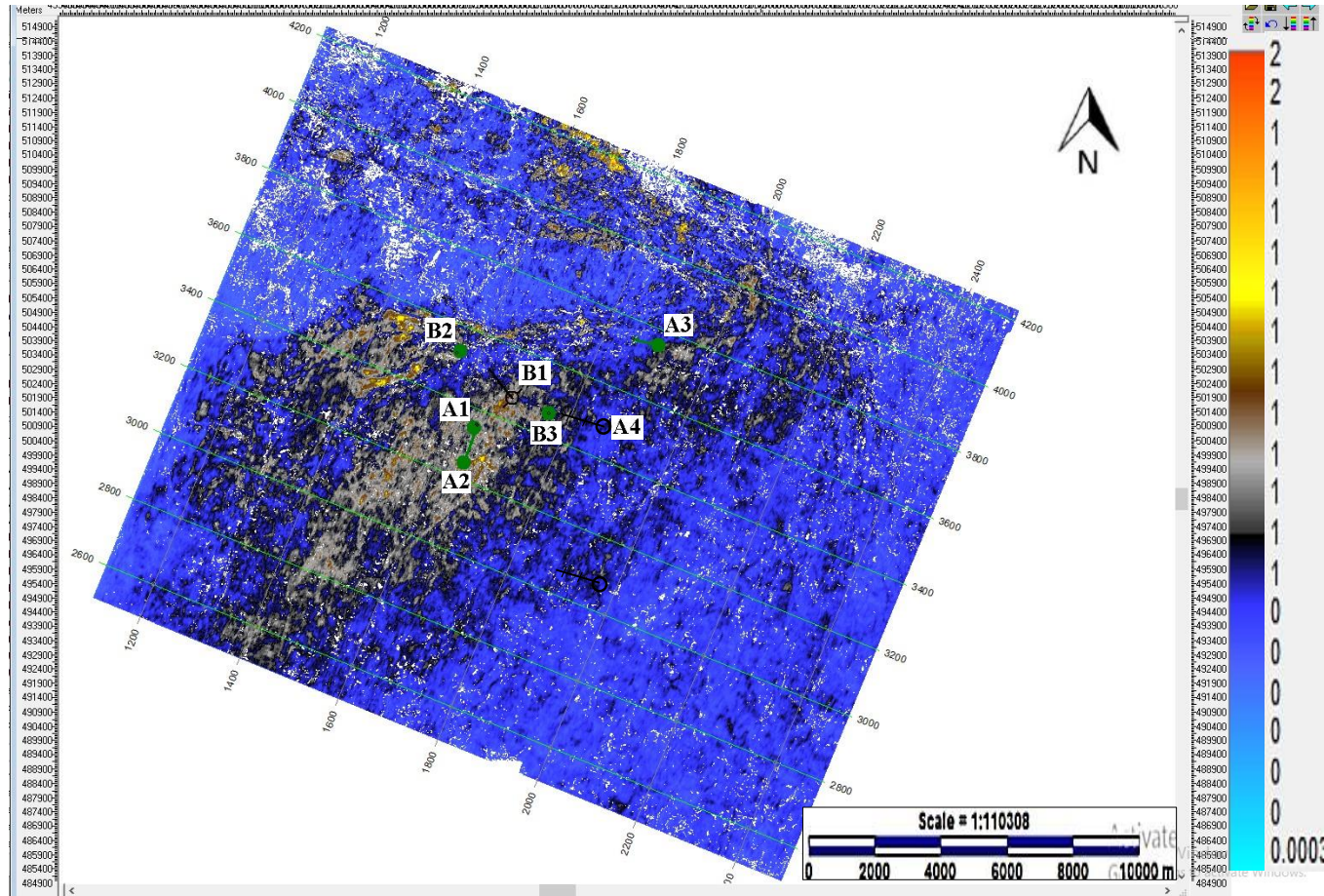
EEI vatmin between Top Upper Reservoir and Middle Shale

Comparing Figure 4.43, 4.44 and 4.45, the *vatmin* extraction gives a better image and will henceforth be used in the selection of polygons and intervals in the EEI petrophysical calculations.

4.6.2 Lower Interval-Between Middle Shale and Base of Reservoir

4.6.2.1 EEI Vatrms

Figure 4.46 Map showing EEI

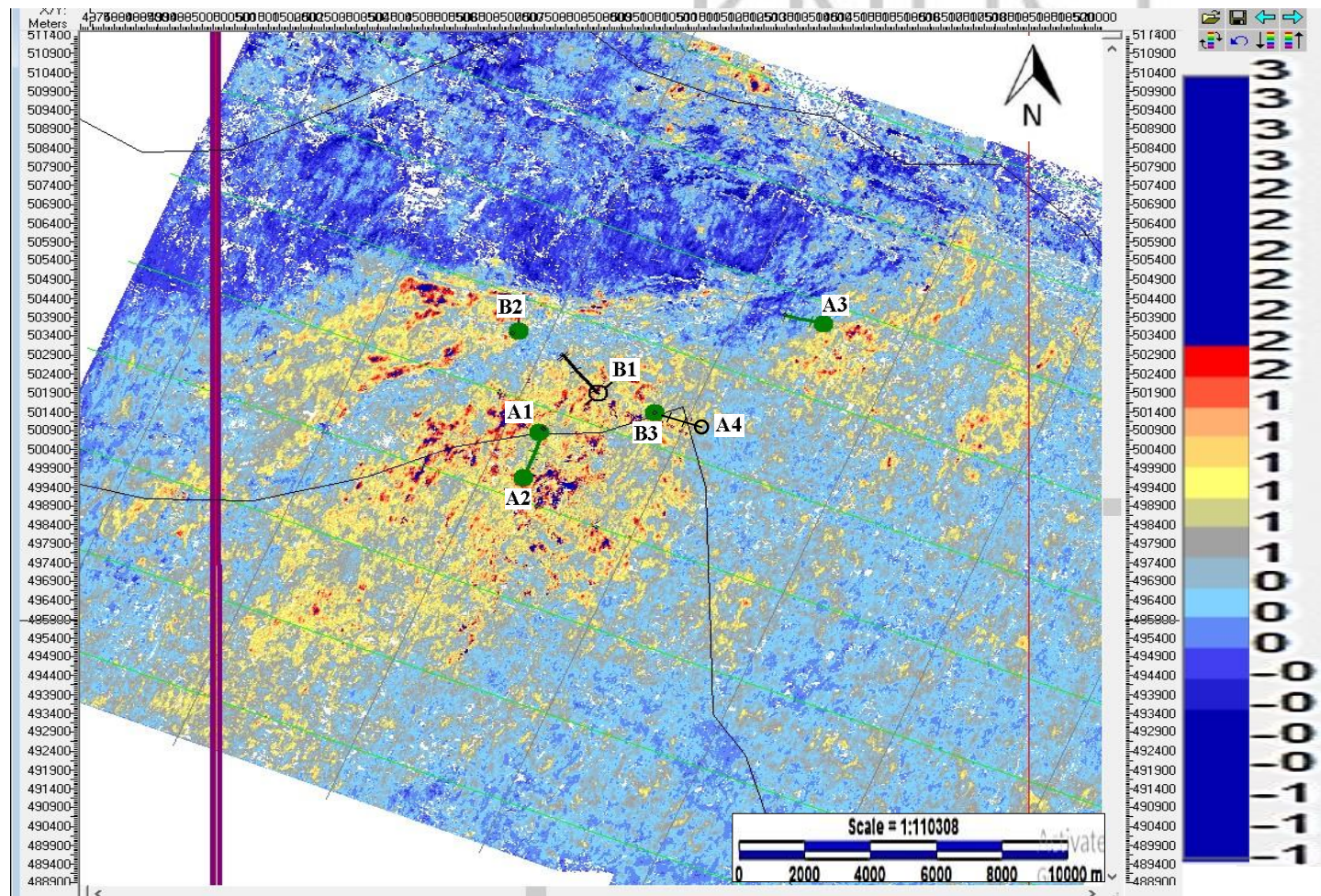


vatrms between Middle Shale and Base

4.6.2.2 EEI Vatmax

4.6.2.2 EEI Vatmax

Figure 4.47 Map showing EEI



vatmax between Middle Shale
and Base

4.6.2.3 EEI Vatmin 4.6.2.3 EEI Vatmin

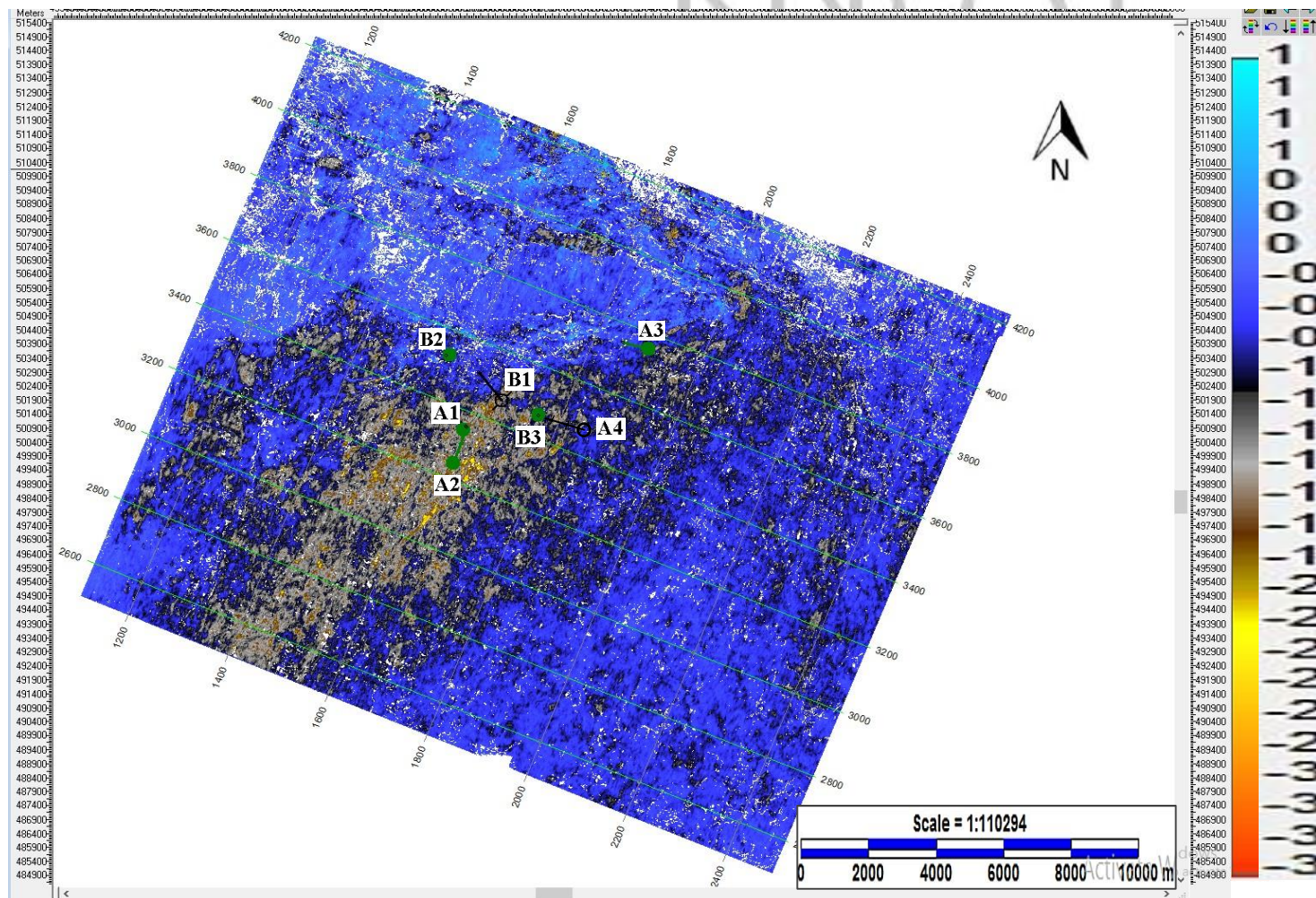


Figure 4.48 Map showing EEI vatmin between Middle Shale and Base

No polygon could be digitized from any of the maps in the lower interval of the EEI data as there was no definite geological body due to the nature of the lithological distribution of the sands in the reservoir. This was further confirmed by running contoured structure and thickness maps for the polygon digitized around the sand interval in the upper interval, which is shown in section 4.7.

4.7 EEI POLYGON MAPS FOR UPPER INTERVAL

4.7.1 Structure Maps

4.7.1.1 Upper Boundary (Top Upper Reservoir) UP1 C.I 6.0 m

4.7.1.1 Upper Boundary (Top Upper Reservoir) UP1 C.I 6.0 m

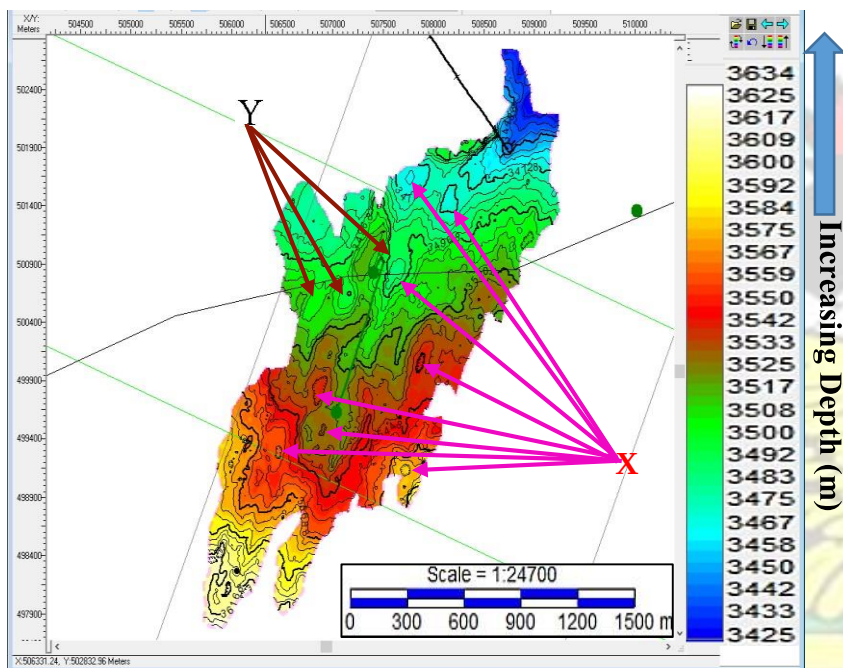


Figure 4.49 Contoured EEI structure map of UP1 of UP2

4.7.1.2 Lower Boundary (Middle Shale) UP2 C.I 6.0 m

4.7.1.2 Lower Boundary (Middle Shale) UP2 C.I 6.0 m

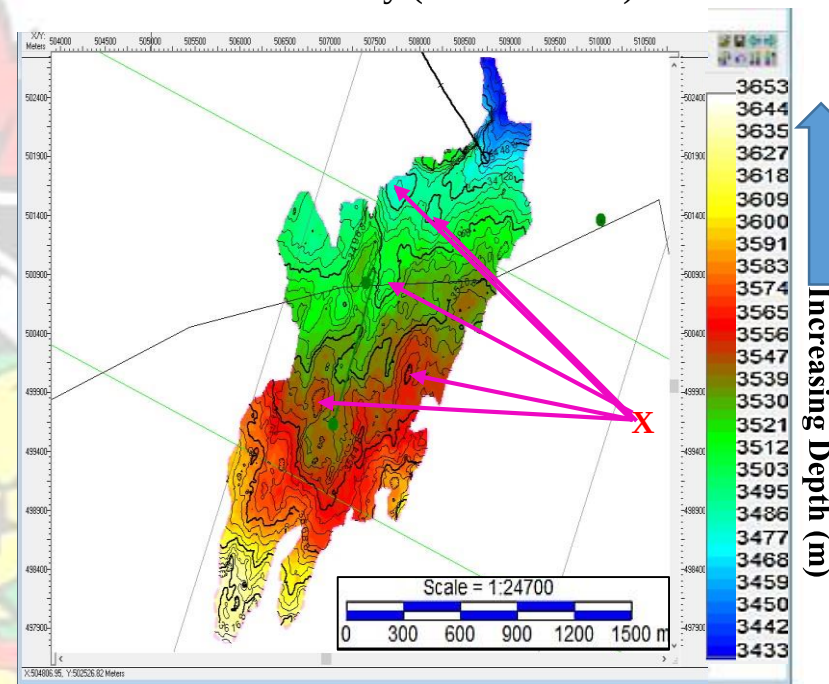


Figure 4.50 Contoured EEI structure map

This structure map reveals a general trend of increasing depth with increasing distance south-west wards in the down dip direction. A few four-way closures (X) and three three-way closures (Y) are evident on the contour map.

Depth variations range from 3425 m – 3634 m. in the down-dip direction.

Figure 4.49 and 4.50 are almost identical. This depicts horizontal homogeneity between UP1 and UP2. Just as in Figure 4.49, a few four way closures (X) can be observed on this map, with a depth increase from 3433 m - 3653 m in the down-dip direction.

4.7.2 Isochore (TVT) Map

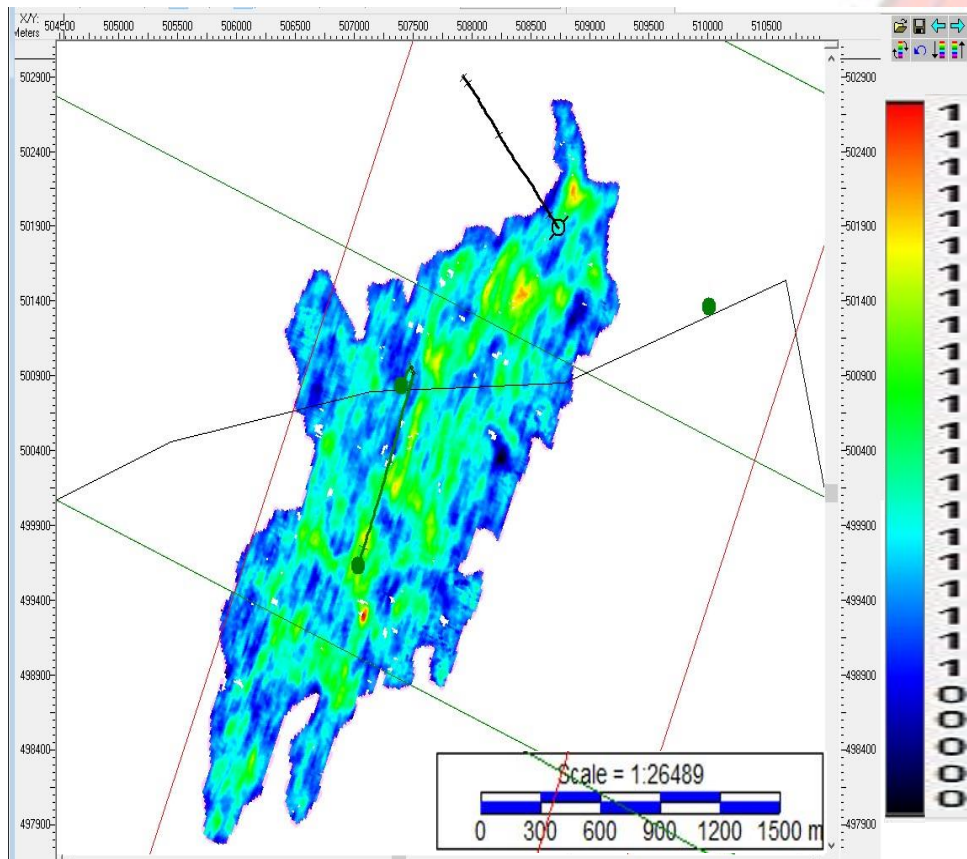


Figure 4.51 *EEI Isochore map*

From the map aside, it is clear that the EEI thickness map produced a poor image with no definite geological body due to the scattered nature of the sand distribution and because:

- 1) The area was not structurally confined (it consisted of just a dipping area with no major anticlines or synclines to trap the sands and hydrocarbons)
- 2) There was an un-uniform and uneven deposition of the sands which prevented the generation of maps with well-defined geological bodies
- 3) Unlike the depth maps where the reflectivities produced are a sum of all the sands present in the (reservoir which consequently results in the clear display of continuities), the EEI detects every individual sand-like response and groups them in terms of magnitude, resulting in poor maps when the sands are scattered in uneven concentrations

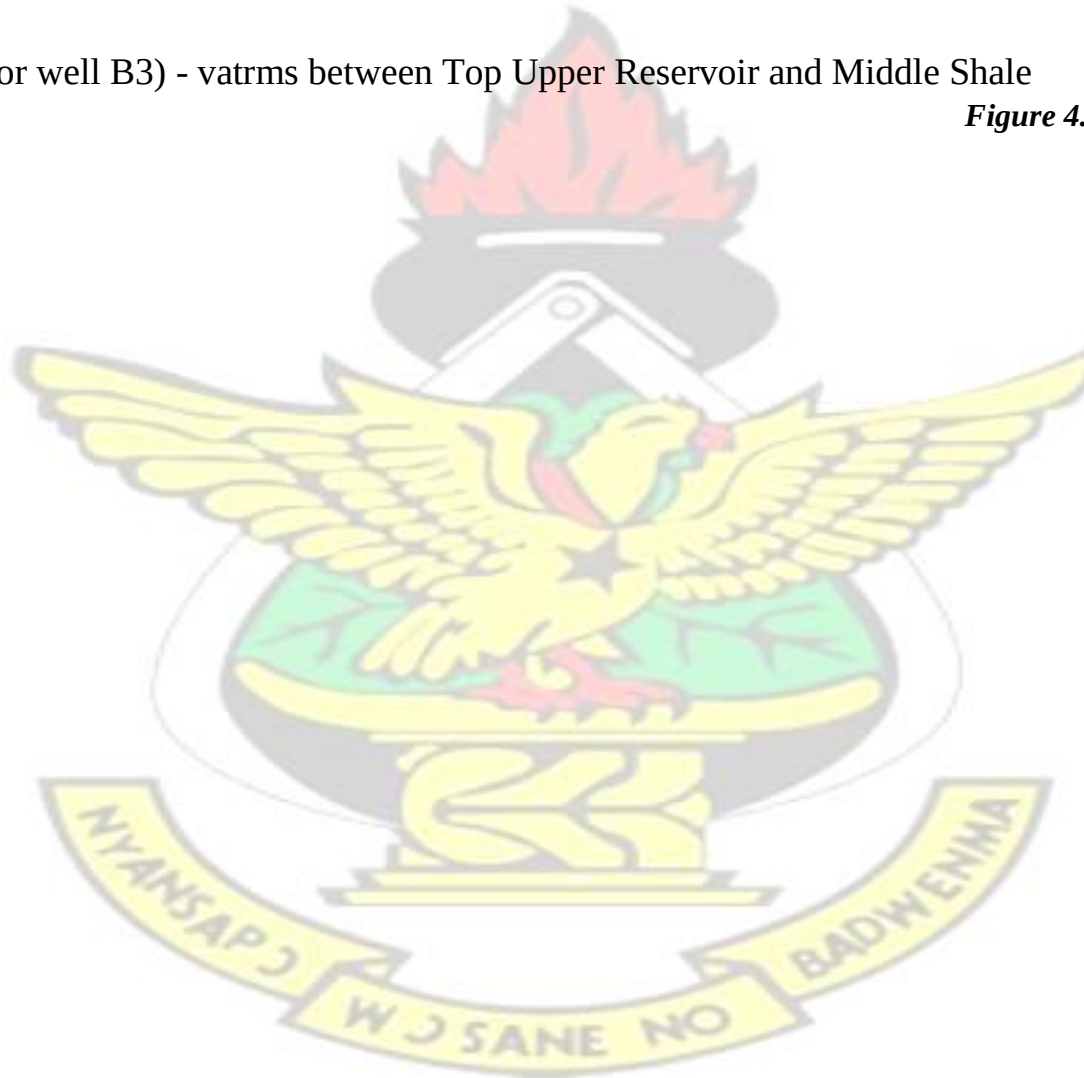
As a result, the EEI maps could not be used to calculate the gross reservoir sand volume within the polygon through the multiplication of the thickness map by the polygon surface area. All the petrophysical calculations thus had to be done in the Pre-Stack Depth migrated volume data instead.

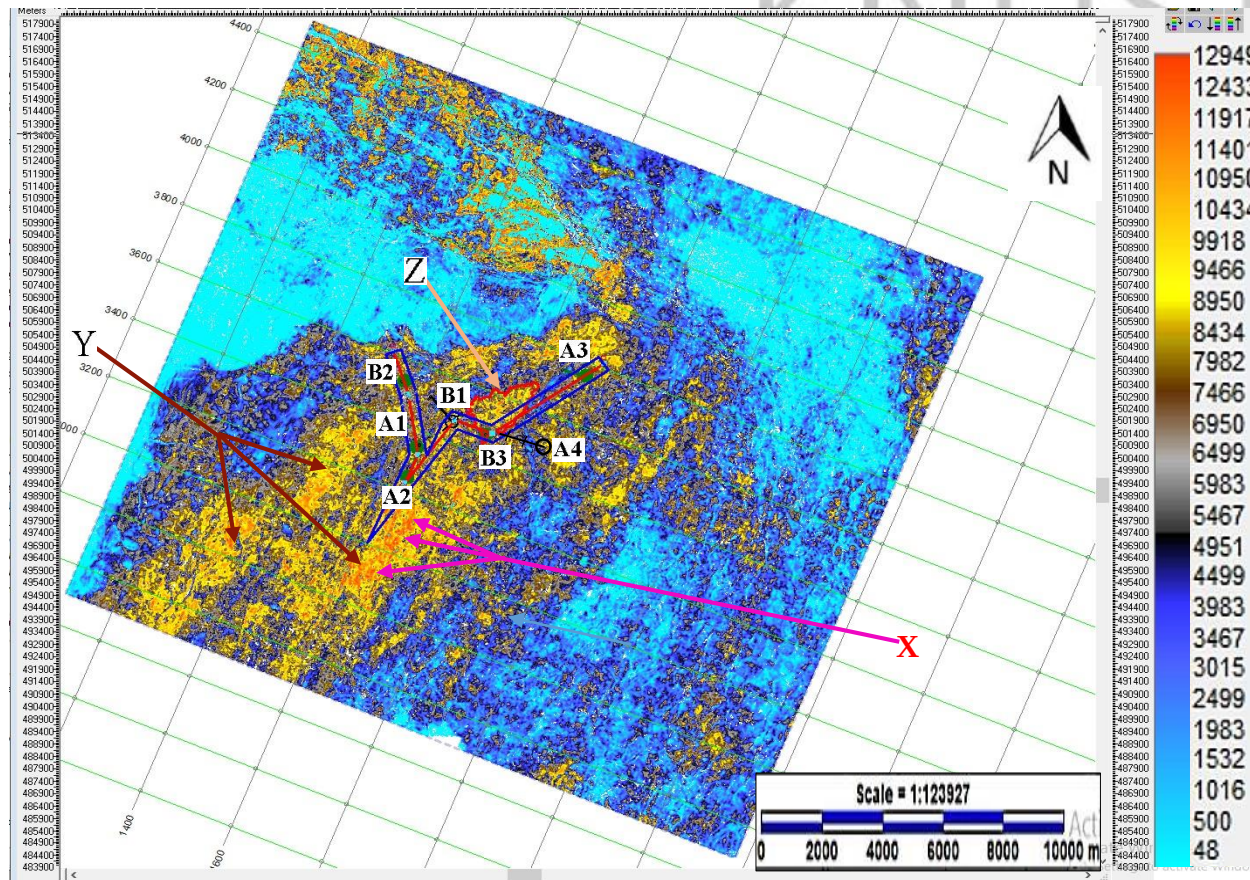
4.8 MAPS AND POLYGONS USED FOR PETROPHYSICAL ANALYSIS IN THE DEPTH VOLUME

4.8.1 Volumetric Maps

4.8.1.1. Upper Interval (For well B3) - vatrms between Top Upper Reservoir and Middle Shale

Figure 4.52 Map showing upper interval





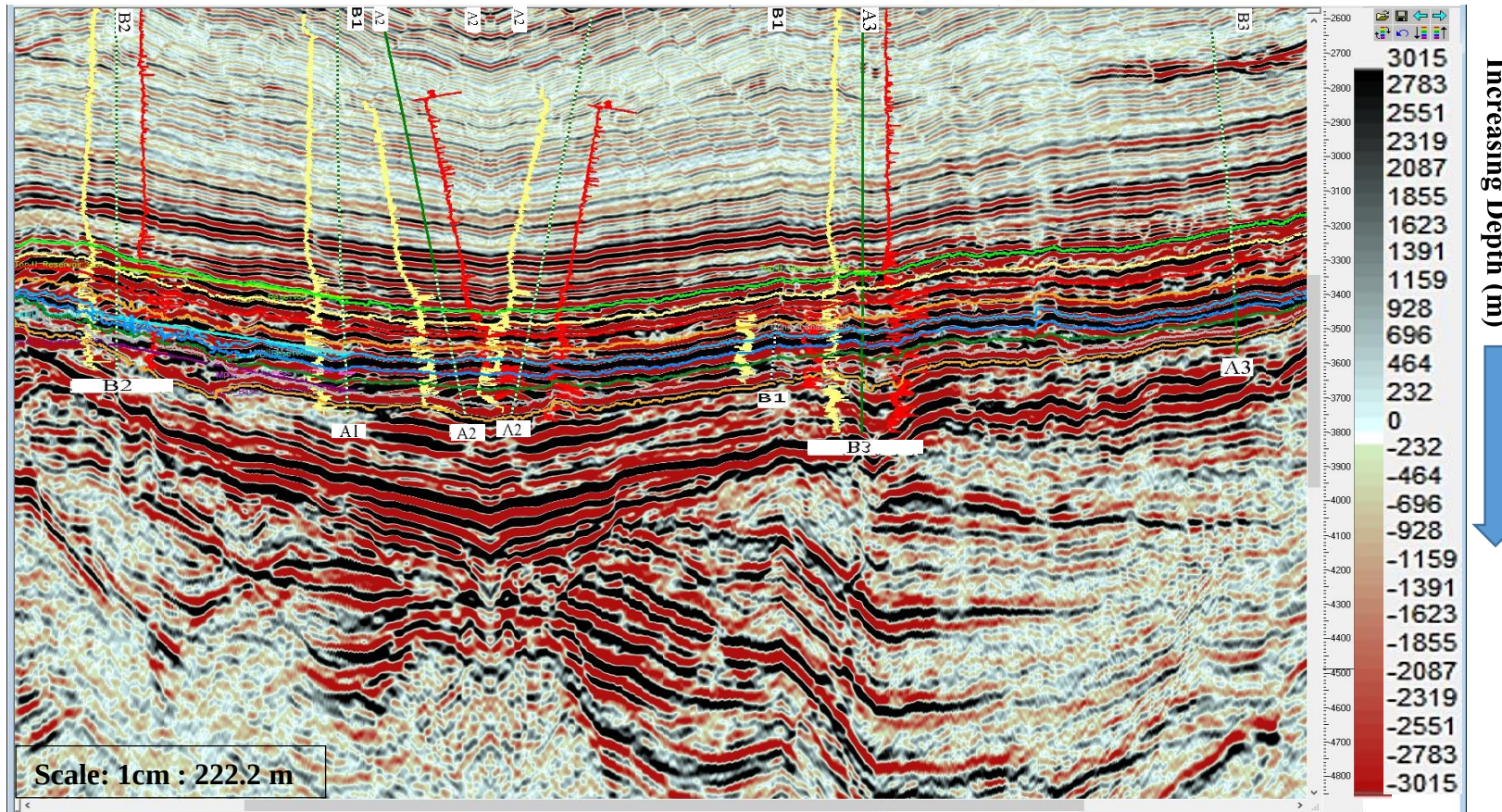
polygon (UP) from vatrms between Top Upper Reservoir and Middle Shale

This map reveals large and relatively continuous sand packages with the strongest reflections -indicated by the orange spots in the yellow regions (X)- located in the lower half of the map . The biggest zone containing the strongest reflections is indicated by the letter (Y). These zones of high amplitude responses however did not possess wells, making it difficult to obtain the log parameters required in petrophysical analysis. Other intervals also had good shows but could not be used due to the absence of a resistivity log, since the hydrocarbon potential could not be estimated. The digitized polygon of choice for further petrophysical evaluation therefore became the red polygon (Z). This polygon was named Upper Polygon (UP).

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Arbitrary line passing through the polygon
Arbitrary line passing through all the polygon

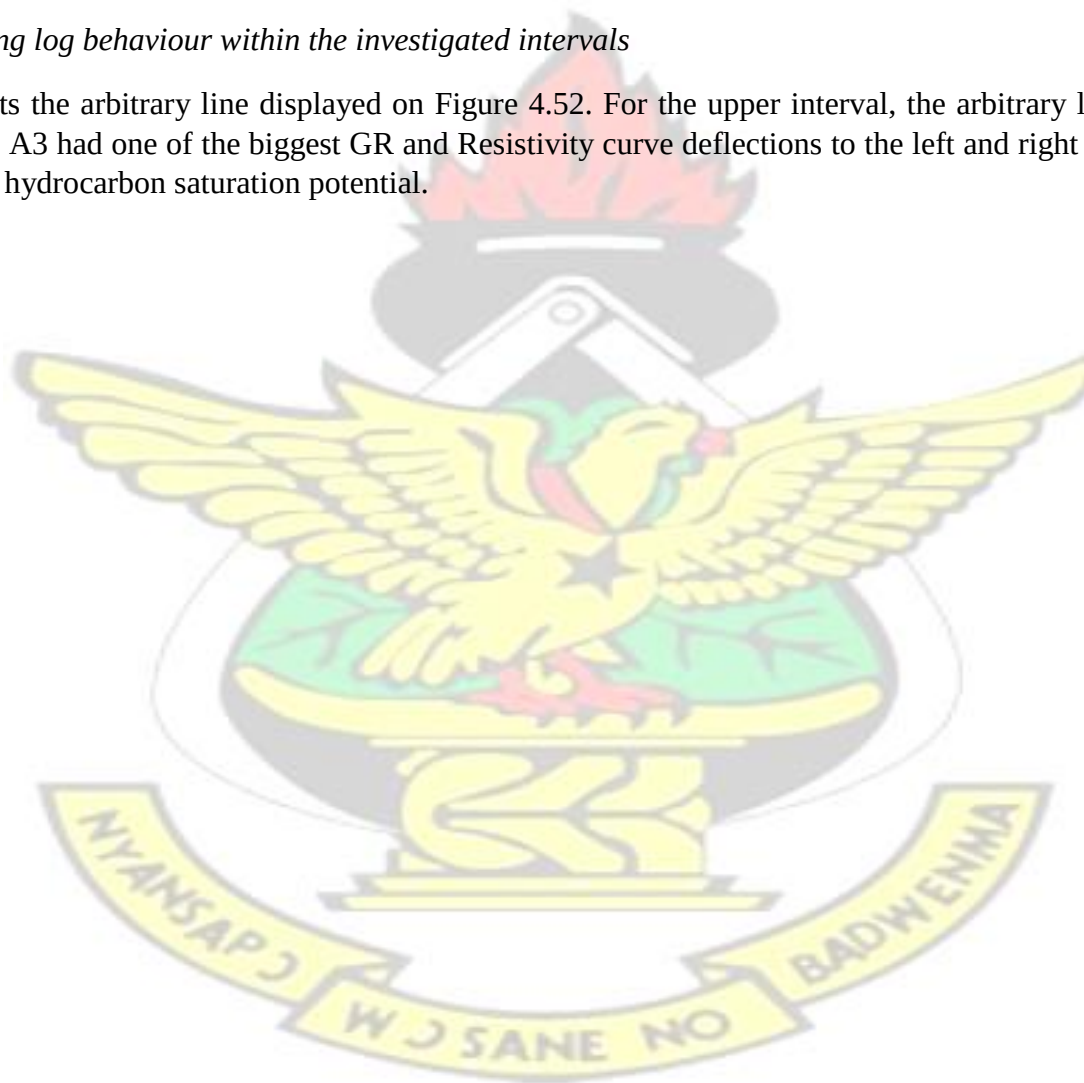
Increasing Offset



KNUST

Fig 4.53 Arbitrary line showing log behaviour within the investigated intervals

This seismic section represents the arbitrary line displayed on Figure 4.52. For the upper interval, the arbitrary line running through Figure 4.52 revealed that well A3 had one of the biggest GR and Resistivity curve deflections to the left and right respectively. This is indicative of a zone with high hydrocarbon saturation potential.



4.8.1.2 Lower Interval (for well A2)- vatrms between Middle shale and base

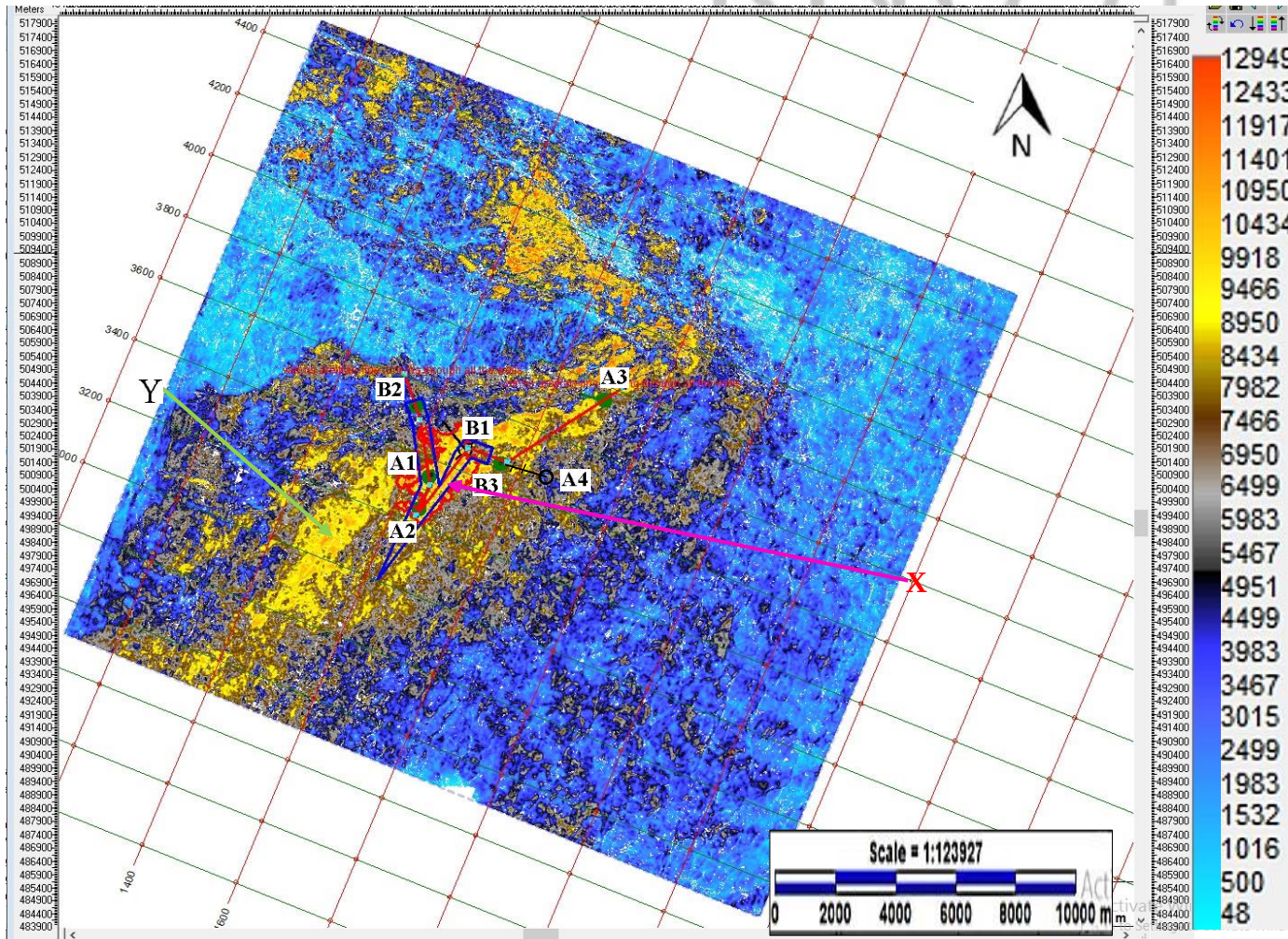


Figure 4.54 Map showing lower interval polygon (LP) from vatrms between Middle Shale and Base of Reservoir

This map displayed a beautiful clear sediment migration path with a continuous sand package that moved from the reservoir source to the deepest parts of the map (the base) where it accumulated (Y). For reasons similar to the upper interval, the most appropriate choice of polygon for this interval was (X).

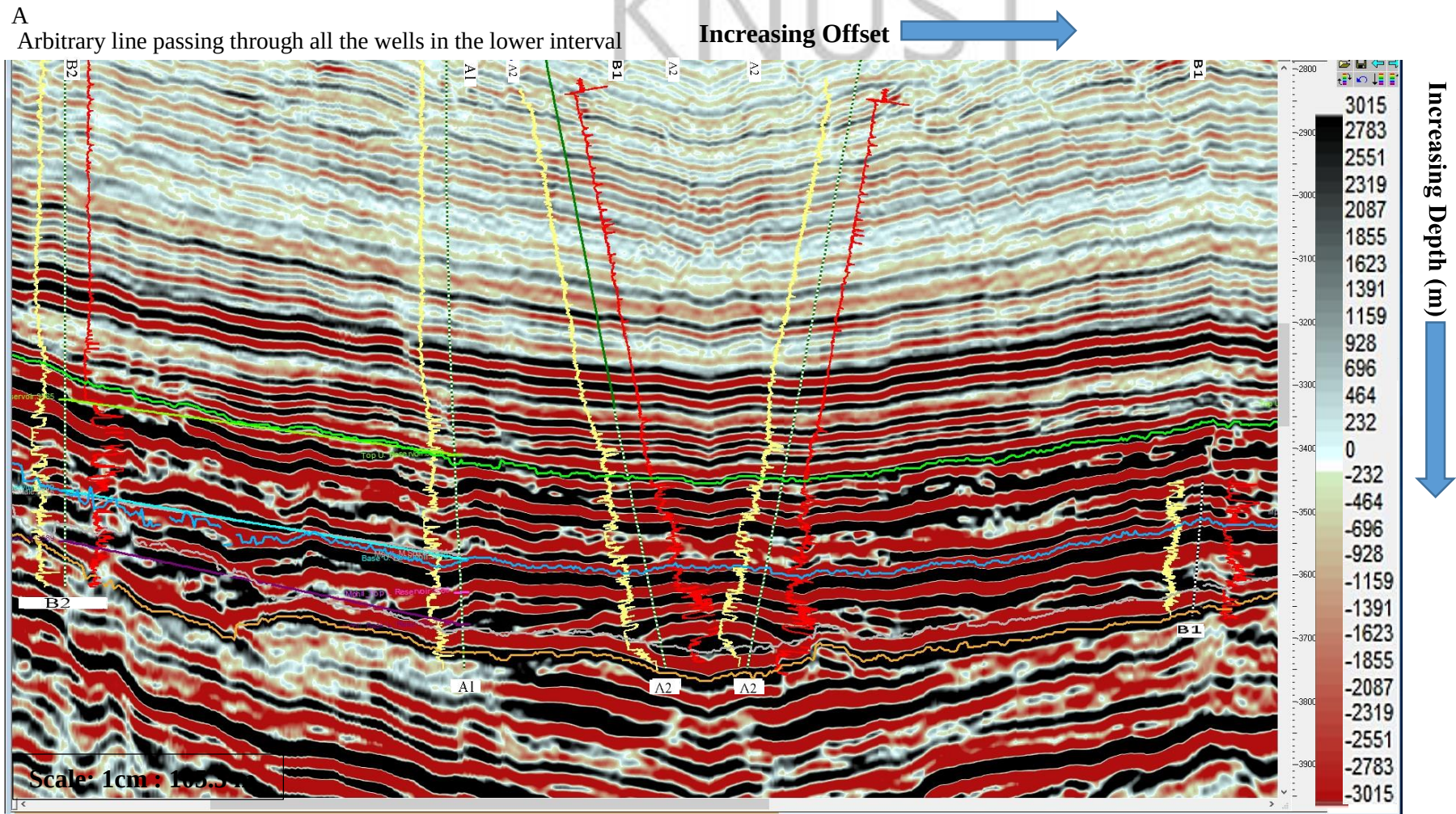


Figure 4.55 Arbitrary line showing log behaviour within selected intervals of interest

This figure shows the log responses of wells A₁, A₂, B₁ and B₂. It was used to determine whether the areas containing the wells possibly contained hydrocarbon bearing clean sands, in order to facilitate the selection of polygons on areas containing the largest well log hydrocarbon indicators.

.8.2 Structure Maps

4.8.2.1 Upper Interval

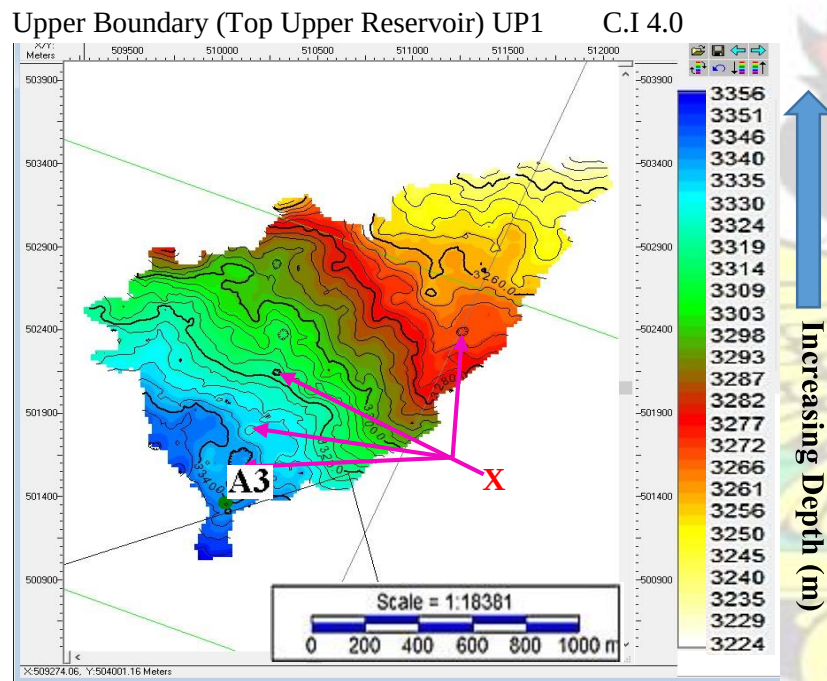


Figure 4.56 Contoured structure map of UP1

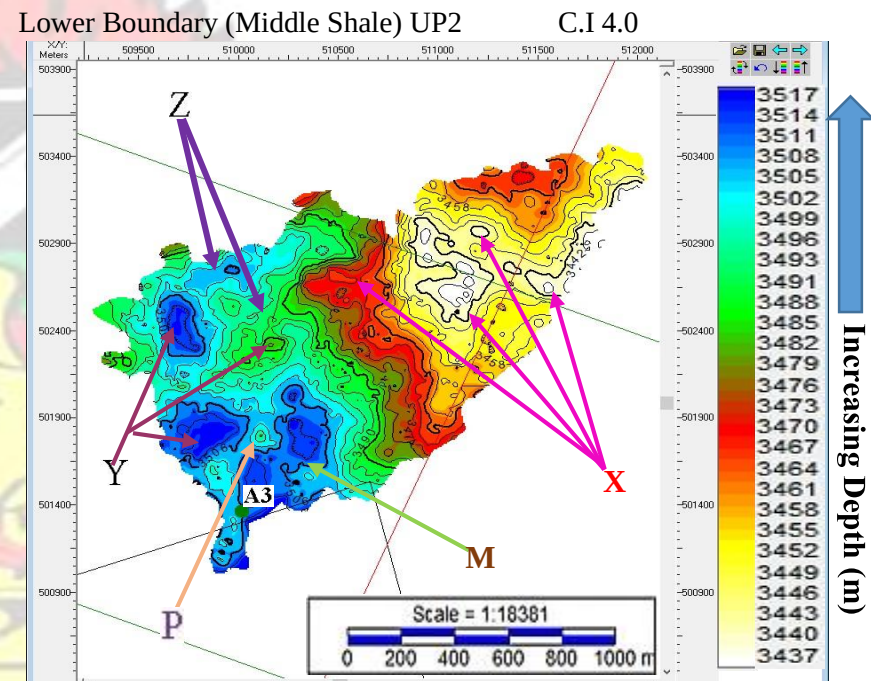
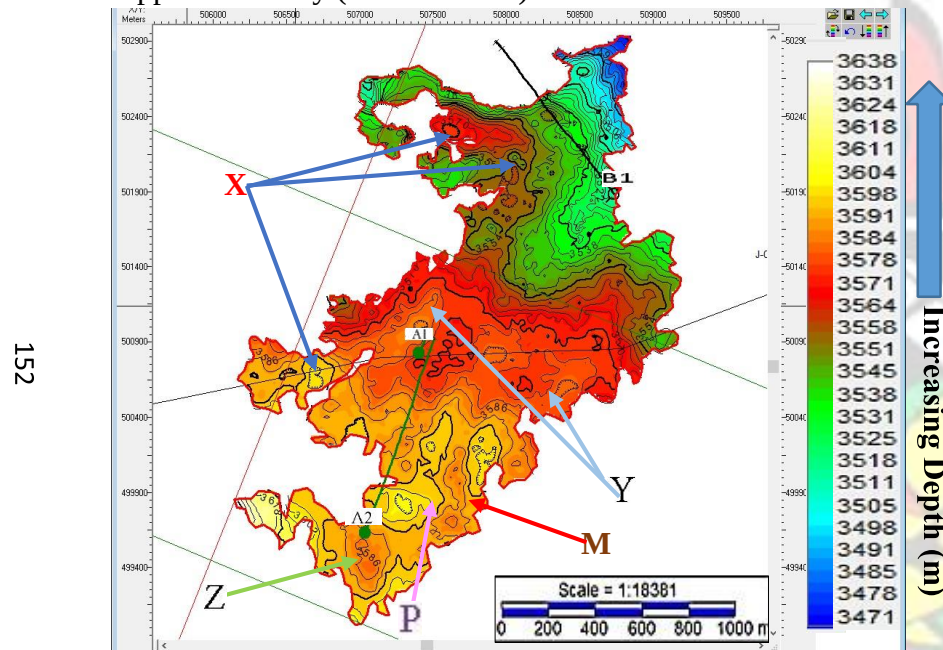


Figure 4.57 Contoured structure map of UP2

4.8.2.2 Lower Interval

Upper Boundary (Middle Shale) LP1 C.I 4.0

Lower Boundary (Base of Reservoir) LP2 C.I 4.0



The map above indicates a general trend of increasing depth in the down-dip direction in fairly even intervals of 4 m from 3229 m to 3356 m. This structure conforms with the depth variation trend on the structure map of the horizon from which it came. Several four-way closures which may serve as possible locations for the structural trapping of hydrocarbons are present on the map (X).

The depth variation trend is similar to UP1 with depth values increasing from 3437 m to 3517 m in the down-dip direction. The depth intervals are slightly larger here, possibly indicative of a more gradual declination in angle of dip. A greater number of four -way closures of larger sizes (X) are evident on the map, in addition to relatively large synclines (Y), three way closures (Z), an anticline (P), and a roll over syncline (M). The increased number of traps on UP2 suggests that the layer acts as a seal over the sand-trapping synclines, anticlines and closures in the lower reservoir interval.

Figure 4.58 Contoured structure map of LP1

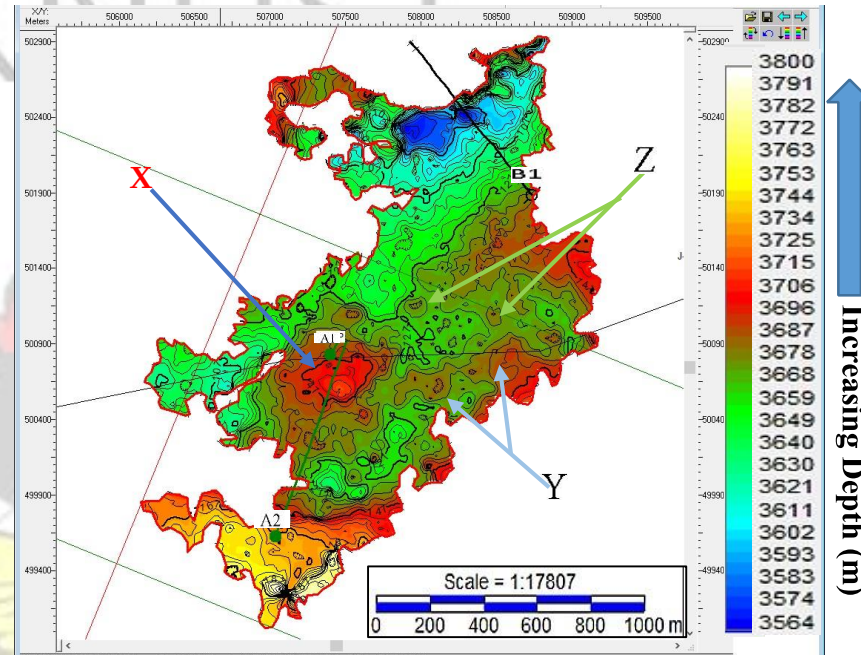


Figure 4.59 Contoured structure map of LP2

In the upper boundary of the lower interval, there is a repletion of the ‘increasing depth in dip-down direction’ trend. There appears to be a fair variation between the interval width of the various depth values suggesting a steep angle of dip inclination (at the top of the polygon), which gradually reduces in the south-western direction to give rise to a more gradual depth increment angle towards the base of the polygon. Several four-way closures (X), three-way closures (Y) an anticline (Z), a roll over anticline (M), and a roll over syncline (P) are identifiable on this map.

In the lower boundary, depth variation varies from place to place with deep structure (X) just below the center of the polygon. This depth trend difference from the other tre

layers could be as a result of the base not being picked at its exact location but rather slightly below it. Some of the structures reflected in this map may therefore emanate from below the base formation boundary. Several three (Y) and four-way closures (Z) are evident on this map.



4.8.3 Isochore Maps

4.8.3.1 Upper interval

C.I 2.0

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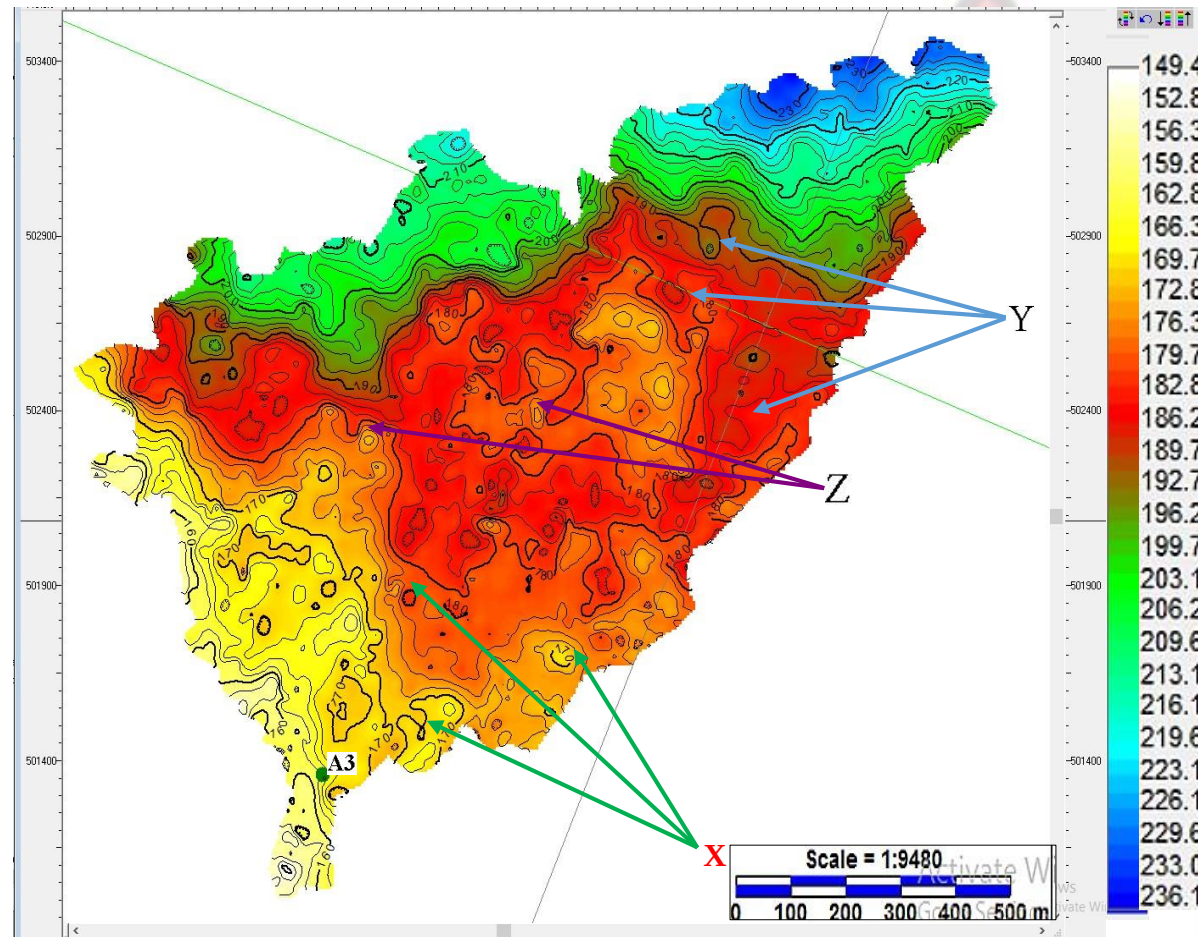


Figure 4.60 Thickness Map for the Upper Interval Polygon

The thickness map reveals increasing structural thickness with increasing distance south-east from 150 m to 236 m. a large number of four-way closures (X), a few three-way closures (Y), and anticlines (Z) are present in this Isochore map. This contour map is a reflection of what is occurring structurally between the upper and lower boundary of the polygon.

4.8.3.2 Lower interval

C.I 4.0

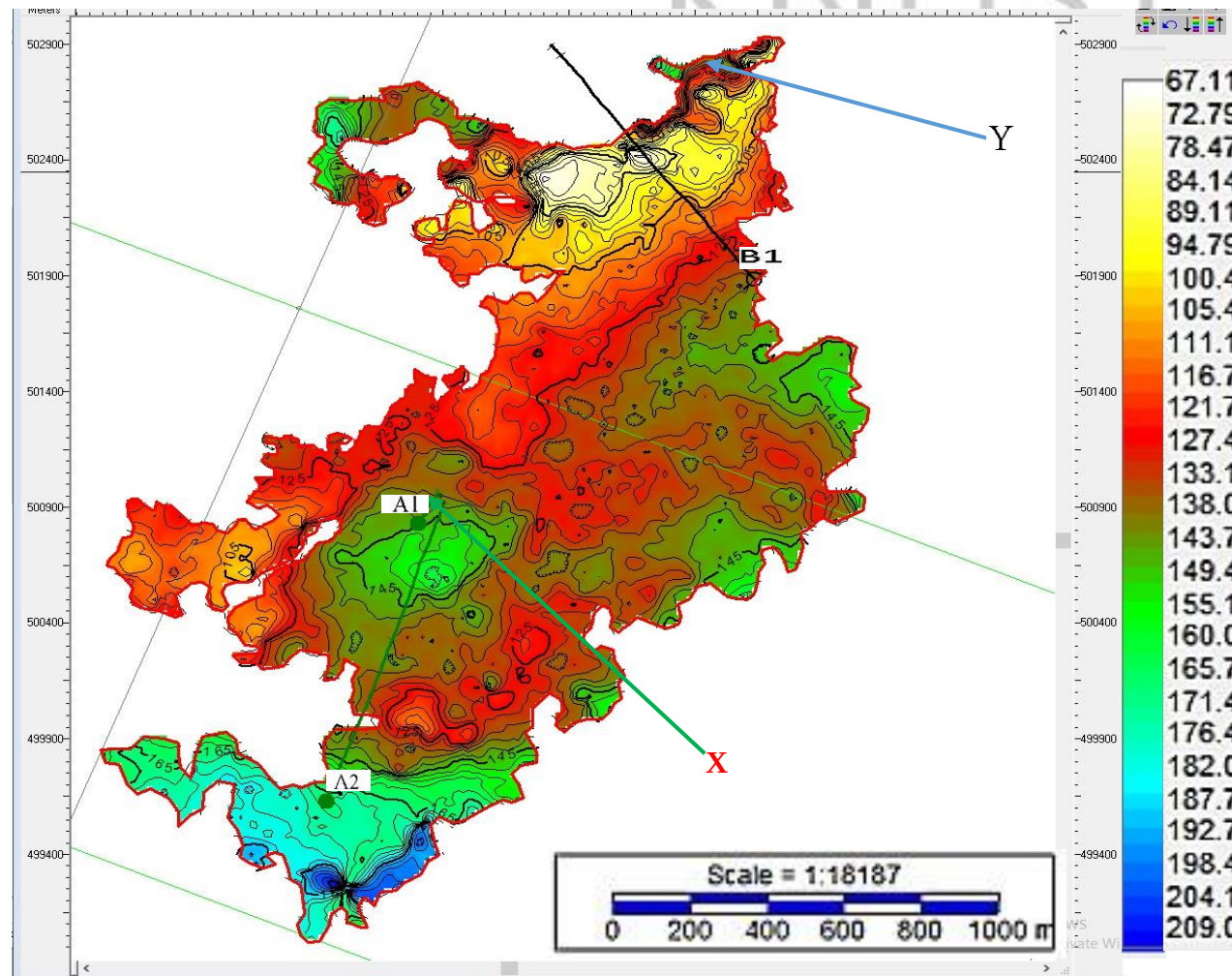


Fig 4.61 Thickness Map for the Lower Interval Polygon

The thickness map for the base looks more like the LP2, with the deep structure just below the center of the polygon (X), with a few deep zones (green colour) evident around the shallower yellow zones at the top. This suggests (Y) that the structure of the lower interval is fairly irregular and the reason could either be attributed to where the horizon was picked as explained in UP2, or could in actual fact be a true reflection (or approximately true reflection) of the structural behaviour of the lower reservoir interval.

4.9 PETROPHYSICAL PARAMETER CALCULATIONS

4.9.1 For Upper Interval Polygon (UP1)

4.9.1.1 Gross Rock Volume (GRV) Calculation

Depth scale 0.9 cm $\equiv$ 2 m

Polygon surface area = polygon size = 3,188,781.63 m²

Location of upper boundary of interval = 3,358 m

Location of lower boundary of interval = 3,529 m

Therefore,

$$\begin{aligned}\text{Apparent interval thickness} &= 3,529 \text{ m} - 2,258 \text{ m} \\ &= 171 \text{ m}\end{aligned}$$

But,

$$\begin{aligned}\text{GRV} &= \text{polygon surface area} \times \text{polygon thickness} \\ &= 3,188,781.63 \text{ m}^2 \times 171 \text{ m} \\ &= 545,281,658.73 \text{ m}^3\end{aligned}$$

Thus,

$$\text{GRV for UP1} = 545,281,658.73 \text{ m}^3 \text{ (or approximately } 545.282 \times 10^6 \text{ m}^3\text{)}$$

4.9.1.2 Gross Volume of Sand

Depth scale 0.9cm $\equiv$ 2 m

Therefore 1cm $\equiv$ 2.22 m

GR sand cut-off line = 50% (i.e. from 0-50 = clean sand)

Polygon area = polygon size = 3,188,781.63 m²

The results for the apparent sand and hydrocarbon interval thicknesses from the logs are displayed in Table 4.1.

Table 4.1 Apparent sand thicknesses (in cm)

Interval Position	Gross Sand Thickness	Only Hydrocarbon-Containing Sand Thicknesses
1	0.3	

2	0.35	
3	0.4	
4	0.35	
5	0.35	
6	0.2	
7	1.1	
8	1.1	1.1
9	0.3	
10	8.3	8.3
11	0.2	
12	0.5	
13	2.3	1.2
14	5.0	5.0
14	0.2	
16	5.0	4.0
17	0.3	
18	0.6	
19	1.4	0.4
20	1.9	0.7
21	0.3	
22	0.6	
Sum of all Intervals	31.05	20.7

Therefore,

Gross Sand Thickness = sum of all sand interval thicknesses (including those that contain hydrocarbons)

$$= (10.35+20.7) \text{ cm}$$

$$= 31.05 \times 22.2 \text{ m}$$

$$= 69 \text{ m}$$

Gross Volume of Sand = Gross Sand Thickness $\times$ Polygon Area

$$= 69 \text{ m} \times 3,188,781.63 \text{ m}^2$$

$$= 220,025,932.47 \text{ m}^3$$

Gross Volume of Sand = 220,025,932.47 m³ (or approximately 220.026 x10⁶ m³)

4.9.1.3 Net Volume of Sand

Net Sand Thickness = sum of all 'only hydrocarbon-containing sand' thicknesses

$$= 20.7 \text{ cm}$$

$$= 20.7 \times 22.2 \text{ m}$$

$$= 46 \text{ m}$$

Net Volume of Sand = Net Sand Thickness $\times$ Polygon Area

$$= 46 \text{ m} \times 3,188,781.63 \text{ m}^2$$

$$= 146,683,954.98 \text{ m}^3$$

Net Volume of Sand = 146,683,954.98 m³ (or approximately 146.684 x10⁶ m³)

4.9.1.4 Net to Gross Ratio

N/G = Net Volume of Sand / Gross Rock Volume (i.e. volume of polygon)

$$= 146,683,954.98 \text{ m}^3 / 545,281,658.73 \text{ m}^3$$

So Net to Gross Ratio = 0.269 = 26.9 %

4.9.1.5 Volume of Shale

$V_{sh} = GRV - \text{Net Volume of Sand,}$

N

But Net Volume of Sand = $\left(\frac{N}{G}\right) \times GRV$

$N \times GRV$

So $V_{sh} = GRV - \left(\frac{N \times GRV}{G}\right)$

N

$= \left(1 - \frac{N}{G}\right) \times GRV$

G

$$= (1 - 0.269) \times 545,281,658.73 \text{ m}^3$$

So $V_{sh} = 398,597,703.751 \text{ m}^3$ (or approximately 398.598 x10⁶ m³)

4.9.1.6 Total Average Porosity

Neutron Porosity Log scale 10 box widths = 0.6 p.u.

Therefore 1 box width = 0.006 p.u.

Table 4.2 Average porosity values

Porous Sand Interval Position	Interval Porosity Reading (p.u)
8	0.21
10	0.21
13	0.228
14	0.222
17	0.222
20	0.186
21	0.214
Total Porosity Reading for the 7 Intervals	1.49

Sum(Average Porosity Value)

$$\text{So average porosity reading} = \frac{\text{number of intervals}}{1.49}$$

$$= \frac{1.49}{7}$$

$$\emptyset = \text{Average Porosity} = 0.21286 \text{ p.u., or } 21.2 \%$$

4.9.1.7 Formation Resistivity

$$\text{From: } F = \emptyset^{\frac{a}{m}},$$

Where: $a = 0.81$ (Source, GNPC)

$m = 2$ (constant)

$$\emptyset = 0.212,$$

$$F = \frac{0.81}{212857^2} = 0.$$

So Formation Resistivity Factor = 17.8776 (or approximately 17.88)

4.9.1.8 Water Saturation

From:

$$S_w = \sqrt[n]{\frac{a}{m} \times R_{Rt}^{w_t}}$$

$$S_{wn} = FRR_{tw}$$

Where: $R_t = 500 \text{ ohm.m}$ (Source, GNPC)

$R_w = 0.389 \text{ ohm.m}$ at 77° F (Source, GNPC)

$$n = 2 \quad a = 0.81 \quad m = 2$$

$$S_w = \sqrt[2]{\frac{0.389}{0.81} \times \frac{17.87757}{500}}$$

So **Water Saturation** = **0.1179** (i.e. 11.79% of the pore spaces contain water)

4.9.1.9 Bulk Volume of Water

$$BVW = S_w \times \phi$$

$$= 0.1179 \times 0.212$$

So **Bulk Volume of Water** = **0.0250** (i.e. 2.5% of the gross rock volume is made up of water)

4.9.1.10 Hydrocarbon Saturation

$$S_H = S_o = (1 - S_w)$$

$$= (1 - 0.1179)$$

So **Oil Saturation** = **0.8689** (i.e. 86.89% of the pore spaces is saturated with oil)

4.9.1.11 Permeability

$$K = [250 \times (\frac{\phi^3}{S_w})]^2$$

$$= [250 \times (\frac{0.212^3}{0.1179})]^2$$

So Permeability = 408.19 mD

4.9.1.12 Original Oil in Place

From:

$$\frac{GRV \times \frac{N}{OOIP} \times \phi \times S}{1} = \frac{G_o}{B_o}$$

Where: $B_o = 1.65$ (Source, GNPC) ,

$$OOIP = \frac{545,281,658.73 \times 0.269 \times 0.212 \times 0.8821}{1.65}$$

$$= 16,624,282 \text{ m}^3$$

Converting it to standard units by multiplying by the conversion factor 6.29,

$$OOIP = 16,624,282 \text{ m}^3 \times 0.269$$

So Original Oil in Place = 104,566,736.5 bbl/STB (or approximately 104.567×10^6 bbl/STB)

4.9.2 For Lower Interval Polygon (LP2)

4.9.2.1 Gross Rock Volume Calculation

Using the same procedure as for UP1, with

Polygon area = $5,107,747.361 \text{ m}^2$

Average interval thickness = 138 m,

$$GRV = 704,869,135.81 \text{ m}^3$$

So,

GRV for LP2 = $704,869,135.82 \text{ m}^3$ (or approximately $704.869 \times 10^6 \text{ m}^3$)

4.9.2.2 Net Volume of Sand

Using the same procedure as for UP1, with:

GR Log scale 1cm $\equiv$ 2.22 m

GR sand cut-off line = 50% (i.e. from 0 - 50 = clean sand)

Polygon area = 5107747.361 m²

Average interval thickness = 138 m

The Net Volume of Sand = 532,881,067 m³ (or approximately 532.881 x10⁶ m³)

4.9.2.3 Net to Gross Ratio

Following the same procedure as for the upper interval polygon,

$$N/G = \text{Net Volume of Sand} / \text{Gross Rock Volume}$$

$$= 532,881,067 \text{ m}^3 / 704,869,135.82 \text{ m}^3$$

$$\text{So Net to Gross Ratio} = 0.756 = 75.6 \%$$

4.9.2.4 Volume of Shale

$$V_{sh} = \text{GRV} - \text{Net Volume of Sand},$$

$$= 704,869,135.82 \text{ m}^3 - 532,881,067 \text{ m}^3$$

$$\text{So } V_{sh} = 171,988,068.82 \text{ m}^3 \text{ (or approximately } 171.988 \times 10^6 \text{ m}^3)$$

4.9.2.5 Total Average Porosity

Neutron Porosity Log scale 10 box widths = 0.6 p.u.

Therefore 1 box width = 0.006 p.u.

Following the same procedure as for the upper interval polygon,

$$\frac{\text{Sum(Average Porosity Value)}}{\text{number of intervals}} \text{ average porosity reading} =$$

$$\text{So Average Porosity} = 0.20 \text{ p.u., or } 20\%$$

4.9.2.6 Formation Resistivity

$$\text{From: } F = \frac{a}{\phi} m ,$$

Where: $a = 0.81$

$$m = 2$$

$$\phi = 0.20$$

$$F = \frac{0.81}{0.20^2}$$

So **Formation Resistivity Factor = 20.25**

4.9.2.7 Water Saturation

$$\text{From: } S_w = \sqrt[n]{\frac{F R_t}{a m}} \times R_{wt} ,$$

$$S_{wn} = F R R_{tw}$$

Where: $R_t = 360 \text{ ohm.m}$ (Source, GNPC) R_w

$= 0.389$ at 77°F (Source, GNPC) n

$$= 2 \quad a = 0.81 \quad m = 2 ,$$

$$S_w = \sqrt{\frac{20.25 \times 0.389}{360}}$$

So **Water Saturation = 0.1479** (i.e. 14.8 % of the pore spaces contain water)

4.9.2.8 Bulk Volume of Water

$$BVW = S_w \times \emptyset$$

$$= 0.1479 \times 0.20$$

So **Bulk Volume of Water** = **0.0296** (i.e. 2.96 % of the gross rock volume is made up of water)

4.9.2.9 Hydrocarbon Saturation

$$S_H = S_o = (1 - S_w)$$

$$= (1 - 0.1479)$$

So **Oil Saturation** = **0.8521** (i.e. 85.21 % of the pore spaces is saturated with oil)

4.9.2.10 Permeability

$$K = [250 \times (\frac{\emptyset^3}{S_w})]^2$$

$$= [250 \times \frac{0.20^3}{0.1479}]^2$$

So **Permeability** = **182.9 mD**

4.9.2.11 Original Oil in Place

From:

$$OOIP = \frac{GRV \times \frac{N}{G} \times \emptyset \times S_o}{B_o}$$

Where: $B_o = 1.472$

$$OOIP = \frac{704,869,135.82 \times 0.756 \times 0.20 \times 0.8521}{1.472}$$

$$= 61,694,015.88 \text{ m}^3$$

This value is multiplied by 6.29 to convert it to standard units of bbl/STB (stock stand barrel at surface conditions). Thus,

So Original Oil in Place = 388,055,359.9 bbl/STB (or approximately 388.055 x10⁶ bbl/STB)

4.10 OVERALL INTERPRETATION OF RESULTS

Seismic facies are capable of predicting lithology. Using the European convention, the sands were represented by the peaks and the shales by the troughs. Due to seismic resolution, the maps could not identify every single stratigraphic and structural fault, as the software was not able to independently resolve all the depths from the seismic data provided.

From the GR logs on the seismic sections, most of the intervals which are dominant in sand packages appeared to be potential sources for hydrocarbon accumulation. This was confirmed with positively high resistivity log curve deflections.

From the Structure maps, a general trend of a downward increase in depth in the downdip direction was observed on all the horizons. There was a slight variation in the structure of the seabed which contained submarine ridges and canyons that formed finger-like depressions in the surface of the structure. These ridges serve as conduits, bringing the sand-sized sediments from the continental margins into the deep sea, with some sediments being deposited onto the canyon surfaces.

The contour maps described the horizon structures in a more detailed manner, facilitating the visual identification of structural trends and the structural traps that were captured by the contour interval range within which they fell. From them it was observed that the reservoir has thicker sediments at the base, which means that the sediment migration originated from the top of the study area, and proceeded downwards in the down-dip direction. There it was deviated by an elevated structure

called the Tano Nose. Several four-way closures and two anticlines were identified on the Seabed's contour map, and this interpretation was confirmed by the corresponding anticline peaks on the 3D structure map.

The Top Upper, Middle Shale and Base of the Reservoir horizons all displayed very similar structural characteristics with minute variations. All were however affected by the Tano Nose structure whose presence was only confirmed with the aid of the amplitude maps. The similarity between the three horizon structures gave an indication that the stratigraphic factors which affected the Base of the reservoir equally affected the Middle Shale and Top of the Reservoir.

In the amplitude maps of the horizon tops, a clear distinct depositional path (from the top left corner of the map to the center of the map) was identified in the Top Upper Reservoir. The middle shale layer had a very large volume of shale which originated from the same source as the sands, migrated and was broadly deposited in the middle and base portions of the survey area. In the Middle Shale map, the amplitude responses were more negative and decreased with an increasing shale content. This is because higher amplitudes are indicative of sands and therefore the reverse is true for shales. The base showed a very scattered pattern of sand distribution, which might be attributed to the fact that the Base horizon was not picked at its exact location (indicated on the formation top location on the wells), but was rather made to pass as closely as possible to it, where the reflection continuity was significantly improved. This introduced more shales into the data and therefore gave a slightly different output. No definite geologic bodies could be mapped out because of the fairway fan system of deposition, in which the sands were relatively spread out (or fanned out) across the surface away from the source.

In the faults interpretation section, a number of north west- south east trending cross faults in addition to east-west trending cross faults were mapped. Several first order and second order faults such as normal and reverse faults, unconformities, roll over anticlines, growth faults and low stand wedges were identified on the map. Uplift and erosion contributed to the poor amplitude responses seen on the inlines and crosslines located near the top of the survey area.

In the volumetric attribute calculations, the attribute that best described this reservoir was selected by comparing the image results for *vatmin*, *vatmax* and *vatrms* attributes, as well as determining whether the nears data gave better images than the fars. It was concluded from the results that the *vatrms* in the fars best described the reservoir sands in the depth- volume data. The distinctively different architectural elements for the different intervals proved that the sand packages were deposited at different locations at different depth levels. The EEI volumetric extractions however did not produce good results as the area was not structurally confined, the trapping systems were not large enough to be detected by the inversion, and there were no definite geologic bodies along which the sands could be deposited- since the EEI inversion analyses and quantifies every individual sand-like response, and the sand distribution in the area is scattered and varies in amplitude from point to point. The EEI conditioned to lithology could therefore not be used to identify the exact locations of the clean sands for further petrophysical analysis.

The *vatrms* intervals selected from the depth data for petrophysical calculations led to the assumption that the lower interval had a greater concentration of sand packages and consequently hydrocarbons around well B3, than the Upper interval (near well A2). The high gamma ray kicks to the left with corresponding curve deflections to the

right cemented this assumption. Full confirmation was however only achieved with petrophysical calculation results.

From the logs it was assumed that the upper reservoir unit displays a sheet-like stacking pattern of sands and shales, meaning there are thin beds of sands in relatively thick sections of shale in a sand-shale cyclic repetition pattern. With the low porosity values and a more than doubled volume of shale in the upper interval, this assumption was confirmed. The results of the petrophysical calculations have been summarized in table 4.1 below.

Table 4. 3 Summary of petrophysical results

Petrophysical Properties	UP1	LP2
Gross Rock Volume (m ³)	545,282 x10 ⁶	704.869 x10 ⁶
Net Sand Volume (m ³)	146.684 x10 ⁶	532.881 x10 ⁶
Net/Gross Ratio (%)	26.9	75.6
Volume of Shale (m ³)	398.598 x10 ⁶	171.988 x10 ⁶
Total Average Porosity (%)	21.2	20.0
Formation Resistivity Factor	17.88	20.25
Water Saturation (%)	11.79	14.79
Bulk Volume of Water (%)	2.50	2.96
Hydrocarbon Saturation (%)	88.21	85.21
Permeability (mD)	408.19	182.90
Original Oil in place (bbl/STB)	104.567 x10 ⁶	388.055 x10 ⁶

In summary, the entire reservoir can be divided into an upper and lower unit (between the Top Upper and Middle Shale, and the Middle Shale and Base horizons respectively). The former shows a characteristic where the shale beds are thicker, whereas in the latter, a reversed situation is the case. As expected, the fine-grained shales contain very high porosities. Because the pores and pore throats within these

formations are so small however, they exhibit little or no permeability, and thus serve as a seal for the underlying sandstone reservoir. The lower interval contains sandstone sequences which exhibit high permeability, and hence serve as optimum locations for oil accumulation. Generally, the porosity/permeability values of the sandstone reservoirs are good enough to accommodate a large hydrocarbon yield, and this characteristic tends to improve significantly as sedimentation proceeds basin-wards.

CHAPTER 5 CONCLUSION AND RECOMENDATIONS

Based on the above results, this reservoir can therefore be predicted to have been deposited in the form of a fairway fan system which is divided into an upper and lower interval by a thick middle shale layer that acts as a plug, sealing the hydrocarbon bearing traps below.

Analysis of the seismic data revealed three horizons (Top Upper, Middle Shale and Base of Reservoir) which display general structural trends of increasing depth with increasing distance south-west from the reservoir source (in the down-dip direction). The trapping system is mostly structural- consisting of three and four-way closures, anticlines, synclines, and roll along anticlines and synclines. The first research objective has thus been attained.

From volumetric attribute mapping, it was determined that the best attribute for extracting the architectural elements from this reservoir was the *vatrms* in the fars. This attribute proved useful in describing the demographic distribution of the sand packages and gave an idea as to the location of the reservoir source, and the direction of sediment migration. A large elevated structure (called the Tano Nose) which had a deviating effect on the migration path of the sediments was also observed with the aid of the attribute maps. The fact that the attribute maps generated the architectural elements (which can be likened to the shape of the reservoir unit) -that enabled the

selection of digitized polygons containing hydrocarbon-bearing sands for petrophysical analysis- achieved what the EEI inversion could not (due to the unlocalised concentration of the deposited sands and lack of definite geological bodies) proves how important attribute mapping is to reservoir characterisation. The second and third objectives have thus been attained.

With the aid of the logs, the petrophysical calculations yielded good values of porosity (21.2 & 20 %), permeability (408.2 & 182.9 mD), oil saturation (88.2 & 85.2 %), and original oil in place ($104.567 \text{ \& } 388.055 \times 10^6 \text{ bbl/STB}$), for the upper and lower polygons respectively. In comparing the results from both polygons, it became evident that even though the lower reservoir had lower oil saturation and permeability in addition to its greater BVW, it contained more hydrocarbons (as a result of its greater N/G ratio and lower volume of shale) with good porosity and permeability properties. This could be attributed to the fact that it was effectively sealed by the middle shale plug, thus allowing time for sufficient hydrocarbon generation and accumulation. The fourth and final objective has thus been attained.

Overall, this technique has proven successful in predicting reservoir properties in an efficient and cost effective way through the integration of three types of data for the enhancement of the vertical resolution, quality and accuracy of the results. It is therefore recommended in reservoir characterisation of oil fields in the middle and late developmental stage.

It is however recommended that further research using AVO be done on the regions that displayed relatively high amplitude responses over a wide area but could not be investigated in this study due to the lack of well log data for those areas.

Study area should be investigated using Extended elastic impedance data conditioned to fluids to confirm results

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