EVALUATION OF HYDROCARBON RESERVE IN AD FIELD, OFFSHORE NIGER DELTA

BY

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CERTIFICATION

This is to certify that this work was carried out by Moyosoluwa Odunayo ADEYEMI, in the Department of Geology, University of Ibadan under my supervision.

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DEDICATION

*I dedicated this work to **The Almighty God** for being my Source, Sufficiency and Sustenance throughout the course of the program.*

*Also with excitement and a deep sense of appreciation to my wife, **Mrs Adebukola Omoyele Adeyemi**and two sons**Jedidiah and Jacob Adeyemi** for their support and prayers*

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GLOSSARY OF TERMS

a: Archie/Tortuosity factor

FVF: Formation Volume Factor.

GIIP: Gas-initially-in-place

GOC: Gas Oil Contact

Gross Int.: Gross interval

GRV: Gross Rock volume

HCPV: Hydrocarbon pore volume

HIIP: Hydrocarbon-initially-in-place

m: Cementation factor

MMbbl: Million barrels

n: Saturation factor

Net Res: Net reservoir thickness

NTG: Net to Gross ratio

ODT: Oil Down To

OHIP: Original hydrocarbon-in-place

OUT: Oil up To

OWC: Oil Water Contact

RB: Reserved Barrels

Rt: True resistivity from log

Rw: Water resistivity

STB: Stock Tank barrels

STOIIP: Stock-tank-oil-originally-in-place

TCF: Trillion cubic feet

Φ: Porosity

$\boldsymbol{Sh}$**:** hydrocarbon saturation

$\boldsymbol{Sw}$**:** water saturation

$\boldsymbol{Swe}$:Effective shale corrected water saturation

$\boldsymbol{Vsh}$:. Volumetric fraction of shale

ABSTRACT

Exploration and production activities in the oil industry involve huge financial resources and in order to reduce associated economic risks, adequate uncertainty quantification and reserve evaluation are required. This study was carried out to quantify the uncertainty in the reserve estimate of hydrocarbon in the reservoirs of AD Field, offshore, Niger Delta.

Three Dimensional (3D) seismic data, log suites from seven wells (AD1 to AD7), consisting of gamma ray, resistivity, neutron and bulk density logs, well deviation and checkshot data in AD Field were acquired from oil producing companies in the area. Faults and horizons were identified and picked across the 3D seismic record for structural horizon. The gamma ray log was used to delineate the reservoirs while neutron and bulk density logs were used to identify the fluid contacts. Seismic and well data were tied after which seismic reflections corresponding with the reservoirs' surfaces were picked across the seismic volume. Static models were generated using the identified seismic structure, lithofacies and petrophysical information. Monte Carlo Simulation for stochastic was carried out to evaluate the reserve estimates.

Twelve faults (Fault1 to Fault12) were identified from seismic structural interpretation. The faults were predominantly elongate listric normal growth faults trending from East to West. Fault2 and Fault3 were identified as the regional faults with roll-over anticlines responsible for hydrocarbon trapping. Six hydrocarbon-bearing sand intervals (Sand A - F) were delineated from the petrophysical analysis. The sand intervals were observed to thin-out basin wards, suggesting a prograding sequence. The facies model indicated that the reservoirs were predominantly coarse sands with shales, which were deposited in a North-South orientation, signifying a transgressive marine with minor influence of tide. The porosity of the sand intervals ranges between 0.19 and 0.32, implying good to excellent porosity. The water saturation values ranged from 0.19 to 0.39, indicative of prospective accumulation of hydrocarbon. Sand A reservoir had the largest accumulation of hydrocarbon in-place with hydrocarbon pore volume of 2,343 106 RB, Stock Tank Oil-Initially-In-Place (STOIIP) of 175 MMbbl and gas initially-in-place of 0.30 TCF. The stochastic reserve estimates of the field showed that P10, P50 and P90 for the STOIIP were 482 MMbbl, 554 MMbbl and 636 MMbbl respectively. The coefficient of variation in the reserve estimates of the reservoirs ranged from 0.09 to 0.15 indicating very low uncertainty. Sensitivity analysis based on Monte Carlo simulation showed that porosity, gross rock volume, net to gross and saturation have an increasing order effect on the reserve estimate of the sand intervals which have a low coefficient of variation ranges from 9% and 14% suggesting that the uncertainty of the values are low.

The derived uncertainty from the AD Field was low indicating substantial accumulation of hydrocarbon reserve that could be exploited.

CHAPTER ONE

1.0 Introduction

1.1 General Statement

The Niger Delta basin is in the Gulf of Guinea and it is one of the major delta systems in the world that is Tertiary in age, its sediments covers an area of approximately 75,000 km^2 and progrades southwest from Eocene to the present, forming different depobelts (Nwajide, 2013). The basin rank (12th) among the best prolific petroleum belts world over and it is Africa's biggest and most prolific oil generating basin (Tuttle *et al*., 1999). The Niger Delta accounts for 2 to 5% of the present-day sedimentary basins on earth with hydrocarbon reserve above 34.5 billion barrels (STB) of oil and 93.8 trillion cubic feet (TCF) of recoverable gas (Reijers *et al*., 1996).

Seismic and well log information play key roles in hydrocarbon reserve evaluation (Egbai *et al.,* 2012). The commercial prospect evaluation of hydrocarbon reservoirs often begins with exploration, through development and ends with the exploitation. Three-dimensional seismic interpretation and petrophysicalanalysis were integrated to give information on the reservoir characterization of oil fields for economic viability and cost effectiveness. Geological concepts and reservoir characteristics hused in the evaluation of hydrocarbon reserves are often full of uncertaintyregardinggeological structures, hydrocarbon seals, and hydrocarbon charge. The use of practical methods for estimating the uncertainties associated with the geology of reservoirs without compromising accuracy is of utmost importance in reservoir evaluation and field development programs (Odai and Ogbe, 2010).

1.2 Location of the Field

The AD Field is about 94 km offshore Niger Delta, Nigeria (Fig 1.1) and lies within one of the six major depobelts of the Niger Delta petroleum system. The acquisition of 3D data over this field has prompted the re-evaluation of the producing reservoirs. The field was owned by Chevron and an appraisal of the field has been carried out with the drilling of seven wells but a full-scale development wasn't carried out before the field was sold to an indigenous oil and Gas Company in 2013. The indigenous company plans to commence full field development soonest.

1.3 Aim and Objectives

The principal aim of this work is to adequately evaluate the hydrocarbon reserve in the AD Field, Niger Delta Basin and the specific objectives are to:

i. characterize the reservoirs in the field using both geological and petrophysical analysis.
ii. identify and correlate hydrocarbon bearing-sand intervals across the field.
iii. generate property models such as facie model, porosity models and water saturation model which will be used for volumetric modelling.
iv. conduct a probabilistic analysis of the volumes-in-place.
v. assess the uncertain parameters observed during the development of geological models.

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Figure 1.1 Location of the Study Area

1.4 Expected Contribution to Knowledge

This research will provide information that will give an understanding of the reservoir geometry and properties of the field. The understanding of the reserve will further reduce the uncertainties attached to the subsurface reservoirs during the assessment of the hydrocarbon reserves. The 3D static model produced from this study will enable optimal well placement during production of the field.

1.5 Literature Review on Niger Delta Basin

From early publications on the post-Cretaceous stratigraphy of southern Nigeria by Parkinson, (1907) to the substantial amount of publications on public domains, several published and unpublished researches have been made available on the basin. The geology of the basin and the methods for evaluating hydrocarbon resource have been widely studied because of their economic importance and some of the findings are discussed below: Short and Stauble (1967) classified the Tertiary fill into Akata, Agbada and Benin Formations. Hack *et al* (2000) identified three (3) Petroleum systems in the Niger Delta basin namely the Lacustrine Petroleum system (lower Cretaceous) identified in the NW part of the Delta, it probably forms a fragment of the Benue trough; the marine Petroleum system(Lower Paleocene - Upper Cretaceous) and the Tertiary deltaic Petroleum systems which is a major source of hydrocarbon.Ozumba *et al*(2005) reported the accumulation of hydrocarbon in the Niger Delta to be as a result of the combination of both structural and stratigraphic traps.

Reservoir characterization have evolved as a result of the integration of geology, geophysics, petrophysics, and geostatistics as a tool for providing better understanding of subsurface reservoirs and their homogeneities (Sessions and Lehman, 1989). Haldorsen and Lake (1984) together with several authors such as Begg and King (1985) have worked on the characterization and modelling of random shale. Several authors have also contributed to advancement in techniques used in quantifying the influence of uncertainties in reservoir modelling.Garb (1988) proposed the use of both deterministic and probabilistic techniques for hydrocarbon evaluation. Caldwell and Heather (1991) considered analogy, volumetrics and performance analysis as the three main categories for reservoir evaluation. Bueno *et al.,* (2011) applied this technology in static reservoir modelling as it affects volumetric estimation by identifying and quantifying the input properties (petrophysical parameters) having the greatest impact on the reservoir estimate.

1.6 Overview of Uncertainty Evaluation

Uncertainty denotes to the deficiency of assurance or improbability of a statement on the precision of a measurement (Olea, 1991; Ballin *et al.,* 1993). In the petroleum industry, the utmost concerns are matters of economic returns from actual reserve estimate of the hydrocarbon in place (Garb, 1988).Certainty of estimated reserve is often difficult. However, adequate reserve evaluation plays an important role in the decision-making process for exploration and production companies and their potential investors at the various stages of field development (Zhang, 2004).

In the petroleum industry, the probabilistic expressions of reserve estimates have been embraced (Lu and Zhang, 2003). Common methods for reserve estimation usually involve calculations with mathematical models which assigns a deterministic value for estimated reserves. These deterministic values do not take cognisance of the uncertainties associated with the estimations, it simply assigns the deterministic reserve estimates as the most likely value (Ferruh, 2007). Reserve predictions are never completely correct when the uncertainties associated with it are not taken into consideration. Thus, a statistical or probabilistic method would be more appropriate for a more precise prediction of reserve estimates.

Uncertainties associated with reserve estimation are sourced from factors such as: measurement errors, model errors, and inadequate data sets (Zhang, 2004). Measurements such as the production and pressure-volume-temperature data are often inaccurate as a consequence of poor tool calibrations or error from the handler. These errors are subject to the precision of the tools and cannot be eliminated. Uncertainties are often incurred when geoscientists and engineers evaluate reservoir parameters using various models. These models are not perfect because they depend solely from either experiments or on assumptions which are inappropriate in real circumstances. Finite-difference reservoir simulators are also subject to inappropriate assumptions and computational errors. Complete data sets are never obtained thus reasonable guesses are often made using the available information at hand and experience and this process is responsible for contributing inaccuracies to the prediction.

Insufficient information during theassessment of an oil field, or inadequate description of the reservoir in the course of the developing the oil field can increase the risk connected with decision making. Uncertainty evaluation and risk assessment of reservoirs would enhance investment choices (Schiozer *et al*., 2005). Conversely, it is difficult to estimate these uncertainties as they require the knowledge of both static and dynamic performance during the production of the reservoirs (Lu and Zhang, 2003). Notwithstanding, both mature and producing fields can have uncertainties in the reservoir characterization which can result into financial losses (Capen, 1976; Garb, 1986).

Methods for analyzing uncertainties provide innovative and elaborate ways of weighing and comparing the risks and uncertainties associated with each decision making. Uncertainty analysis provides an insight into the probability of attaining different levels of profitability after investment. The advantage of uncertainty evaluation techniques is that it reduces the complexity and difficulty in measuring the degree of uncertainty (Garb, 1986).Some uncertainty analysis methods such as Monte Carlo Analysis also provide great techniques to assess the sensitivity of different variables related to general value. Analysis of uncertainty offers a means of comparing comparative desirability of numerous projects and serves as a clear manner of communicating risk and uncertainty decisions. Using methods for uncertainty analysis, extremely complicated investment alternatives can be analyzed. For economic development of reservoirs to maximize return, producers must identify and attempt to decrease the associated uncertainties if possible (Lu and Zhang, 2003).

1.6.1 Overview on Uncertainty Evaluation ofReserves

The application of both deterministic and probability (stochastic) methods for estimating hydrocarbon reserves was first introduced by Garb (1988). This method was classified into three (3) principal stages; analogy, volumetric and performance analyses by Masoudi *et al*. (2011). The suitability of the probabilistic method makes it more viable compared to the deterministic method when uncertainty is high (Caldwell and Heather, 1991). A petroleum classification scheme on the basis of reserve and risk assessment is presented in Figure 1.2. Uncertainties are associated with the estimation of hydrocarbons in a new or producing field (Akinwunmi *et al*., 2004) and they may relate to the structural framework of the geology of the field, extent of the hydrocarbon accumulation, delineation between the invisible contacts between water, oil and gas

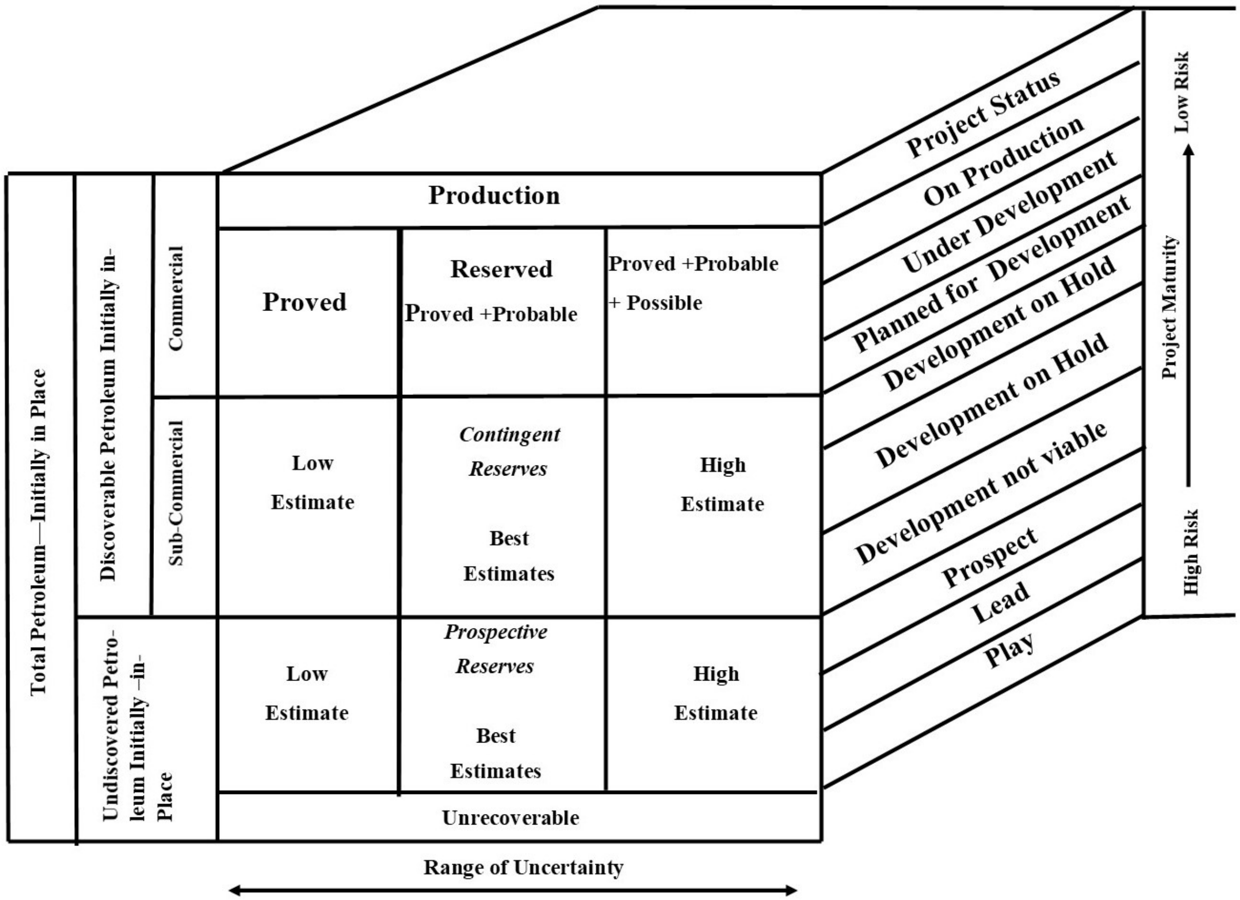

Figure 1.1Petroleum Resource Classification Scheme (SPE/WPC/AAPG, 2000)

showing the vertical magnitude, inner reservoir geometry, and the nature of the formation fluid(s).

In the oil and gas industries, discovery wells are often developed and producedbefore their structures can be critically appraised except, they are obliged to reconsider the appraisal of drilling and insist on generating from current wells. These factors have an effect on thereserve estimates and volume of hydrocarbons that can therefore be recovered. While developing and planning a field, it is a common practice to find and assess the effect and distribution of significant uncertainties in the reservoirswhich can affect the estimation of thereserves (Akinwumi *et al*., 2004). The lack of pressure-volume-temperature data and other information adds to the implausibility of fluid properties therefore increasing the risk and uncertainties associated with the reserve estimates.

1.6.2 Overview of Uncertainty in Evaluation of Volume of Gas in Place

Aprilla *et al*. (2006) used Bayesian analysis to determine the degree of uncertainty in the estimates of original gas in place. This interpretation has also been used to lessen ambiguity in the prediction of unknown reservoir parameters while simulating an oil field by Fathe *et al*. (2010). Galli *et al*. (2004) used the different scenarios for the exploration of a gas field. Firstly, they used the Bayesian interpretation combined with volumetric and material balance techniques to compute the uncertainty of reserve estimates in a reservoir. Also, they evaluated the uncertainty of two (2) reservoir parameters using the Havlena Odeh material balance equation. This multidisciplinary approach and their outcomes attempt to translate uncertainties in reserve estimates into an array of in-place quantities for the purpose of developing the field(Akinwumi *et al*., 2004).

1.6.3 Limitations and Shortcomings of Some Existing Uncertainty Methods

The Bayesian method is notably suitable for post-data inference as it assigns probability to the range of the model. The theorem of Bayes offers an empirical basis for reviewing estimates of reservoir properties and their uncertainties at the preliminary stage when further data is made accessible. One significant limitation is that there may be need for sizeable amount of reservoir models before a suitable model is acquired that will match the production information. According to Zhang (2003), where the independent variables are random and incompatible, the Monte Carlo method may be quite computationally intensive. In order to acknowledge the variety of dependent variable response, a bigger amount of mathematical model runs may be required. In Monte Carlo method, the output distribution of dependent variables is susceptible to the distributions of input parameters. Probability density functions are required before the Monte Carlo method can be implemented to produce random numbers for independent variables.

The Monte Carlo method involves the use of statistical techniques; thus, a sound statistical understanding isneeded for its right implementation and interpretation of the outcomes. Furthermore, some subjectivity is involved in preliminary determination of the input variable distributions and the nature of the parameters. The Monte Carlo method is the best used method for risk analysis in the oil sector, project assessment and even fracture-characteristic inquiry (Peterson *et al*., 1995; Komlosi, 2001; Murtha, 1997; and Kokolis *et al*., 1999).

1.7 Statement of the Problems

Many oil field developments are ongoing in the Niger-Delta because several marginal fields have been assigned toindigenous investors. Be that as it may, it is necessary for investors to adequately evaluate the risks and uncertainties associated with the reserve estimates obtained from these field. Such findings will further assist the investors to identify the appropriate risks to be taken.

CHAPTER TWO

2.0 Regional Geological Setting and Basin Evolution

2.1 Regional Geological Setting of the Niger Delta Basin

The Tertiary Niger Delta is situated in the Gulf of Guinea off the coast of West Africa. The basin encompasses the entire Niger Delta with an area covering an expanse of about 1,200,000 square kilometres (km^2) (Klett *et al*., 1997).and it lies within the coordinates of latitudes, 3^o to 6^o N and longitudes, 5^o to 8^o E (Reijers *et al*., 1996). The basin is a product of sediments supply from rivers in the present-day Niger River, Benue River, Cross River and their several distributaries all flowing into the Ocean.Sediments deposited by the rivers and distributaries consist of unlithified sands and shales which produced the different formations that makes up the basin (Idowu *et al*.,1993). The Niger Delta sedimentsprograde southwest from Eocene to Recent had formed depobelts which are the most active portion of the delta at thestage of every growth (Doust and Omatsola, 1990). The Niger Delta depobelts formed one of the world's biggest regressive deltas within a region of some 300,000 square kilometres, a sediment volume of 500,000 cubic kilometres with a sediment thickness of over 10 kilometres (Hospers, 1965, Kulke, 1995, Kaplan *et al*, 1994).

The basin can be divided into three diachronous lithostratigraphic unit based on their stratigraphy, sedimentological, faunal data and their age relation. The units are Akata, Agbada and Benin Formations from bottom (oldest) to the top (youngest) formation (Short and Stuable, 1967; Weber and Daukoru, 1975).The Akata Formation comprises of predominantlymarine shales, with sandy and silty beds which occur as turbidites and continental slope channel fills. The Agbada Formation predominantly consists of shoreface and channel sands at the top and an intercalation of sands and

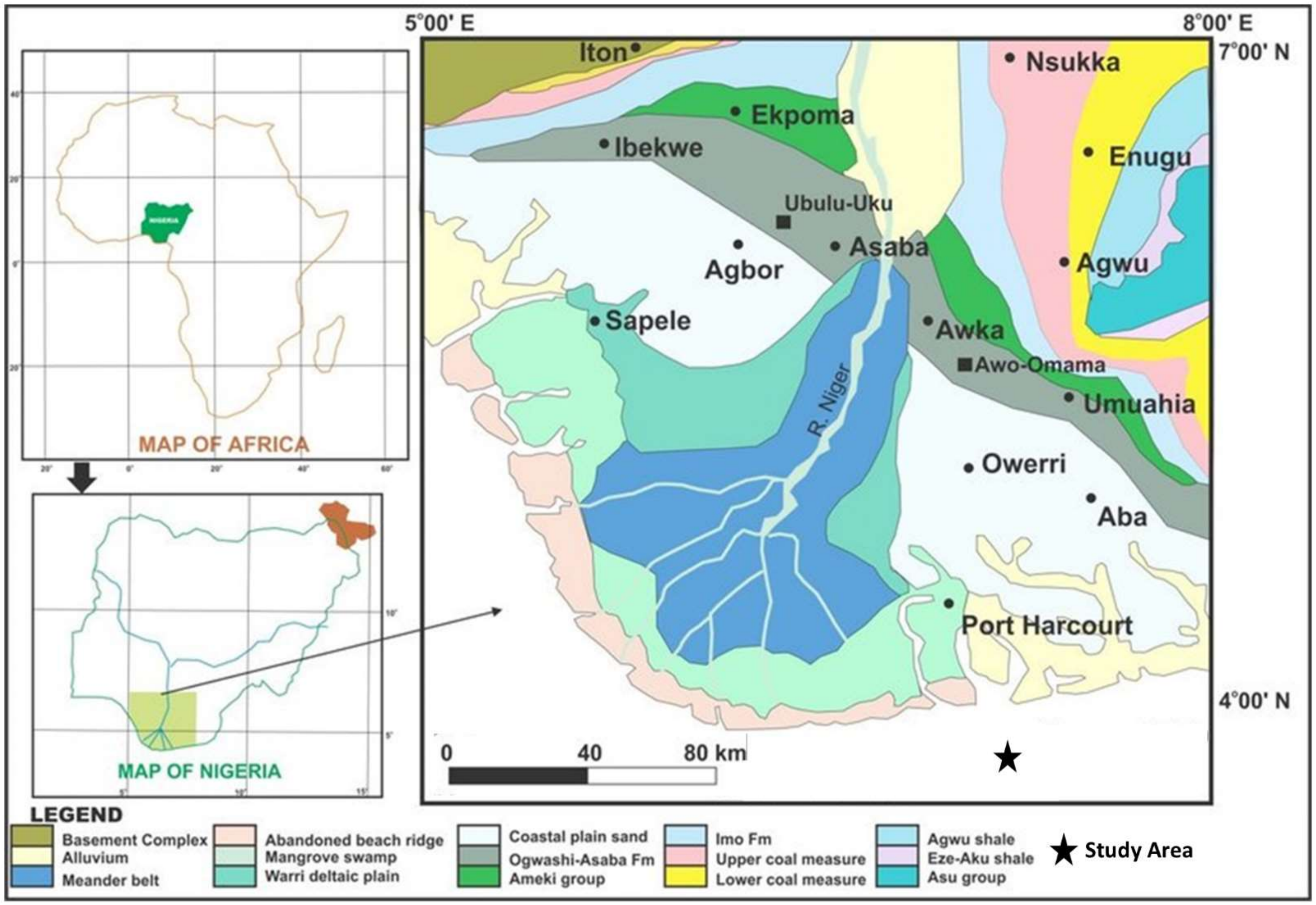

Figure 2.1 Map of the Niger Delta basin (After Nwanjide, 2013)

shales of equal proportion in the bottom. The Benin Formation predominantly consists of about 90% of sands and gravels from the continent with little shale intercalations, which becomes more abundant towards the bottom. The Akata Formation is made up of marine sediments predominantly shales with sandstone intercalations. The formation has been recognized as the major source rock for Niger Delta (Evamy *et al*, 1978).

The basin is one of the most productive hydrocarbon provinces globally. The Akata and Agbada Formations (Tertiary) are the most prominent petroleum system in the basin (Kulke, 1995; Ekweozor and Daukoru, 1994). The petroleum system has hydrocarbon reserves of about 34.5 billion barrels of oil and 93.8 trillion cubic feet of gas which ranks 12^{th} richest in hydrocarbon resources world over with 2.2% of oil and 1.4% of gas reserves (Petroconsultant, Inc., 1996).

Most of the petroleum fields in the Niger Delta are either on the continental shelf with depth of about 200 meters with relatively simple but immense geological structures or onshore. The trapping mechanisms for hydrocarbon accumulation in the Niger Delta are predominantly found in roll over anticlinal traps present in the Agbada Formation. The prodeltaic shales in the eastern part of the Niger Delta serves as active source rocks for the production of hydrocarbon while the shales in the central and western part have also contributed to hydrocarbon pooling (North, 1985).

2.2 Basin Evolution and Tectonic Setting

The evolution of Niger Delta basin is related to the episodes of rifting and drifting apart of the African and South American plates which led to the opening of the South Atlantic Ocean (Reijers *et al.,* 1996). The rifting started and continued from late Jurassic till mid Cretaceous and the episode diminished in Late -Cretaceous (Lehner and De Ruiter, 1977). After the Atlantic Mesozoic rift, sedimentation started with deposits of Albian drift. The Benue Trough was filled with sediments and during Late Eocene, the basin started prograding into the current continental slope down to the deep sea. The continued pro-gradation of marine deposits since the Eocene extended to the current continental margin.

Cretaceous fracture zones occurring as trenches and ridges in the abyssal plains of the Atlantic Ocean controls the structural framework of the Niger delta (Dim, 2016).The ridges subdivide the continental margin of the South Atlantic Ocean into separate basins, forming the Cretaceous Benue-Abakaliki trough's border faults and cutting far into the shield of West Africa. The trough is a detachedsegment of a triple rift intersection linked to the evolution of the South Atlantic Ocean. A schematic diagram of a Niger Delta axial segment illustrating the connection between Tertiary fills and the Cretaceous sediments are presented in Figure 2.2.

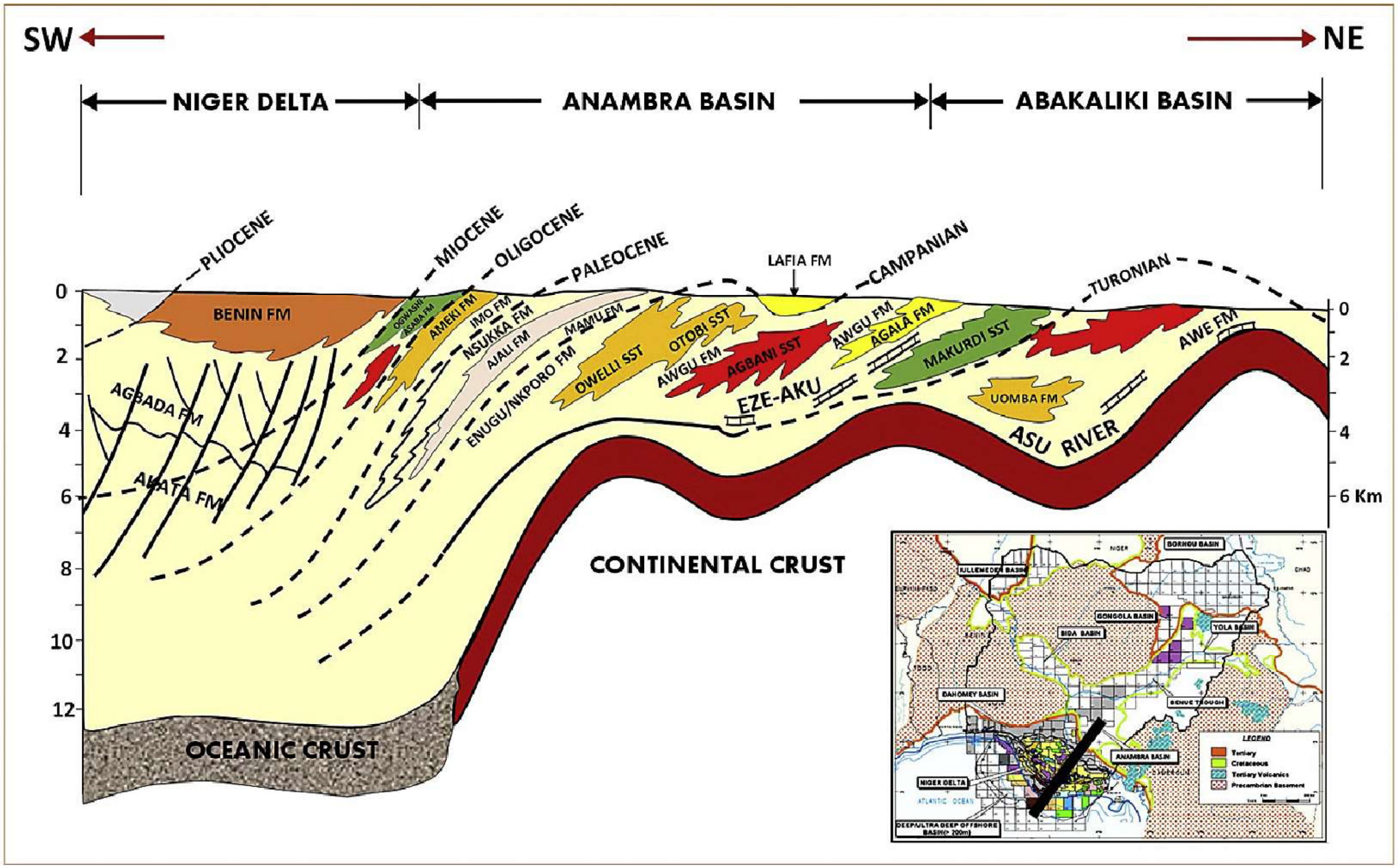

Figure 2.2Cross section Niger Delta, Anambra and Abakaliliki Basins showing their lithosratigraphic unts (After Benkhelil, 1986).

2.3 The Stratigraphy of Niger Delta Basin

The direction and position of the progradational fill in the Niger Delta basin is being controlled by the structural framework of the basin. As the pre Tertiary structural depression was filled, the depositional centres moved seawards consequently and the coastal plain deposits young towards that direction (Fig. 2.2). During Oligocene to Miocene, the Delta complex had prograded southwards into deep waters and out onto the rapidly subsiding oceanic crust. The basin was filled across the narrow continental shelf and beyond the continental margin.

According to Hutchison (1983), the oceanic crust contact is suggested to be the main Tertiary depocenter. As the delta progrades southward onto the oceanic crust, owing to crust failure under sediment load, there was enhanced subsidence. Additional accommodation for sediment was accomplished through synsedimentary faults within the delta pile and prodelta sediment lateral flow. According to Kulke (1995), shale mobility causes deformation in sediments and the deformation happens when two procedures occur. Firstly, shale diapirs were formed after the deposition of Agbada Formation characterized by less dense unconsolidated delta-front sand over the Akata Formation which consists of pressured, higher density prodelta and delta-slope clays. The second procedure was due to slope instability owing to absence of assistance for the under-compacted delta-slope clays of the Akata Formation. The Benin Formation was deposited after the development of several complex structures such as shale diapirs, roll-over anticlines, collapsed growth fault crest, back-to-back characteristics and steeply spaced faults(Evamy *et al*., 1978; Suppe, 1992).

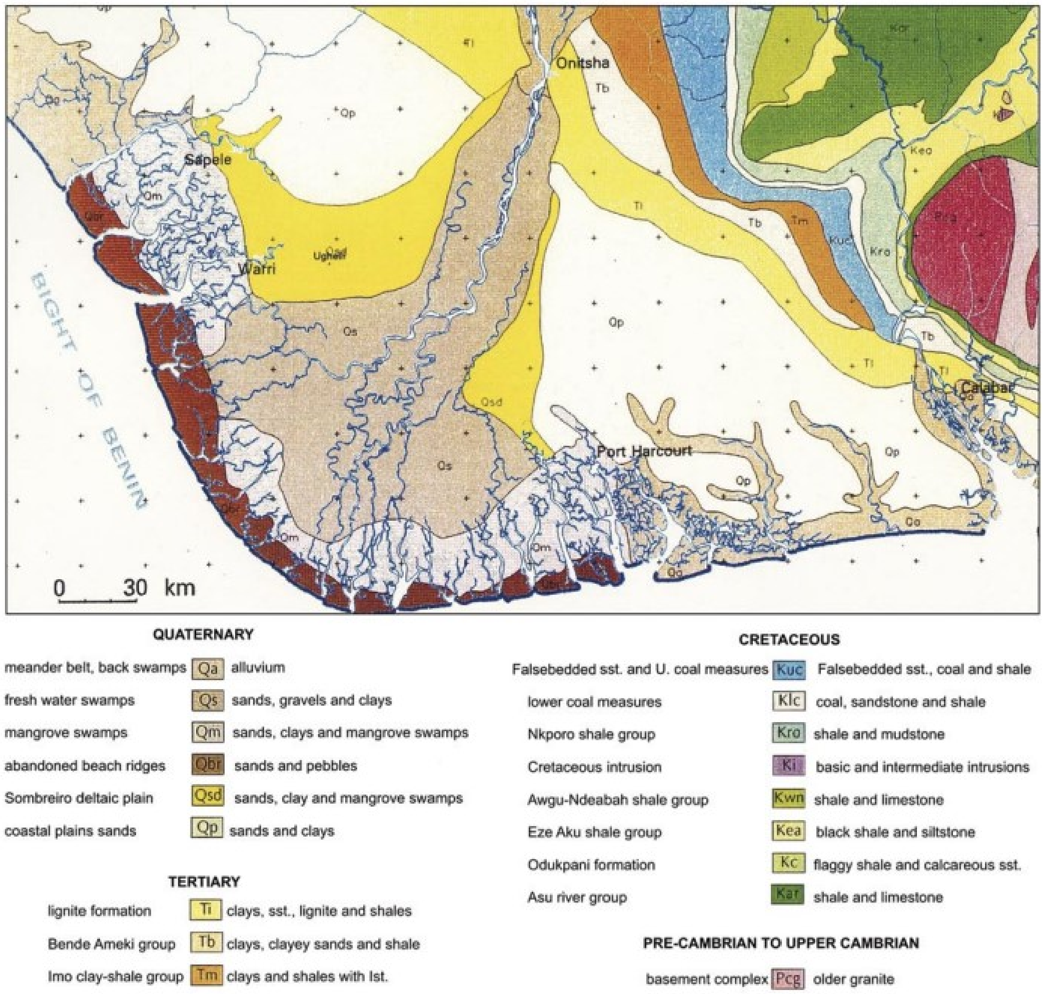

Figure 2.3Geological map of the Niger Delta basin presenting the distributions of the Tertiary, Cretaceous and Quaternary Sediments (After, Reijers 2011)

The sedimentary structure of the Niger Delta basinwas created in a distinctive setup of clastic deltaic prism as a complicated regressive (seaward advance) offlap series. The entire sedimentary portion of the basin is likely to exceed 12 km, according to North (1985). Since Miocene, the sediments have formed a single united system from distinct depocenters. Due to the interdigitization of a tiny amount of different lithologies, it is hard to identify stratigraphic nomenclatures in the basin, making it hard to identify units and limits to discriminate between the Formations.

Evidence from profound wells in the basin, has shown that its stratigraphy can be split into three (3) lithostratigraphic successions or units from Eocene to Recent Age (Figure 2.4) forming a significant regressive cycle (Short *et al*., 1967). The youngest unit is the Benin Formation which consists of continental, fluviatile and backswamp sediments with a thickness of 2500 m. The underlining formation is the Agbada Formation which consist of brackish to marine, coastal and fluvio-marine deposits in a sequence of coarsening cycles of' offlap.

The Akata Formation is the oldest of the triparte lithostratigraphic succession; it comprises of marine pro-delta clays with thickness up to 6500m. The shales are over pressured and have been deformed as a result of delta progradation. Shales are responsible for regional decollement for up-dip extension and down-dip compression. Akata Formation is a world-class source rock with Deepwater turbidite sands also existing within it. The relationship between the subsurface formations in the Niger Delta Basin is presented in Table 2.1.

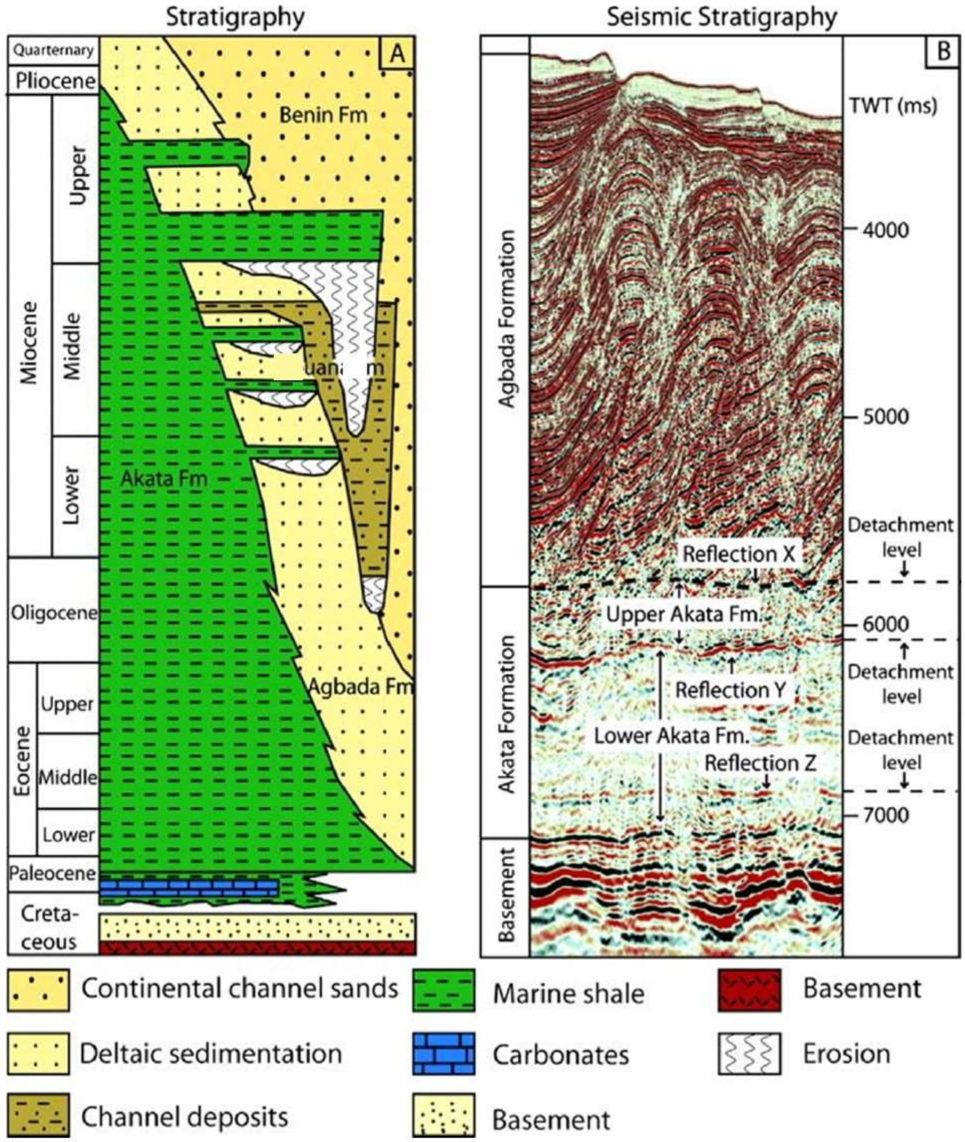

Figure 2.4Different Formations in Niger Delta and their Epoch (After Lawrence *et. Al.*, 2002)

Table2.1Subsurface formations in Niger Delta complexand their surface outcrops (After Short and Stauble, 1967)

			Surface Outcrops	
Formation	Oldest age	Youngest Age	Formation	Oldest Known age
Benin/Afam Clay Member	Oligocene	Plio/Pleistocene	Benin	Miocene
Recent Agbada	Eocene	Miocene	Ogwashi-Asaba	Oligocene
		Eocene	Ameki	Eocene
Recent Akata	Eocene	L. Eocene	Imo Shale	Paleocene
		Palaeocene	Nsukka	Maestrichtian
		Maestrichtian	Ajali	Maestrichtian
Equivalent not known	Cretaceous	Campanian	Mamu	Campanian
		Campanian/Maeastchtian	Nkporo Shale	Santonian
		Coniacian/ Santonian	Agwu Shale	Turonian
		Turonian	Eze-Aku Shale	Turonian
		Albian	Asu River Group	Albian

Episodes of the structural collapse of Niger Delta's wedge of sediments appear can beassociated with the progradation of the Agbada Formation and the overburden on the Akata Shales underlying it (Burke *et al*., 1972; Whiteman, 1982). During third-order eustatic sea level drops, gradation may have been faster. The products of the penecontemporaneous deformation as a result of the sedimentary processes are further distinct in thinnersectionsof the Agbada Formation. This includes the incision of the listric normal faults into the foot walls and the abrupt reorientation of channelized stream paths across fault blocks.

2.3.1 Akata Formation

The formation is the oldest of the three lithostratigraphic succession of the Niger Delta basin, it consists of marine shales with local sandy and silty beds which suggests depositionin prodelta environments such as turbidites deposits and continental slope channel fills (Obaje, 2009).The fauna content of the Formation indicate shallow marine shelf and slope depositional environment (Allen, 1965). The marine shales are typically over-pressured. The oldest rocks of the Akata Formation are thought to be of Paleocene (66.4 Ma) age. The Akata Formation has a thickness ofabout7,000 feetin the central part of the basin (Owoyemi and Willis, 2006).

The formation has adequate intervals with sufficient total organic carbon (TOC) to be regarded as excellent source rocks for petroleum generation (Nwachukwu and Chukwura, 1986). However, the intervals seldom achieve adequate blanket overburden and are immature in different areas of the delta (Evamy *et al*., 1978; Ekweozor and Okoye, 1980; Stacher, 1995).

2.3.2 Agbada Formation

This formation overlies the Akata Formation of the Niger Delta complex. The Agbada Formation consist of interbedded, high energy-deltaic sandstones, siltstones and shales, deposited in numerous offlap rhythms of which its sandy partis generally unconsolidated and theyare the prominent hydrocarbon reservoirs in delta oil-fields, with the facies alternations, varying in proportion and thickness. The shales serve as seals to the reservoirs making them very important petroleum elements in the production of stratigraphic traps for hydrocarbon accumulation. The Agbada Formation comprises of the upper sandstone-shale alterations with sandstones more than the shales; and a lower unit in which the shales is more and thicker than the intercalated sands.

The bottom of the Agbada Formation is not exposed, but it is conventionally taken as the first significant shale body i.e. the top of the Akata Formation. The thickest known section of the Akata Formation is around 10,000 ft. to 15,000 ft. and it varies depending on the structure, depositional position as well as the criteria adopted for definition.The Agbada Formation at the top coincides with the base of fresh water invasion while its base represents the onset of overpressure. The porosity of the Agbada reservoir sands interval ranges from 10 to 30 percent.

The Agbada Formation is thinnest in recent shelf because of the well-developed Akata diapirism and its thickest portion is from Miocene to Pliocene and thinning into sediments of Oligocene and Eocene. The formation youngs down delta from northeast to the southwest. The earliest unit of the formation was estimated to be of Eocene (57Ma). Modern facies are currently laid down in the continental shelf in the mangrove swamp and brackish water environment.

Deltaic offlap sequences characterizes the Agbada Formation and the formation can be broken down into: the onlap or transgressive marine sand; the offlap marine clay; fluvial marine barrier foot deposit; barrier bar deposit; tidal channel deposit and fluviatile deposits. The deltaic offlap sequences of the Agbada Formation, consist of sediments from fluvialtile back swamp and lagoon, barrier bar, laminated fluvio-marine, marine shale and transgressive sands.

2.3.3 Benin Formation

Benin Formation is deposited in the upper deltaic plain environment either as point bars in braided streams or channel fills on natural levees following southward progradation of deltaic deposition into new depobelts. Shales and finer grained sediments were deposited in backswamps and oxbows. The extent of the deposition is delta-wide, with little oil found and it is generally fresh water bearing.

The thickness of this formation commonly ranges between 1,000 to 10,000 feet (Owoyemi and Willis, 2008). The sands are coarse to fine-grained in texture and are poorly sorted having little lateral continuity within the individual sand units. The shallowest part is composed almost entirely of nonmarine sands. The Benin Sands become thinner offshore and pinches out near the shelf edge. The formation typically lacks fauna, and the oldest rocks have been estimated to be of Oligocene (23.7-36.6Ma). However, it is extremely difficult to directly date the Benin sand units because of its large area extent and paucity of index fossils.

CHAPTER THREE

3.0 Methodology

3.1 Data Acquisition

Datasets used in this study was provided byMosunmolu Oil and Gas Limited, Lagos. They include: a post stacked 3D seismic survey, covering an area of 528 square kilometres which was in SEGY format. A composite log of 7 wells; AD1, AD2, AD 3, AD4, AD5, AD6 and AD7, containing Laterolog-Deep Resistivity, Bulk Density, Gamma Ray, RHOB and NPHI logs all in LAS format were also obtained. A summary table showing the log information and description is presented in Table 3.1. Deviation data for well AD6 and AD7 were also made available in *.txt* format. Check shot data from well AD1 was used to convert from time to depth domain across the survey. The spatial distribution of the wells is presented in Fig. 3.1.

The well logs were grouped into three which include lithology logs (Gamma Ray, VSH), resistivity logs (Res, LLD, LLS) and the porosity (Density (RHOB), neutron (PHIN) and sonic logs (DT, 2DT). Well AD 1 has a total depth (TD) of 12,040 ft. (TVDSS) with a Kelly bushing of 45 ft. with Laterlog-Deep Resistivity (LLD), Bulk Density (RHOB) and Gamma ray log. Well 2 has a total depth of 8461 ft. with Gamma Ray (GR) Bulk Density (RHOB) and Resistivity.

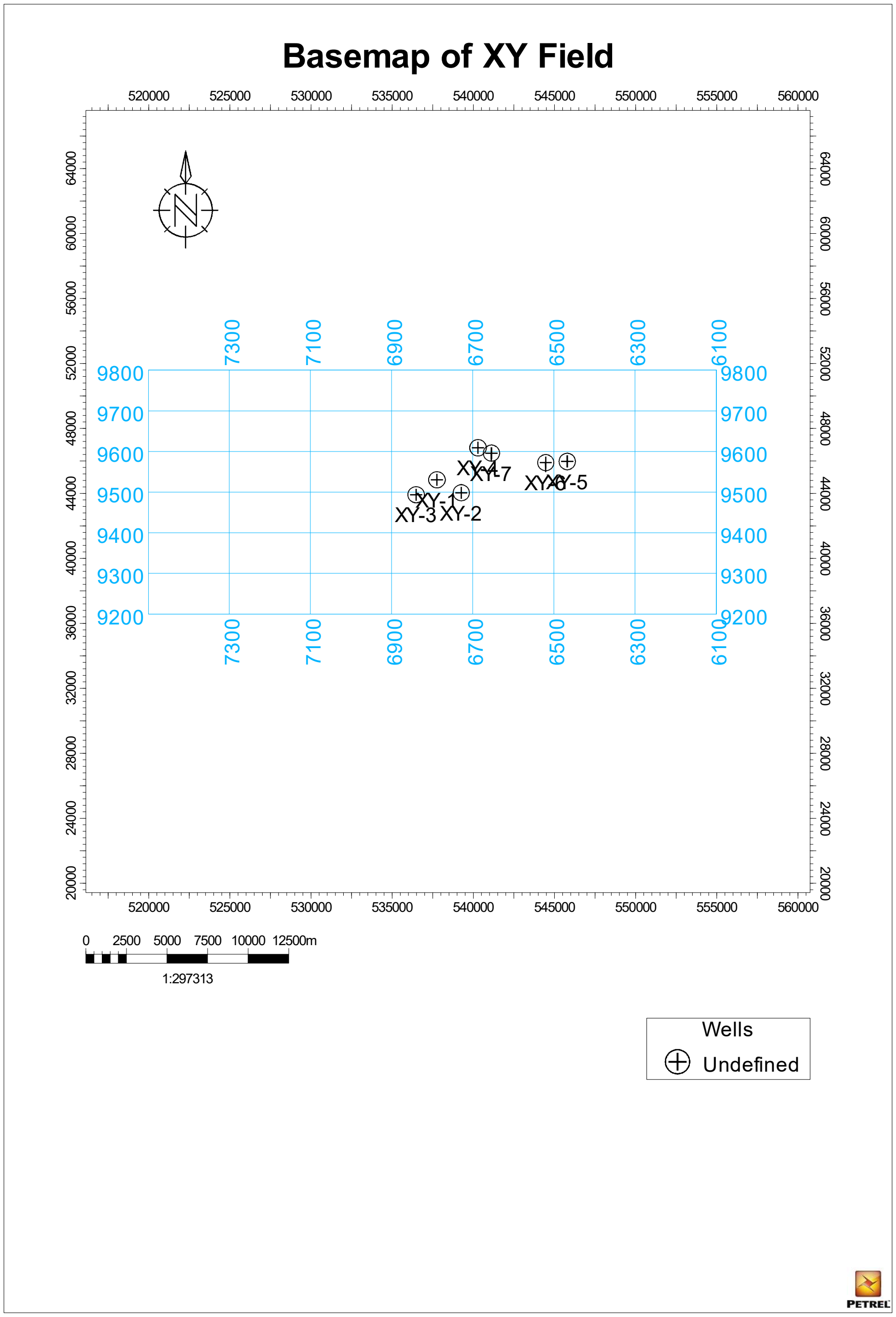

Figure 3.1Basemap of ADField showing the spatial distribution of wells in the AD Field

Table 3.1Well log information showing the depth of the available logs (depth in ft.)

WELLS	TD	GR(API)		RES(Ωm)		NPHI (frac)		RHOB(gcm^{-1})	
		Start	Stop	Start	Stop	Start	Stop	Start	Stop
AD-1	12040	3500	12049	3500	12049	-	-	3500	12049
AD-2	8461	2000	8372	2000	8372	-	-	2000	8372
AD-3	9066	2000	9062	2000	9062	2000	9062	2000	9023
AD-4	12000	3751	11978	3749	11978	3949	11978	3949	7898
AD-5	9800	5900	9753	5900	9753	5900	9753	5900	9753
AD-6	6599	3325	9924	3325	9924	3325	9924	3325	9924
AD-7	5209	4991	10200	4991	10200	4991	10200	4991	10200

3.2 Method of Study

The 3D seismic survey data was used to identify the faults, horizons, boundaries and shape of the reservoirs. Petrophysical model dependent on the well log data (AD1, AD2, AD3, AD4, AD5, AD6 and AD7) were developed. The identified lithologies and shale content were used for well correlation. Estimation of the reserve was carried out with the use of the Net Pay. Reservoir characterization was carried out to understand the geological and petrophysical characteristics of the reservoirs. The workflow used for this investigation is presented in Fig 3.2.Software packages used to analyse the dataset include; Petrel 2013, GeoGraphix Discovery and @Risk. The absence of core, biostratigraphic and production data as well as incomplete Neutron, Density and Sonic logs in some of the wells were the major drawback in this study.

3.2.1 Data Importation

The data collected were interpreted using PETREL 2013 and GeoGraphix Discovery 2013 software packages. Prior to the importation of these data into the software, the data were validated and edited to minimise error. After validation, the well log data which were in LAS data format was imported into PRISM module followed by the importation of well header information which comprises of the name, coordinates and the start and stop depths of the wells into the WELLBASE LAYER module. The post-stacked 3D seismic data were also imported into the SEISVISION module.

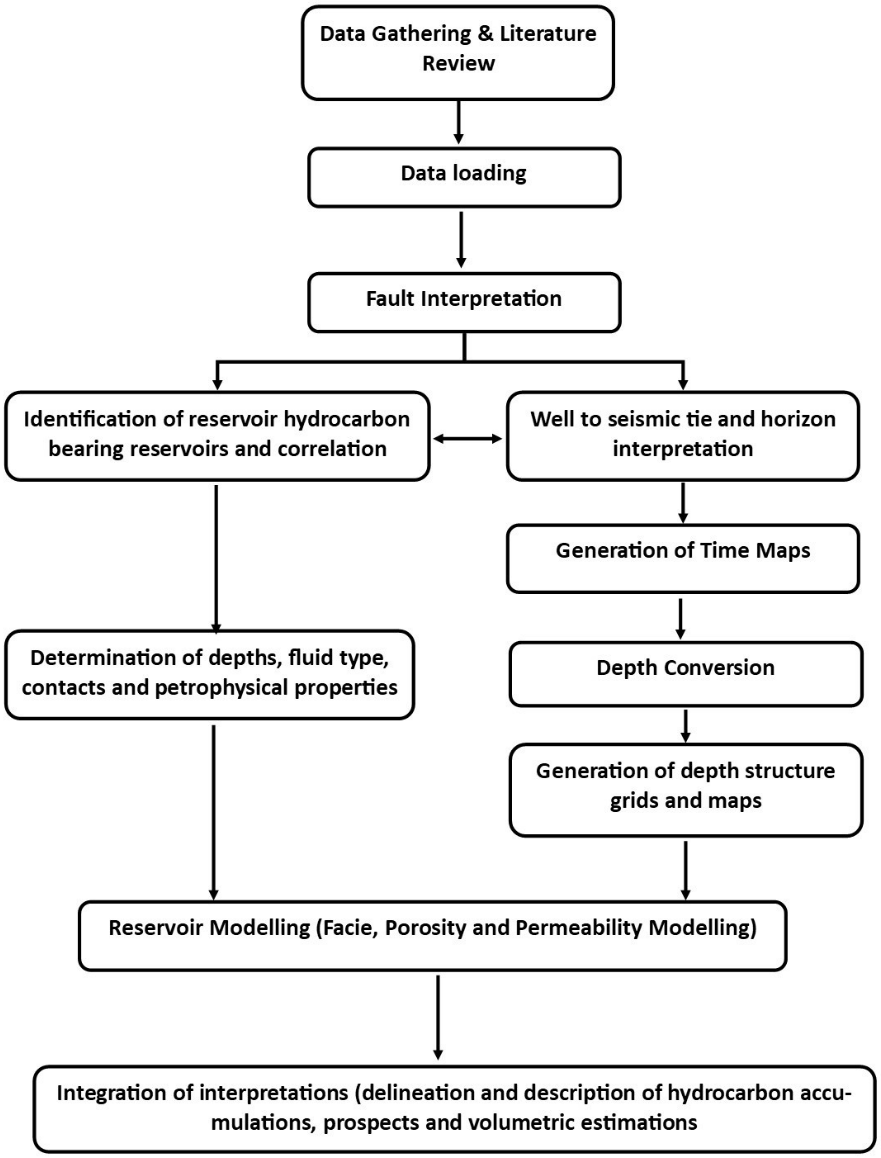

Figure 3.2Workflow for the Reservoir characterization of the AD Field

In order to qualitatively and quantitatively evaluate the reservoir parameters evaluate the hydrocarbon reserve of AD-Field, seismic data interpretation and petrophysical analysis were performed. Deep seismic analysis included interpretations of fault and horizon which were incorporated to produce structure maps both in time and depth domains. Time structure and depth-structure maps were produced using the seismic sections while petrophysical analysis was used to calculate reservoir parameters such as porosity, water saturation, and net to gross (NTG).The procedures adopted for both phases were carried out closely taking into consideration the study's objectives. The petrophysical parameters (Vshale, Swir, NTG, complete porosity and efficient porosity) of the hydrocarbon sand bearing interval and the possible fluid contacts such as; Oil Water Contact (OWC), Gas Oil Contact (GOC), Oil Down To (ODT) were identified. These findings have been used for further assessment of geostatistics.

Uncertainty analysis was carried out to monitor the influence of petrophysical parameters (GRV, Porosity, So and NTG) on the hydrocarbon reserves. The analyses involve the use of ranges of uncertain parameters estimated based on the available data and sound geological assumptions.

3.2.2 Identification of Reservoirs, Fluid types and Contacts

Well log interpretation involved the identification of the different lithofacies using the GR logs. Shales (clay minerals) commonly have a relatively high GR response. A range of 0 to 150 was adopted for the Gamma Ray log. The maximum GR values correspond to the shale baseline, while their minimum values correspond to the sand line. The baseline determined for each of the wells in the study ranges between 55 to 70 API. Gamma ray curves with deviation towards the left of the shale baseline were allocated as sand units while shale was delineated with deviation to the right.

Sandy lithologies were identified with yellow colour while shally lithologies were identified with grey colour for easy identification and thickness evaluation.The lithofacies analysis was performed using the calculator mode of PETREL 2013 tool based on the following equation:

$$Facies = If\ (GR < 70, 1, 0) \tag{1}$$

GR is not a reliable indicator of reservoir sands with radioactive minerals. Resistivity logs and the behaviour of the Density/ Neutron logs also served as a guide and more reliable indicator of reservoir rocksand the delineation of stratigraphic surfaces. The Density and Neutron logs often correspond with the Gamma Ray (GR) log. Density and resistivity logs were compared for any evidence of hydrocarbon as well as to identify the fluid contacts such as Gas-Oil-Contact (GOC) and Oil-Water-Contact (OWC). In classic response, Density, resistivity and GR logs follow each other to the left or right (tramline) in water sands while the behaviour of the curves will mirror each other in hydrocarbon sands (Darling, 2005). Under a quick log evaluation of the log data, high resistivity values were interpreted as probable hydrocarbon-bearing sand units, whereas, the low resistivity readings were interpreted as probably water bearing sand units.

3.2.3 Estimate of Shale Volume

The gamma ray values of the formation under investigation relative to that of nearby clean and shale zones can be used to estimate the shale volume in the formation. The relationship between the gamma ray value and the shale content of a formation may be linear or non-linear. Gamma ray logs were therefore used to calculate Gamma Ray index and the shale volume.

Gamma Ray Index (IGR) is shown as:

$$I_{GR} = \frac{GRlog - GRclean}{GRshale - GRcl} \quad (2)$$

Where:

IGR describes a linear response to shaliness or clay content.

$GRlog$ = Gamma Ray of depth of investigation

$GRclean$ = Gamma Ray of nearby clean zone

$GRshale$ = Gamma Ray nearby shale zone

Linear Gamma Ray - clay volume relationship:

$$Vshale = I_{GR} \quad (3)$$

Non-linear Gamma Ray - clay volume relationships:

Steiber:

$$\text{Vshale} = \frac{I_{GR}}{3.0 - 2.0 * I_{GR}} \quad (4)$$

Shales consist of a mixture of silt materials and clay minerals deposited in a quiet depositional environment. The clay minerals can fix water on their surface complicating the assessment of water saturation. Silt materials are grains of fines, consisting essentially of quartz and minor amount of carbonates and other minerals. Silts are difficult to identify because they have almost similar neutron and density log characteristics with quartz matrix and they are also non-conductors. Therefore, the volume of shales was used to compensate water saturation during analysis involving shaly-sands. The volume of shale is lower than the values estimated if the clay or shale effects are ignored. Over compensation for the shale effect by using large shale volumes can also reduce the value of water saturation and give water producing reservoir interval same signatures with hydrocarbon-producing zone (Hilchie, 1978).

3.2.4 Well Correlation

In order to develop a chronostratigraphic framework for the study area, the wells in the AD Field were all correlated along strike and dip lines. The wells were arranged based on their numbers and location relative distance to each as observed on the base map. Ccorrelation of the wells were carried out to develop a lateral continuity for each identified horizon (sand interval) across the seven wells in the field with the use of the only lithology log available (GR-log) alongside with the resistivity logs. All data were collected using a logging while drilling (LWD) tool. Well logs were provided in LAS format. The volume of shale was determined using the GR method. The Neutron Density cross plot was use to derive the sand and shale matrix. Effective and Total porosity were calculated using the density method. A matrix density (ρma) of 2.65 g/cc and the Indonesia equation were used to estimate the water saturation in the hydrocarbon bearing sand intervals (reservoirs) of interest. No core analysis derived Archie parameters were available. Cementation (m) and saturation exponent (n) values of 1.77 and 1.88 respectively weretaken from literature as commonly usedvalues in Nigeria.

Indonesia equation:

$$S_w = R_t^{(-1/n)} * \{\frac{V_{sh}^{\left(\frac{10V_{sh}}{2}\right)}}{\sqrt{R_{sh}}} + \frac{\phi^{\left(\frac{m}{2}\right)}}{\sqrt{(A * R_w)}}\}^{(-\frac{2}{n})} \quad (5)$$

Where:

$R_{sh} = resistivity\ of\ shale$,

$R_t = true\ formation\ resistivity$,

$R_w = formation\ water\ resistivity$

$\phi_{sh} = porosity\ of\ shale$,

m = cementation,

n = saturation exponent

Vsh = volume of shale

3.3 Petrophysical Interpretation

Sandstones are common oil and gas reservoirs and are a class of economically important sedimentary rocks. Porosity, permeability, velocity and density influence the petrophysical characteristics of sedimentary rocks. These properties are governed in part by characteristics of facies which in turn are linked to processes of deposition. These petrophysical properties are very essential and necessary to predict the movement of hydrocarbon in a reservoir as well as the transportation of contaminants in an underground aquifer.

A combination of well logs comprising of gamma ray (GR), resistivity, neutron (NPHI), density (PHID) and sonic logs from seven different wells together with seismic information were used to carry out a petrophysical analysis. The lithologic units were delineated into hydrocarbon bearing and non-hydrocarbon bearing intervals within reservoirs were delineated and the geometry of the reservoirs was defined by means of well to well correlation. Petrophysical properties of the reservoirs such as: porosity (Φ), permeability, gross thicknesses, water saturation (S_w) and hydrocarbon saturation (S_h) were all determined.

3.3.1 Porosity

Porosity refers to the proportion of a specified quantity of the rock made up of pore space, and therefore can contain liquids. Porosity is usually calculated using data from a tool that measures the rock's response to neutron or gamma ray bombardment, but can also be obtained from the log of sonic and Nuclear Magnetic Resonance. Porosity can be expressed using the Wyllie equation from the sonic log information**.**

$$\phi_s = \frac{\Delta t - \Delta t_{ma}}{\Delta tf - \Delta t_{ma}} \quad (6)$$

Where;

ϕ_s = porosity derived from sonic log

Δt = transit time in the formation of interest

Δt_{ma}= transit time in the matrix materials

Δtf = transit time in the fluid in the formation

In general porosity derived from the sonic logs are inferior to neutron or density calculated porosity (Rider, 1996). The relationship between density log and porosity is similar to the Wyllie's equation;

$$\phi_{Den} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \quad (7)$$

Where:

ϕ_{Den} = porosity derived from density log

ρ_{ma}= Matrix density

ρ_b= bulk density of the formation

ρ_f= density of the fluid

3.3.2 Permeability

Permeability refers to the amount of fluid (usually hydrocarbon) which, as a function of time and pressure, can flow through a rock and it is a function of the degree of interconnection between the pores.So far, formation testing is the only instrument that can assess the permeability of a rock down a well in-situ. Permeability also can be empirically derived using the relationship between other well log measurements (porosity, NMR, and sonic logs). Permeability is often estimated because in-situ measurements are often not available. The following definitions and petrophysics models assumes that shale is composed of silt, clay and bounded by water making them impermeable and non-reservoir rocks and hydrocarbons are stored only in pore space in sand matrix.

3.3.3 Water saturation

Water saturation relates to the water occupying porous space fraction and it is usually calculated using information from a tool that records the rock's resistivity and the symbol is S_w. Irreducible Water saturation, refers to water saturation in which all the water present within a formation adhere on the grains within the formation (Asquith and Gibson, 1982). At irreducible water saturation, water calculated in the uninvaded zone (S_w) will not move because it is held on grains by capillary pressure. A formation at irreducible water saturation will produce water-free hydrocarbon.

It is calculated using the equation below;

$$S_{wirr} = \left(\frac{F}{2000}\right)^{\frac{1}{2}} \#(8)$$

Where:

S_{wirr} = Irreducible water saturation

F = Formation water

3.3.4 Gross and Net Sand thickness

The hydrocarbon bearing sand intervals in the field were identified on the basis of three cut off criteria: the effective porosity of the sand interval must be greater than 8% with water saturation lesser than 55% and shale volume cut offs with lesser than 35%.

3.4 Seismic Interpretation

The seismic data provides the benefit of both two- and three-dimensional data as opposed to the one-dimensional nature of a well bore, making it easy to give a fair representation of the very complex three dimensional subsurface of the earth. Structural mapping is the most important application of seismic data as many of the world's largest oil and gas fields are controlled by subsurface structures (PetroWiki, 2017). The seismic reflections were used to create maps depicting the geometry of subsurface structures in the AD Field. In order to do this, the under listed sequences were used.

3.4.1 Well to seismic tie

Information from the seismic data and the wells were integrated to determine facie and fluid types across the seismic data to generate a synthetic seismogram. Well to seismic ties enables a correlation between the stratigraphic information on the well logs and the reflections on the seismic trace. The process involves the location of marked stratigraphic information from the well such as well tops on the seismic time sections. Synthetic seismograms can be generated with the use of the derivation of the acoustic impedance (AI) from the log data, from which reflectivity may be derived. Checkshot data were used to generate the synthetic seismogram, the conversion of the depth related trace from a depth reference to a time reference was carried out so that the well and seismic information can be compared in the same domain using the seismic section.

3.4.2 Horizon Mapping

Horizons are geological chronostratigraphic surfaceswhich serve as the interface between two distinct layers of rock. Horizons can be mapped because they are linked to continuous and reliable reflection on the sections appearing over a large region. Prior to the proper establishment of the stratigraphic framework of the field, important stratigraphic horizons were mapped and converted from time to depth domain using the check shot data. The time structure maps produced were converted to depth structure maps using the velocity model.

Identification of events (i.e. horizon) to be mapped was based on reflection continuity and strength (amplitude). This implies that most recognizable and continuous event will be easiest to trace through a grid of data. Mapping of reflection (horizons) on the seismic section lies in the proper understanding of the character of the reflections in terms of their amplitude, as it may be positive, negative or cross-over point (inflection point). In tying of loop or closing of loop (i.e. spreading picks across the entire field), care was taken in comparing the mapped section with other sections to identify similar horizons on adjacent lines. Care was also taken to avoid misties (i.e. the depth or time difference between well marker and horizon grid) which could give an erroneous interpretation.

3.4.3 Fault Mapping

Faulted structures are important elements of the petroleum system as they play important roles in the trapping of hydrocarbon, making it imperative to ensure the use of correct and adequate techniques to map them. Faults in the seismic survey were identified based on criteria such as; abrupt termination of reflection events; breaks in reflection events; abrupt lateral velocity changes; overlapping of reflection events; pattern change of reflection events across a fault; structural deformation in beds above the zone of faulting; anomalous dip near the fault zone. The major faults in the seismic survey were identified and mapped along dip lines. In the 3D seismic datainterpretation, faults are better seen and picked on the inlines whereas; horizons are suitably marked on the crosslines before spreading the picks through the entire survey.

In order to have a good resolution of the faults, a scroll increment of 10 lines was employed on both inlines and cross lines while picking the faults on the Petrel software used. Precautions were also made to ensure the consistency of the fault traces owing to the possibility that faults dying out can easily be mistaken for another in a field with a complex fault system. In order to ensure consistency, seeded, manual and guided fault tracking system were used as a guide to continual fault picking on subsequent lines. The faults were identified on the seismic section on the basis of their reflection discontinuity at fault planes, vertical displacement of the reflections, mis-closures in tying reflections around loops; abrupt termination of events, overlapping of reflections and change in pattern of events across the faults.

3.4.4 Generation of Maps

Structural maps were generated on the seismic section to evaluate the geometry of the hydrocarbon horizons. The horizon maps were generated both in time and depth domainto aid in the data interpretation.

3.5 Reservoir Estimation of Hydrocarbon initially in Place

Volumetric estimation of reserve is important because it acts as a guide for field exploration and development as well as form critical issue for both economic and other technological reasons (Masoudi, 2011). The combination of the static, structural and t petrophysical models are important in the volumetric estimation of reserves. The main challenge in achieving significant reservoir assessment is to correctly define the reservoir rock geology in order to calculate its reservoir quantity within acceptable limits. The determination of the GRV and estimation of petrophysical parameters such as; porosity, oil saturation, gas saturation and oil formation volume factorof the reservoir are needed in estimating the hydrocarbon in place (HIIP).

Volumetric estimation of the original hydrocarbon in placemakes use of static parameters such as the area of accumulation (A), pay thickness (h), porosity (φ), and initial fluids saturation (S_w) of the reservoir. However, due to the uncertainties associated with the vailable data sets, statistical methods such as Monte Carlo simulations can be used to quantify the effects of uncertainties on HIIP volumetric estimates (Murtha, 2001). The estimation of hydrocarbon at reservoir condition (HIIP) can be done using:

$$HIIP = A \times h \times \varphi \times (I - S_w) \quad (9)$$

The percentage of the void space within the reservoir is calculated as the product of the GRV and porosity (ϕ), the value of the original oil-in-place (OOIP), expressed in reservoir barrels (RB) can be estimated when the void space containing oil is multiplied by oil saturation (S_h) and formation volume factors (FVF) are applied to convert the resultant volumes. The OOIP is expressed in stock tank barrels (STB) and can be expressed in reservoir barrels (RB) by making use of the oil formation volume factor (FVF).

$$HIP = \frac{GRV \times NTG \times Porosity \times S_h}{FVF} \quad (10)$$

3.5.1 Deterministic HIIP calculations

The hydrocarbon resource evaluation was carried out in GeoGraphix using basic volumetric formulas to calculate. The value of the Stock-tank-oil-in-place (STOIP) is given by:

$$STOIP = 7758\ \frac{GRV \times \mathrm{NTG} \times \varphi \times S_O}{B_O} \quad (11)$$

Where:

STOIP = stock tank oil-in-place (STB),

GRV = Gross Rock Volume (acre-ft.)

NTG = Net to Gross ratio

φ = porosity

S_o = Oil Saturation (1-S_w)

B_o= Oil formation factor (RB/STB)

(Expansion factor = 1/B_o which is a “shrinkage factor” asB_o > 1

Gas-initially-in-place (GIIP) was calculated using:

$$\mathrm{GIIP} = 43560\ \mathrm{x} \frac{GRV\ \times \mathrm{NTG} \times\ \varphi\ \times\ S_g}{B_g} \#(12)$$

Where:

GIIP = gas-initially-in-place (ft^3),

GRV = gross rock volume (acre-ft.)

NTG = net/gross ratio

S_g = gas saturation (fraction)

$B_{g =}$ gasformation factor (RCF/SCF)

(Expansion factor = $1/B_g$ as$B_g < 1$).

Oil shrinkage factor is used because oil shrinks at the surface as volatile gas is separated while gas expansion factor is considered as gas expands as a result of the lower pressure on the surface. Surface quantities such as the stock tank barrels (STB) and standard condition cubic feet (SCF) are the values used for measuring the hydrocarbons in place (HIP) and not the reserved barrels (RB) or reservoir cubic feet (RCF). The hydrocarbon resource evaluation was carried out in GeoGraphix using basic volumetric formulas to calculate the Gas initially in Place (GIIP) in standard cubic feet:

3.5.2 Uncertainty Assessment

Risk and uncertainty analysis are an important aspect of hydrocarbon exploration and reserve estimation (Garb, 1986). Several techniques for uncertainty assessment in reservoir production and evaluation have been reported in literature. The success rate achieved in adequately predicting hydrocarbon reserves has been poor due to organizations reporting different reserve estimates even with the same data sets. The uncertainty in reserve estimation often revolves around the issues of dependency and aggregation of data.

Deterministic and stochastic techniques are the most popular methods of reserve estimation. Both methods require the use of mathematical formula to estimate volumes of hydrocarbon and their difference is presented in Table 3.2. The deterministic method makes use of single value inputs of reservoir parameters which can only generates corresponding volumetric values obtained as single best estimate values. Stochastic reserve estimation has no standard; it involves the use of a continuous probability density function (PDF) together with combined probability distribution to generate a PDF for reserves. The PDF's of the reservoir parameters in AD Field were combined analytically by random sampling using Monte Carlo Simulation. Important uncertainties in reservoir parameters include porosity, depths of the oil-water contacts (OWC), gas-oil contacts (GOC), net to gross ratio (NTG), water saturation and oil saturation. The influence of saturation (S_w), Porosity (φ), NTG and GRV on the reserve estimateswere identified and quantified in this study using their coefficient of variation.

Table 3.2 Differentiating between Deterministic and Stochastic methods

	Stochastic	Deterministic
1.	Random (Seed number)	It is unlikely due to unpredictable factors
2.	It generates different equiprobable results for different seed numbers	It generates the same result for a given set of initial conditions
3.	Variable states are described by probability distributions	Variable states are described by unique values
4.	It does not need upscaled cells:	Need upscaled cells-needs more data
5.	Unconditional modelling	
6.	Allows more complexity and variability in the model – can help assess uncertainty	Faster to run

3.5.3 Monte Carlo simulation

The simulation exercise was used in this study to quantify uncertainties in the reserve estimates. The process involves several iterations of the model numerous times with random selection generated from the input distributions for each of the petrophysical parameters. The simulation generates various scenarios; together with a statistical output to display the degree of risk or uncertainty involved and can provide a "most probable" situation. Computer programs facilitate the quick execution of thousands of random sampling. Palisade @Risk was used to carry out a Monte Carlo simulation exercise for this studies in order to identify and quantify the influence of limited information or uncertainties generated from factors such as; the available extent of the reserve, rock type, gas content, water content and percentage recoverable hydrocarbon while calculating for the potential oil reserves.

Monte Carlo simulation engages the use of a model. Models are one or more equation based on assumptions and logic, relating the parameters in the equation. These models were built in a spreadsheet, taking input distribution and capable of displaying the output functions of the inputs. This technique is an alternative to both deterministic estimation approach which renders a single value and the scenario approach that renders the worst, most likely, and best-case scenarios. The following description is drawn largely from Murtha (1997). For purposes of illustration, the volumetric model for oil in place (N)was calculated using the formula below after geological parameters such as; GRV,φ, S_w and B_O were all supplied into the @risk decision making software.

$$N = 7{,}758Ah\varphi\ (1 - S_w)/\ B_O(13)$$

Where:

Area = A: Net pay = h; porosity = φ, water saturation =S_w, and formatter volume factor = b_o.

Analysis of uncertainty in reserve estimation is influenced by the number of iterations (Adeloye *et al.*, 2015). Thus, each of the parameters was considered as a random variable and for each Monte Carlo simulation, the parameters were subjected to 10,000 iterations. Latin hypercube statistical (LHS) sampling method and Mersenne Twister algorithm were used to generate near random sampling of the parameters values and pseudorandom numbers respectively with a random seed of 1,384,176,870 for 3 seconds. The procedures required by the software algorithm for assessing uncertainty are as follows;

The geological data to be used were inputted into the spread sheet of the @Risk Software after which probability distribution functions (PDF) were generated using triangular distributions functions. The Input randomness was tested by minimization of Chi-Square distribution and the numbers of the intervals were computed using Stugies equation and the reserve distribution was predicted using Monte Carlo Simulation. Multiple realizations of structures in terms pessimistic (P10), most likely (P50) and optimistic (P90) were generated. Error parameters which include the average, standard deviation (SD) and the coefficient of variation were estimated using the parametric simulation technique. The procedure was concluded by running a sensitivity analysis on the software.

3.5.4 Sensitivity Analysis

Tornado diagrams, graphically presenting the sensitivity of some of the reservoir parameters on the reserve estimates, were plotted using the regression coefficients. The bars on the Tornado diagram represents the regression coefficients which reflects the impact of the input (geologic) parameters on the output (STOIIP, GIIP and Reserve). A positive coefficient, with bars towards the right, indicates that the geologic parameters have a positive impact such that there is increase in the output value. A negative coefficient with bars extending to the left indicates that the geologic parameters have a negative impact on the output values.

3.6 Static Modeling

Static geological model for AD Field was built with the aim of generating a dynamic simulation process showing the spatial representation of facie, porosity, permeability and saturation as well as capturing all key heterogeneities and reservoir connectivity that can affect reservoir performance. Spatial distribution and geometry of lithofacies depends on depositional environment and tectonics. Static models provide a close representation of subsurface realities encountered by the wells and they can describe reservoir production behaviour as well as accurately evaluate the reserve estimates. They can also outline the reservoir geometry and produce lateral continuity for the petrophysical parameters. Static models can also be used to identify new field opportunities with low risk by using a litho-framework. However, it is important to note that static modelling is not a precise representation of a reservoir, it is only an approximation. Models may contain errors of both conceptualization and implementation.

3.6.1 Permeability Model

Permeability models were developed from wells permeability data. The data were distributed across the static model generated with the Sequential Gaussian Simulation (SGA) algorithm trained specifically for zone of the facie to be modelled. The permeability criteria cut-off used for the permeability model was 50 mD.

Realizations from the simulation were iterated on the permeability models and conditioned.

3.6.2 Water Saturation Model

Due to the lack of core information, the average water saturation (S_w) derived from the petrophysical interpretations, were used for the model.$S_w$value of 0.26 was used to model and capture the input parameters from the petrophysical analysis

3.6.3 Facie Model

The facie model was developed using the Sequential Indication Simulation (SIS) technique. This technique provides a better way of modelling of facies were the volume proportions vary in the lateral and vertical dimension or in both. Non reservoir facies where identified with a GR cut- offs of less than 75 API units, so as to delineate the facies in the reservoir into good and moderate facies depending on the GR distribution across the model. The facie modelling process involved facie realizations which were conditioned to the well in order to determine inherent heterogeneity of the facies.

CHAPTER FOUR

4.0 Results and Interpretation

4.1 Seismic interpretation

Structural framework showing different oriented growth faultsidentified, picked at every 10^{th} inlineand mapped across the entire seismic survey using the Ant Tracking attributeis presented in Figure 4.1. Sixteen (16) faults, labeled Flt 1 to Flt 16 were identified. The faults were observed to be elongate and generally trending East to West. The interpreted faults and horizons across on inline 6656 and Xline 9578 areshown in Figures 4.2 and 4.3respectively. The faults observed on the inline were predominantly listric normal growth faults, with sub parallel relationship. They illustrate an extensional collapse of the passive continental margins. Fault Flt 2 (Figure 4.1) was identified as the major synthetic active growth fault controlling the field.

Roll over anticlines were formed as a product of the deformation of deposited sediments at the downthrown of the block of major faults Flt1, Flt2 and Flt3 in the seismic survey (Fig.4.1). The reservoirs in the seismic survey were observed to be roll over anticline structures, bounded by the closure of the two major synthetic faults which provided the structural dip closure (trap) responsible for hydrocarbon accumulation in the field (Fig. 4.2). The syndepositional roll over anticlines identified at the downthrows of the faults Flt1, Flt2 and Flt3 have developed during sedimentation with each layer of the sediments showing thickness towards the direction of faults (Fig. 4.2). The wells in this study were drilled to target the downthrown of fault Flt2. Fault Flt 2 cuts through the entire breath of the mapped area and Flt3 forms a dip closure with it on the eastern portion of the survey and trends south west to the middle of the seismic survey (Fig 4.1).

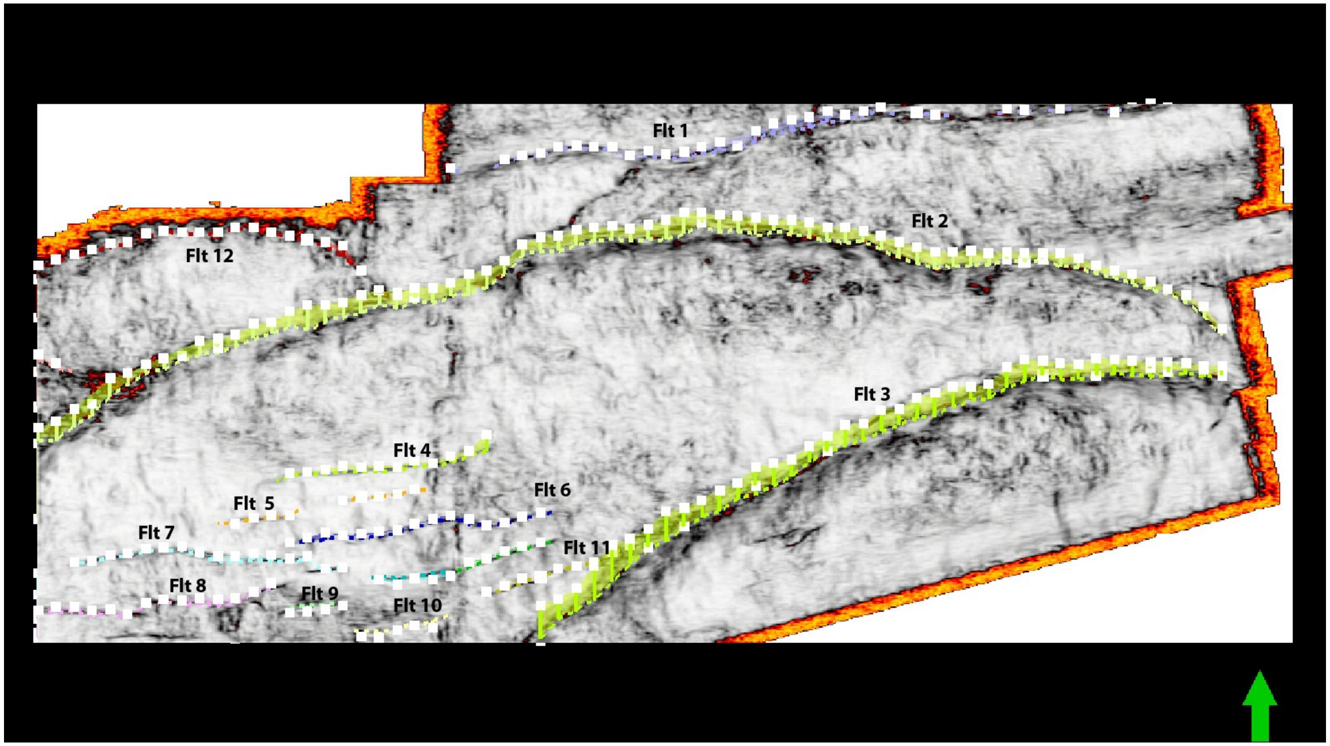

Figure 4.1 Structural framework showing faults picked on Ant Tracking attribute; fault follows the W-E trend across the AD Field.

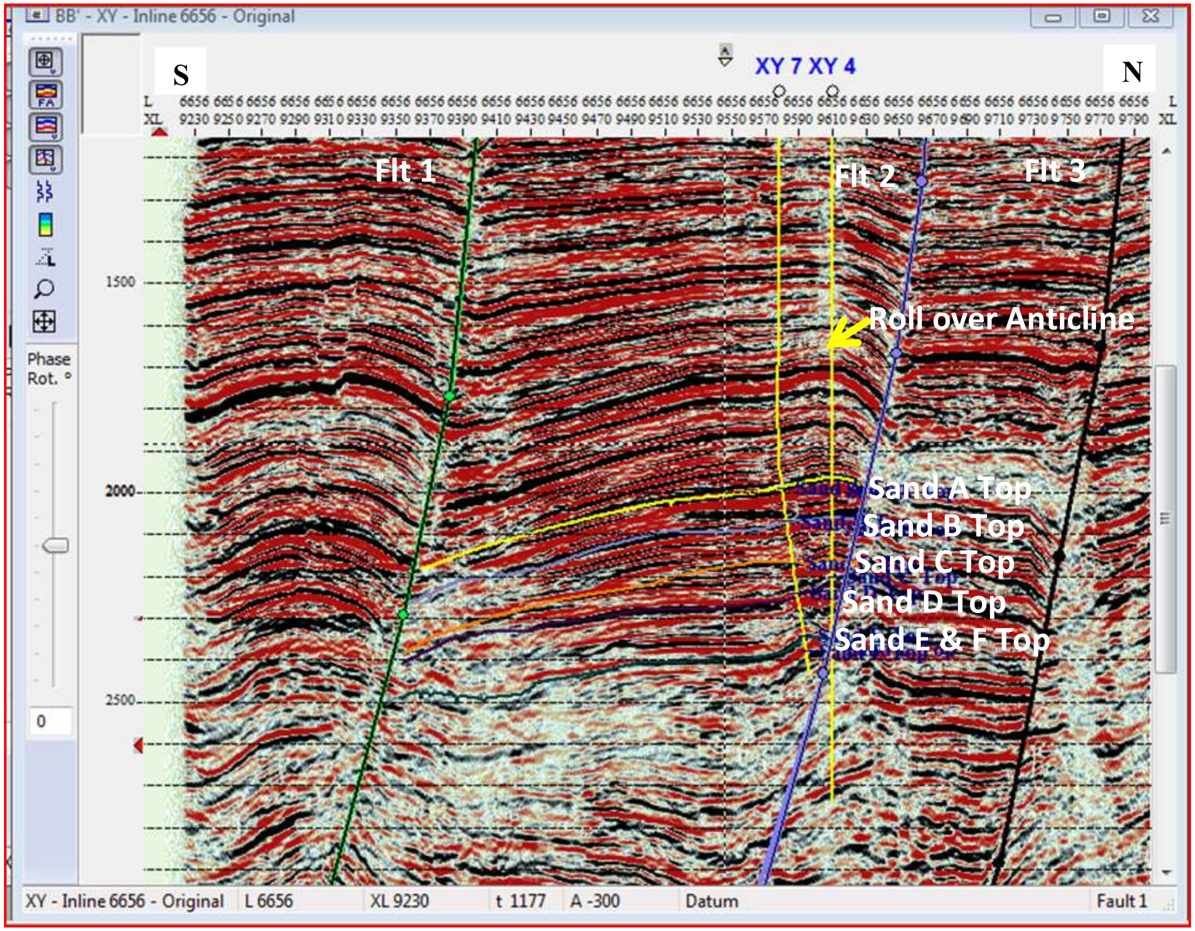

Figure 4.2 Inline (6656)showing Interpreted fault, horizons and wells on the roll over anticlines

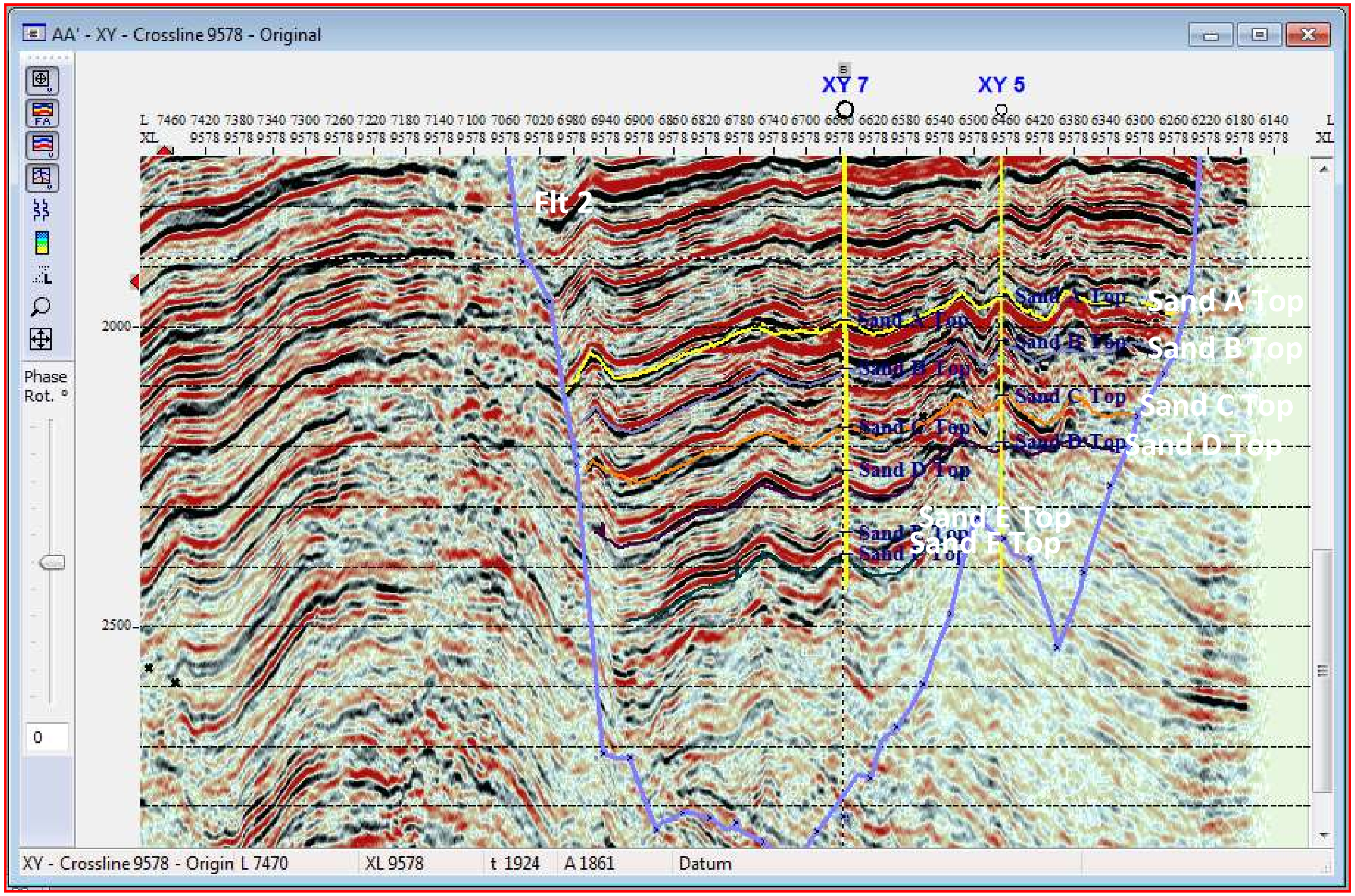

Figure 4.3 Xline (9578) showing a fault (Flt2), the reservoir tops with AD7 and AD5 wells

4.2 Well Correlation

The lateral continuity of hydrocarbon bearing sand intervals were correlated across the field using the GR and Resistivity logs to give a good description of the reservoirs and to determine the lateral continuity of the sand intervals.The correlation chart and cross-section of the wells from East to West in the following order: AD3, AD1, AD2, AD4, AD7, and AD6 to AD5 are shown in Fig.4.4. Six sand intervals, which serve as reservoir units within the Agbada Formation, weredetermined and labeled as Sand A, B, C, D, E and F. The correlation exercise shows that six reservoirs have good continuity, generally elongate and can be identified, mapped and correlated across the well in the field (Fig 4.4). The sand intervals were observed to thin towards the basin from the North to the south suggesting a prograding sequence.

4.2.1 Depositional Environment

Several publications have reported the determination of depositional environment from log shapes (Garcia, 1981, Schlumberger, 1985). The GR log pattern was used to correlate the horizons across the AD Fields (Fig. 4.4). The sand intervals observed in the wells vary from blocky to ratty sand. A quick look evaluation of the log facies of the GR logs across the Field showed that the Benin Formation is characterized with blocky sands with a combination of serrated and cylindrical patterns diagnostic of deposits of deltaic progradation and river flood plains (Etu-Efeotor, 1997). Agbada Formation was identified with log motifs of ratty sands with intercalation of sands and shales of point bars of a distributary channel fills, coastal barriers and shore face deposits (Etu-Efeotor, 1997).

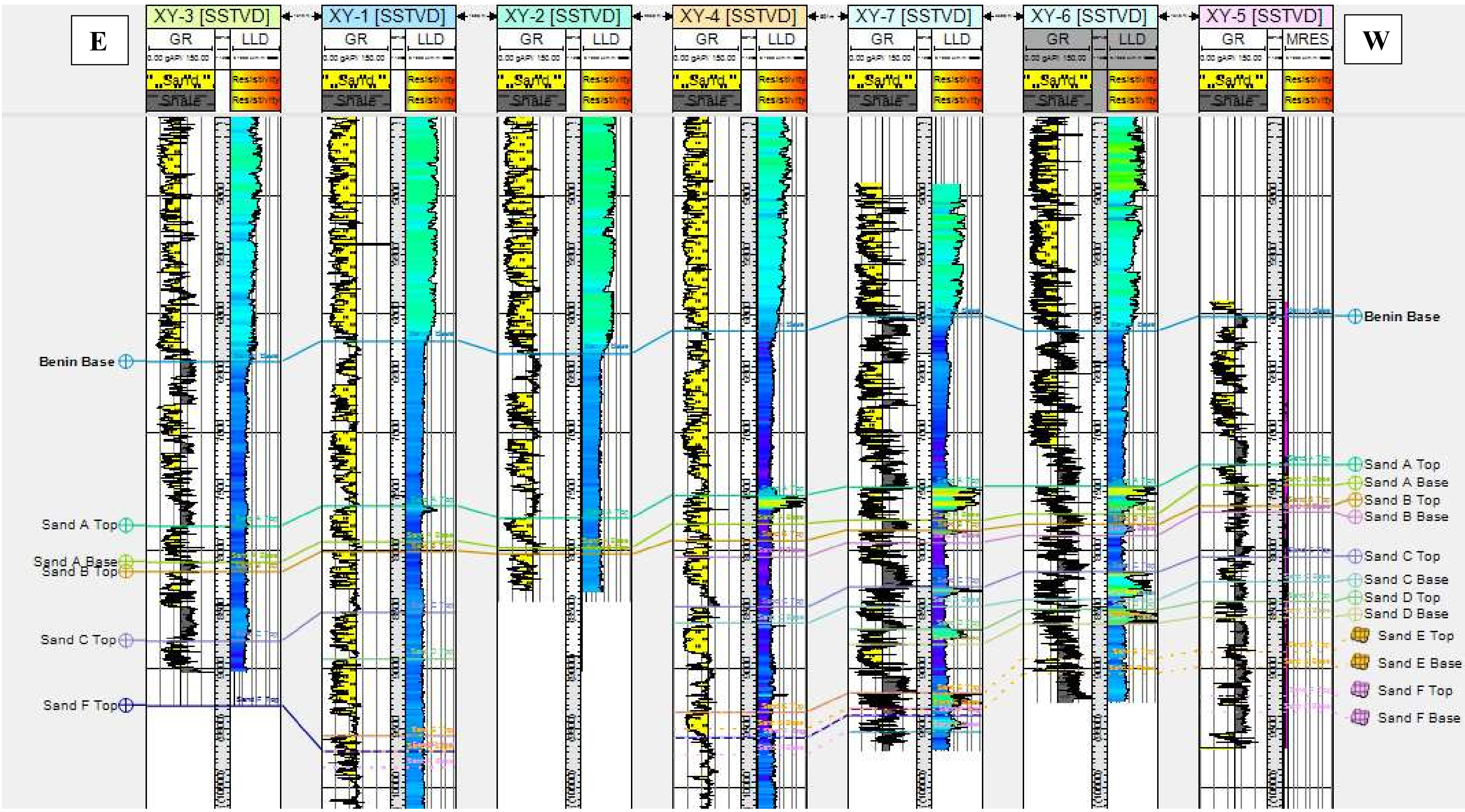

Figure 4.4 West-East correlation of hydrocarbon bearing sand across wells in the AD Field

Resistivity and gamma ray logs were used for fluid typing i.e. to discriminate the hydrocarbon bearing sand interval across the wells in the field. The blocky sand interval of the Benin Formation show high resistivity indicative of the presence of fresh water as formation fluid (Fig 4.4). The resistivity logs of wells on the western portion of the survey (AD1, AD2 and AD3) were observed to have sand intervals corresponding with low resistivity curves, indicating that the fluid within the reservoirs are predominantly saline water and these wells were regarded as "Dry wells". The Agbada sand intervals identified within wells AD4, AD5, AD6, and AD7 were observed to correspond with higher resistivity suggesting accumulation of hydrocarbon. Hence, further logging information were obtained for only well AD4, AD5, AD6, AD7, AD8 which were the only useful wells for this study.

4.3 Horizon Interpretation and Reservoir Description

In order to understand the subsurface geology and structural trend for possible hydrocarbon accumulation, seismic and well data were tied. Based on the seismic to well ties, six major horizons identified on the well logs were picked and interpreted across the seismic survey. The six hydrocarbon bearing sand units (Sand A to F) within the Agbada Formation which are the interval of interest were mapped within the seismic section (Fig. 4.2). Contour maps showing the most accurate representative geology of Sand A, B and C are presented as both time (Isochron) maps and depth (Isopach) maps in Figs. 4.5-4.7. The maps show the two major faults (Flt2 and Flt3) that formed the closure that contributes to the accumulation of hydrocarbon in the Field.

Both time and depth structure map of the surface of Sand A reservoir is presented in Fig. 4.5. The depth map has contour lines varying from -7413.73 ft. to TVDSS of -7683.75 ft.

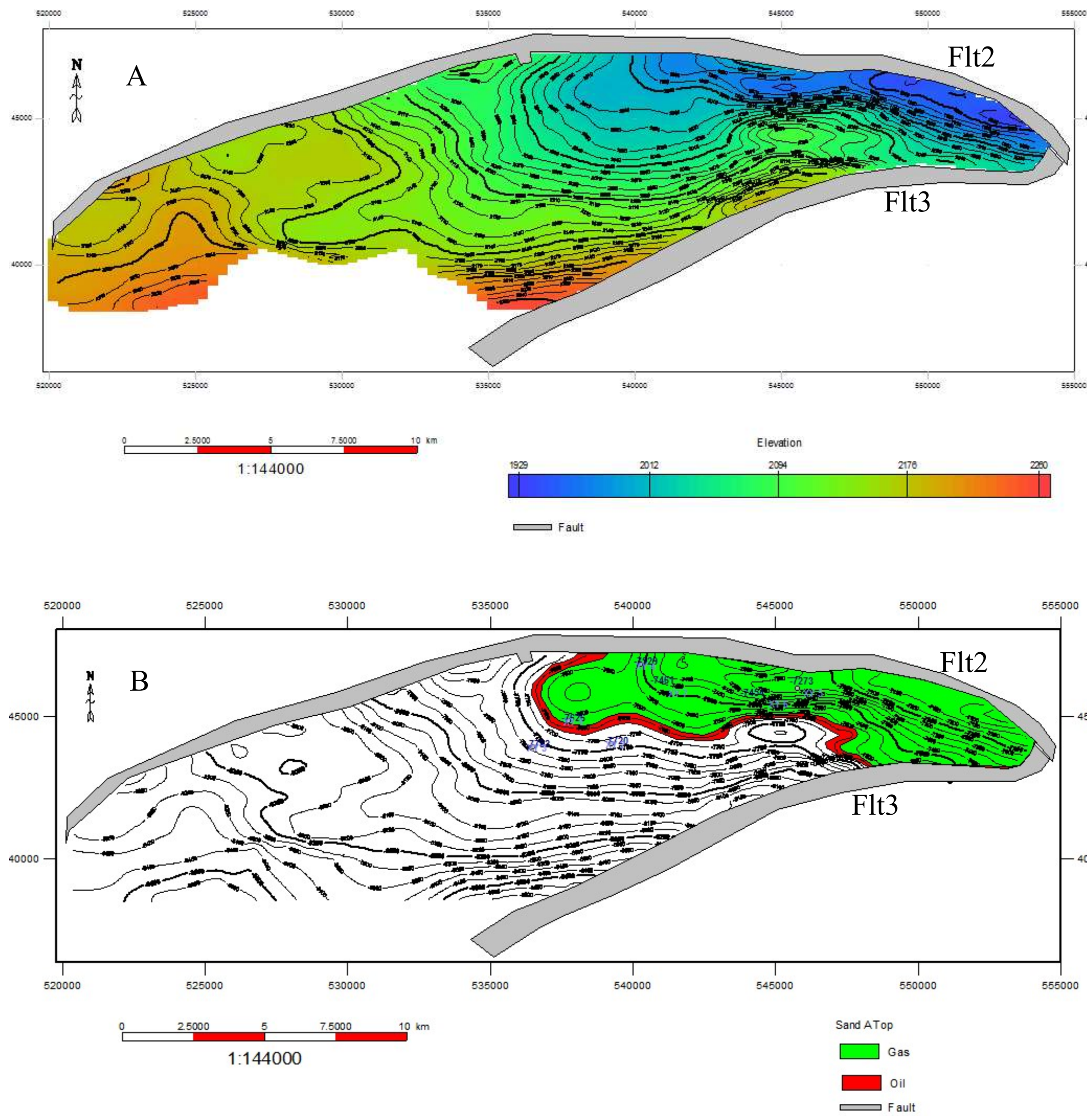

Figure 4.5 A.) Isochron map B.) Depth Structure Map of Sand A showing accumulation of gas and oil at the closure between Flt2 and Flt3

with an average gross interval of 270.02 ft. across the wells. The lowest point on the horizon is along the north-eastern portion. Flt2 and Flt3 were identified as the two major faults forming the structural closure responsible for hydrocarbon accumulation in the Field. Four wells AD4, AD5, AD6 and AD7 were observed to have penetrated the reservoir unit to target both oil and gas accumulation.

The time and depth structure map of the surface of Sand B reservoir is presented in Fig. 4.6. The depth map has contour lines varying from -7778 ft. to TVDSS of -7878 ft. with an average gross interval of 59 ft. across the wells. The lowest point on the horizon is along the north-eastern portion. Flt2 and Flt3 were identified as the two major faults forming the structural closure responsible for hydrocarbon accumulation in the Field. Two wells AD6 and AD7 were observed to have been penetrated the reservoir unit to target both oil and other hydrocarbon prospect the reservoir.

The time and depth structure map of surface of Sand C reservoir is presented in Fig. 4.7. The depth map has contour lines varying from -8176 ft. to TVDSS of -8624 ft. with an average gross interval of 299 ft. across the wells. The lowest point on the map is along the north-eastern portion. Flt2 and Flt3 were identified as the two major faults forming the structural closure responsible for hydrocarbon accumulation in the Field and wells AD6 and AD7 were observed to have been situated to target the gas reserve in the reservoir.

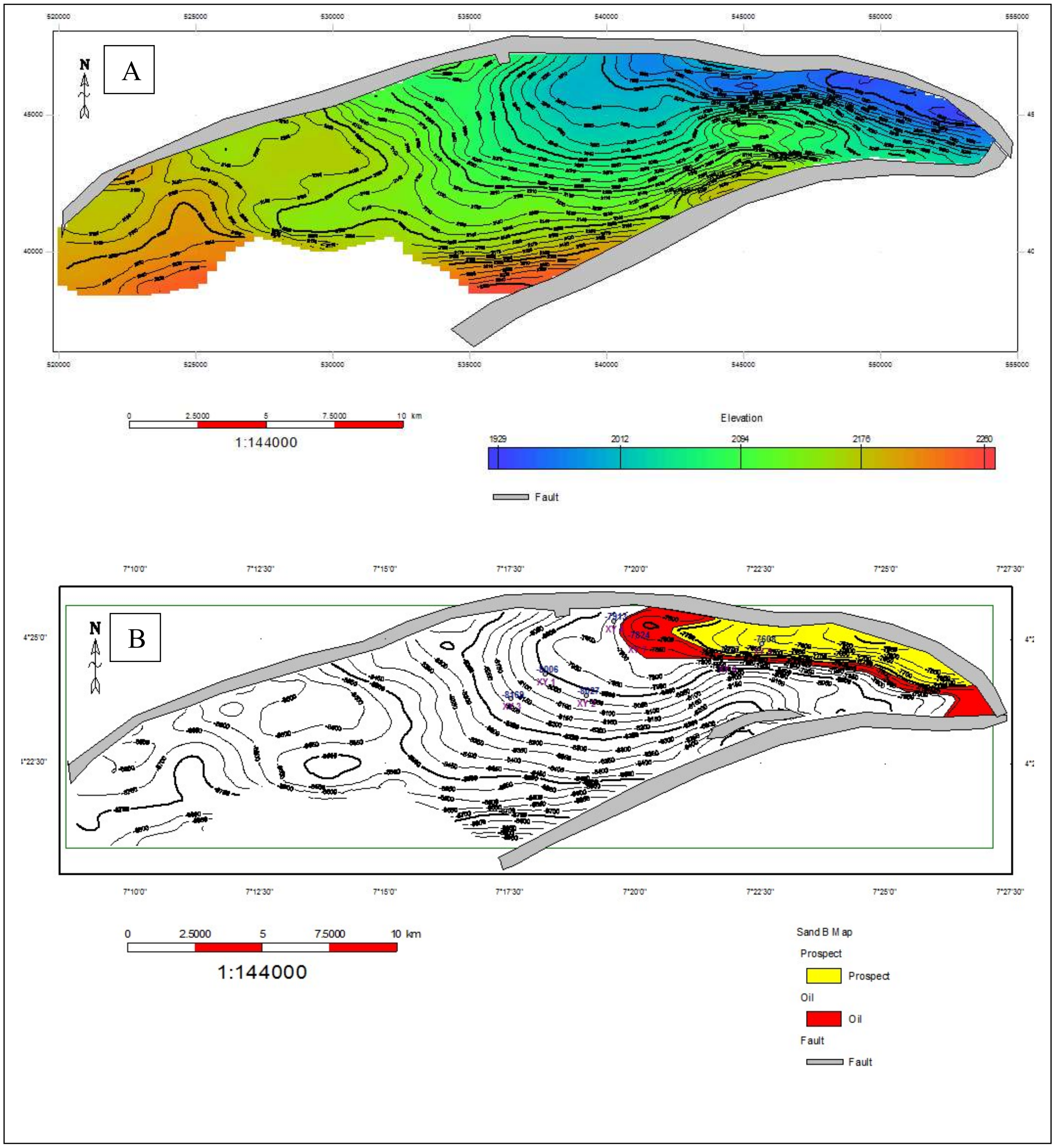

Figure 4.6 A.)Isochron map B.) Depth Structure Map of Sand A showing accumulation of oil and hydrocarbon prospect at the closure between Flt2 and Flt3

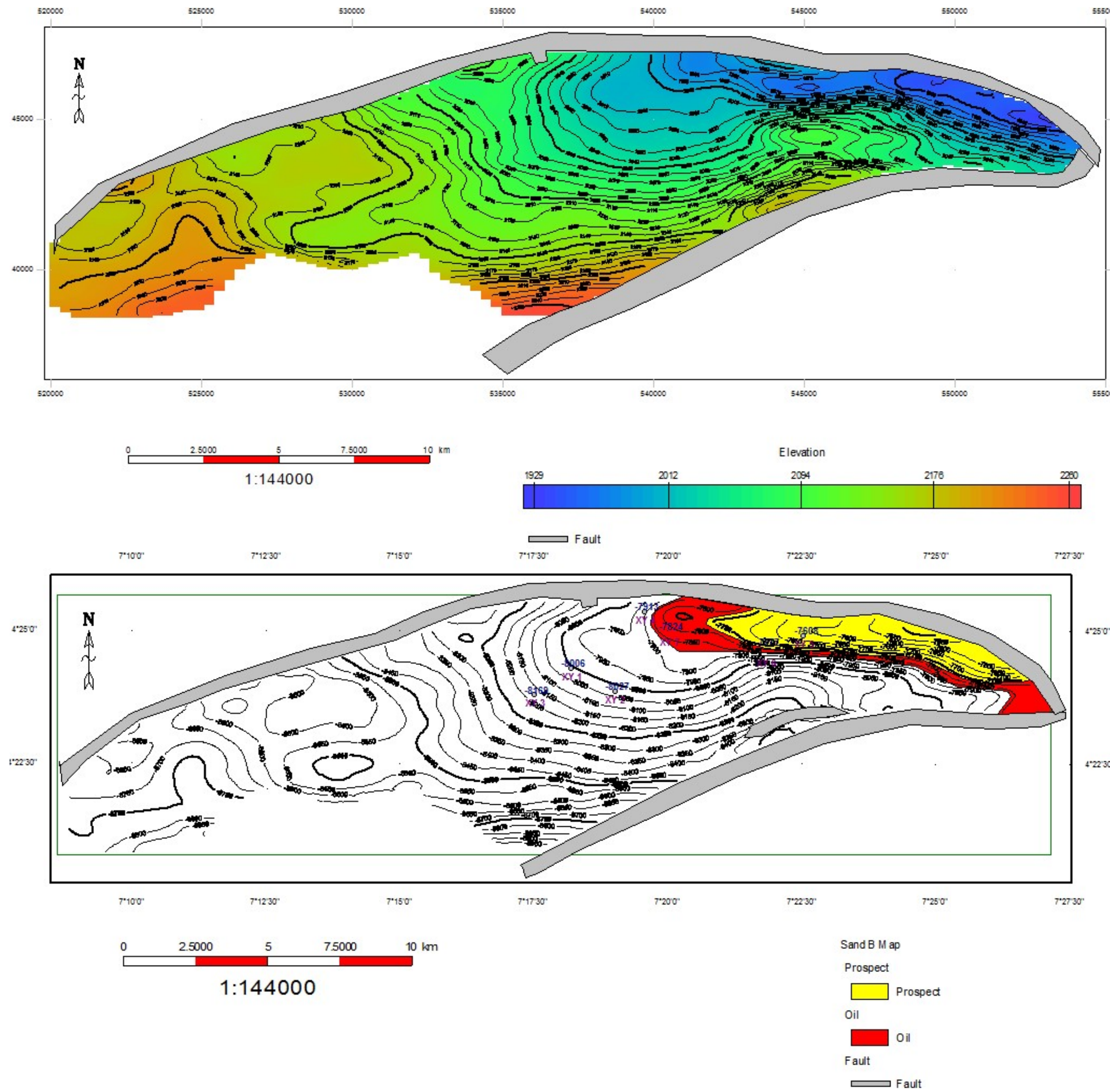

Figure 4.7A.) Isochron map B.) Depth Structure Map of Sand B showing accumulation of oil and hydrocarbon prospect at the closure between Flt2 and Flt3

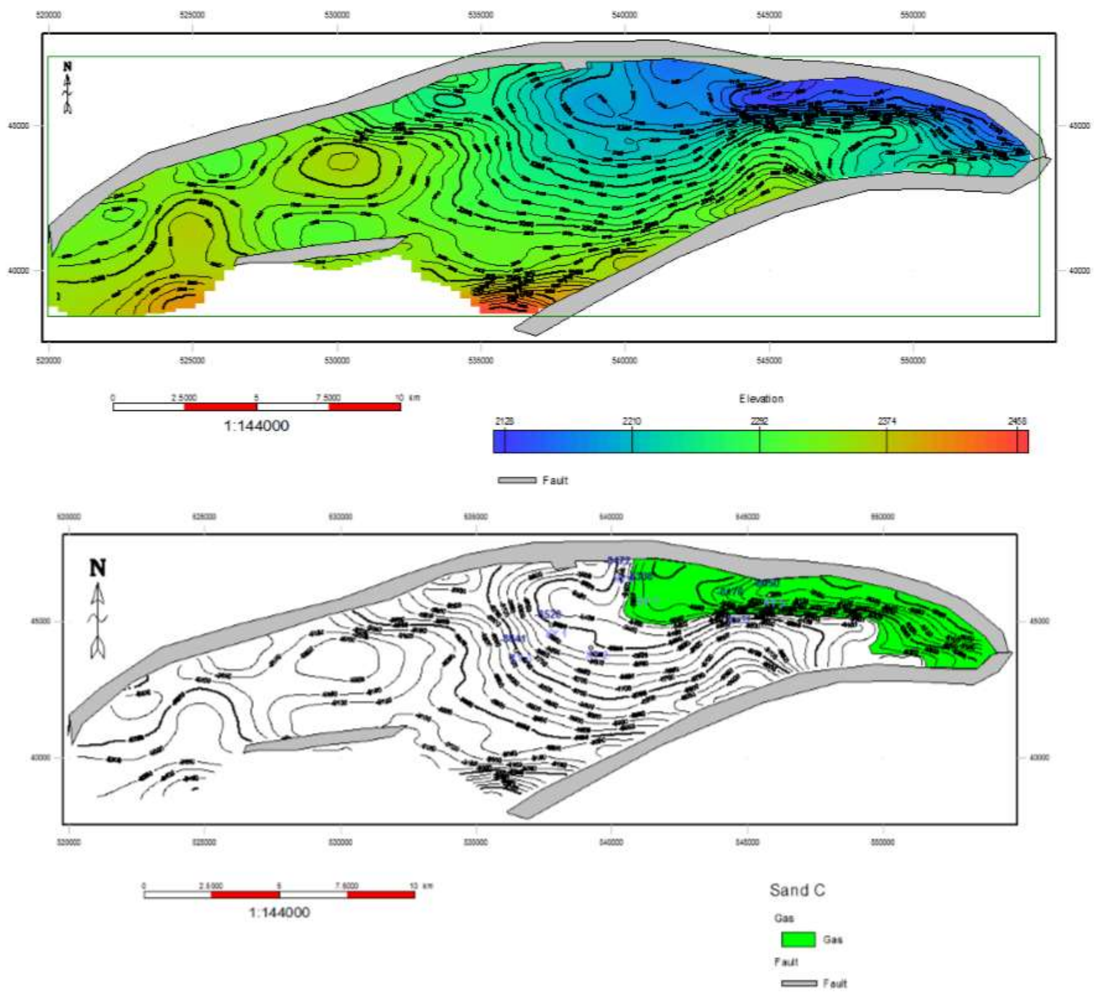

Figure 4.8A.) Isochron map B.) Depth Structure Map of Sand C showing accumulation of gas at the closure between Flt2 and Flt3

4.4 Petrophysical Evaluation

4.4.1 Geologic Description of the Sand intervals

Six reservoirs have been delineated from the non-reservoirs using the GR and Neutron/Density logs. Hydrocarbon accumulation in all the six identified horizons were all controlled by Faults 2 and 3 which were the regional faults in the seismic survey (Fig. 4.5 – 4.8). The reservoirs were penetrated by four wells (AD4, AD5, AD6 and AD7) in the eastern portion of the field (Fig. 4.5 – 4.7). The results from the petrophysical evaluation of the reservoirs showing the tops and bases of the reservoir units and the fluid contacts (GOC, OWC, GDT and ODT) are presented in Table 4.1.

Sand A reservoir is located within a depth range of -7273 ft. to – 7860 ft. and has a gross interval have a thickness of 381.97 ft. in AD4, 173 ft. in AD5, 243 ft. in AD6. The reservoir also has a net pay thickness of 109.49 ft. in AD4, 60 ft. in AD5, 138 ft. in AD6 and 193 ft. in AD7. The net pay thickness was observed to increase from East to West. The Gas Oil Contact (GOC) which represents contact interphase between the oil and gas phase were picked at the depth of -7627 ft. for AD4, -7620 ft. for AD6 and -7630 ft. for AD7. The oil water contact (OWC) which represents the contact interphase between oil and water were identified at the depth of -7667 ft. for AD4, -7656 ft. for AD6 and -7630 ft. for AD7. The reservoir has a Gas Down To (GDT) depth at -7447 ft. in well AD5 as a result of fault compartmentalization. Computed petrophysical logs showing the tops and bases; resistivity and the fluid type for Sand A in wells AD 4, 5 and 6 are presented in Fig. 4.8 - 4.10.

Table 4.1Reservoir depths and fluid contacts across the AD Field (ft.)

Reservoirs	Well	Top MD	Base MD	Gross Interval	Net Res	Net Pay	GOC	OWC	GDT	ODT
Sand A	AD 4	-7477.71	-7859.68	381.97	360.57	109.49	-7627	-7667		
	AD 5	-7272.71	-7446.67	173.96	135.53	59.85			-7447	
	AD 6	-7451.31	-7693.91	242.60	190.21	138.03	-7620	-7656		
	AD 7	-7453.20	-7734.74	281.54	273.48	192.71	-7630	-7661		
Sand B	AD 6	-7777.46	-7840.77	63.32	38.51	19.17				-7840
	AD 7	-7824.06	-7878.87	54.81	53.71	28.84		-7860		
Sand C	AD 6	-8176.21	-8459.57	283.36	211.21	146.53	-8384			
	AD 7	-8308.47	-8624.11	315.65	276.72	43.68	-8384			
Sand D	AD 6	-8497.07	-8740.84	243.77	180.87	75.02	-8617			
	AD 7	-8661.62	-9010.60	348.98	326.07	78.35	-8683	-8752		
Sand E	AD 7	-9202.28	-9342.91	140.64	121.97	106.02	-9299	-9340		
Sand F	AD 7	-9390.83	-9528.34	137.55	116.84	65.18		-9504		

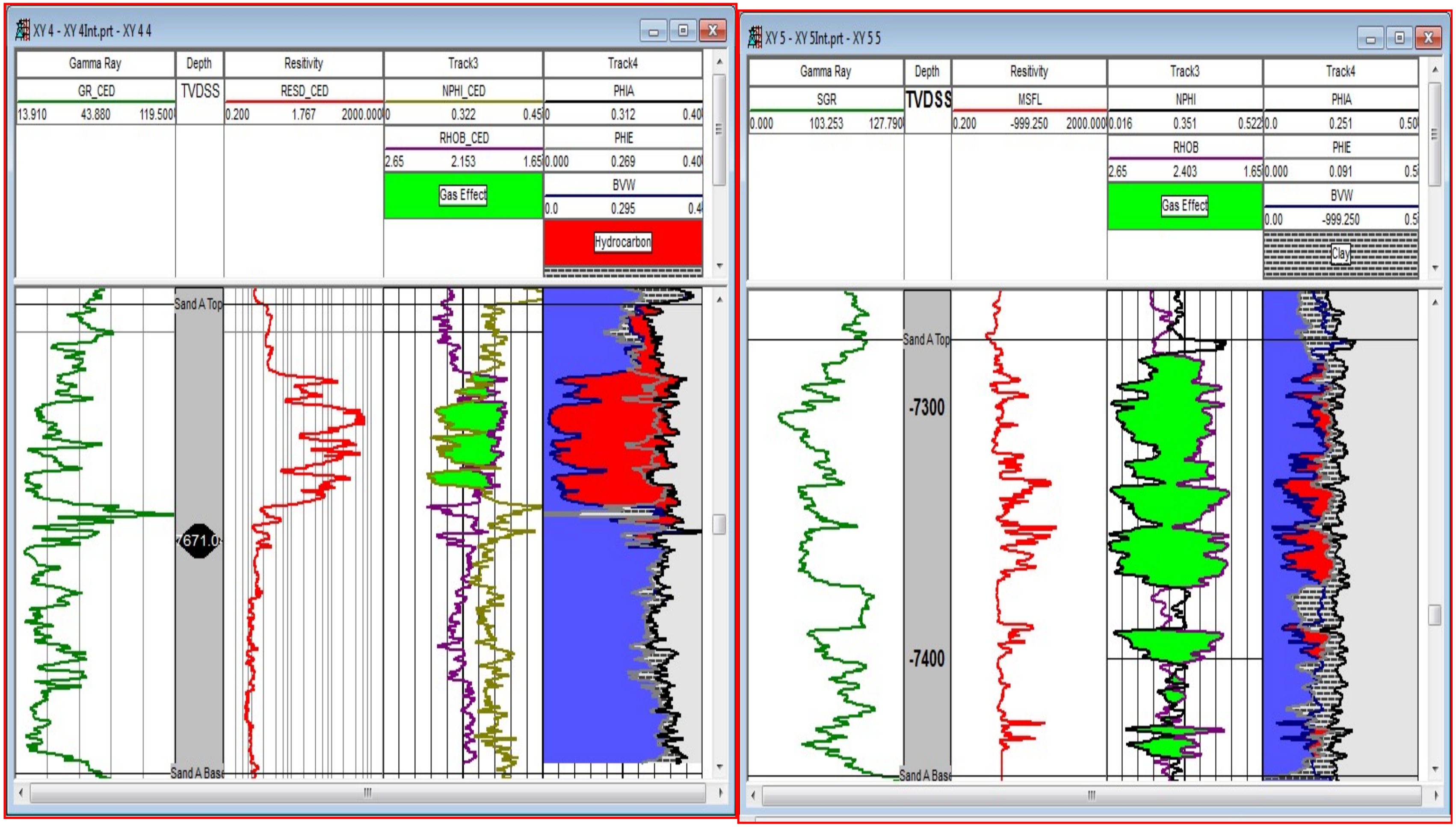

Figure 4.9 Computed petrophysical logs showing the top, base and net pay thickness of Sand A reservoir inwell AD 4, AD 5 and AD6

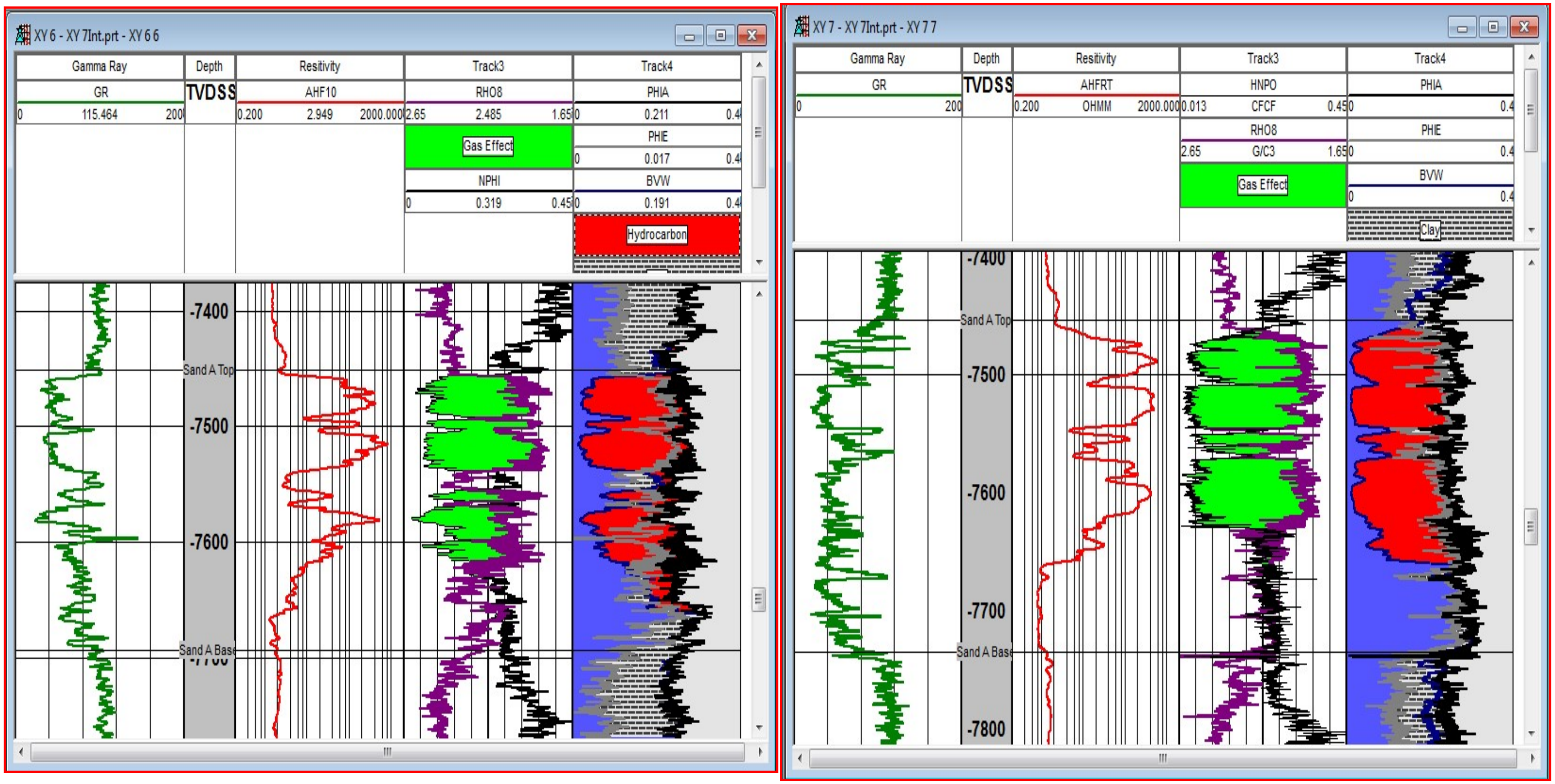

Figure 4.10 Computed petrophysical logs showing the top, base and net pay thickness of Sand A reservoir in well AD6 and AD7

The top and bottom of Sand B reservoir in well AD6 were identified at -7777.46 ft. and -78740.77 ft. respectively with agross interval 63.32 ft. thick and a net pay of 19.17 ft. Oil down to contact (ODT) was identified at a depth of -7860 ft. (Fig. 4.11). whereas, the top and bottom of Sand B reservoir in well AD7 were observed at -7824.06 ft. and -7878.87 ft. respectively with gross interval thickness of 54.81 ft. and net pay of 28.84 ft. oil water contact (OWC) was identified at -7860 ft. depth in well AD7 (Fig. 4.11). The computed petrophysical logs of Neutron/Density curves showing the depths and fluid contacts is presented in Figure 4.11.

Sand C reservoir unit is located within the depth range (top to base) of -8176 ft. to -8560 ft. in AD6 and -8309 ft. to -8624 ft. in AD7 with a gross interval thickness of 283 ft. and 316 ft. in AD6 and AD7 respectively. The reservoir has a net pay thickness of 147 ft. in AD6 and 44 ft. in AD7. Gas Oil Contacts (GOC) was identified at the depth of -8384 ft. in well AD6 and AD7. The computed petrophysical logs of Neutron/Density curves showing the depths and fluid contacts is presented in Figure 4.12.

Sand D reservoir in well AD6 was observed to have a top and base depth of -8497.07 ft. and -8740.84 ft. respectively with agross interval of 243.77 ft. and net pay of 75.02 ft. A gas oil contact (GOC) was identified at the depth of -8617 ft. the Sand A reservoir unit in well AD7 have a gross interval of 348.98 ft. and a net pay of 78.35 ft. with the GOC and OWC and at the depth of -8384 ft. and -8752 ft. respectively. The computed petrophysical logs of Neutron/Density curves showing the depths and fluid contacts is presented in Figure 4.13. Sand E reservoir has agross interval of 140.64 ft. and a net pay of 106.02 ft. with GOC and OWC of -9299 and -9340 ft. respectively in well AD6. Sand F has a gross interval of 137.55 ft. and a net pay of 65.18 ft. with the depth of OWC at -9504 in well AD7. The contacts were considered as part of the uncertainty parameters which feed as input for uncertainty analysis.

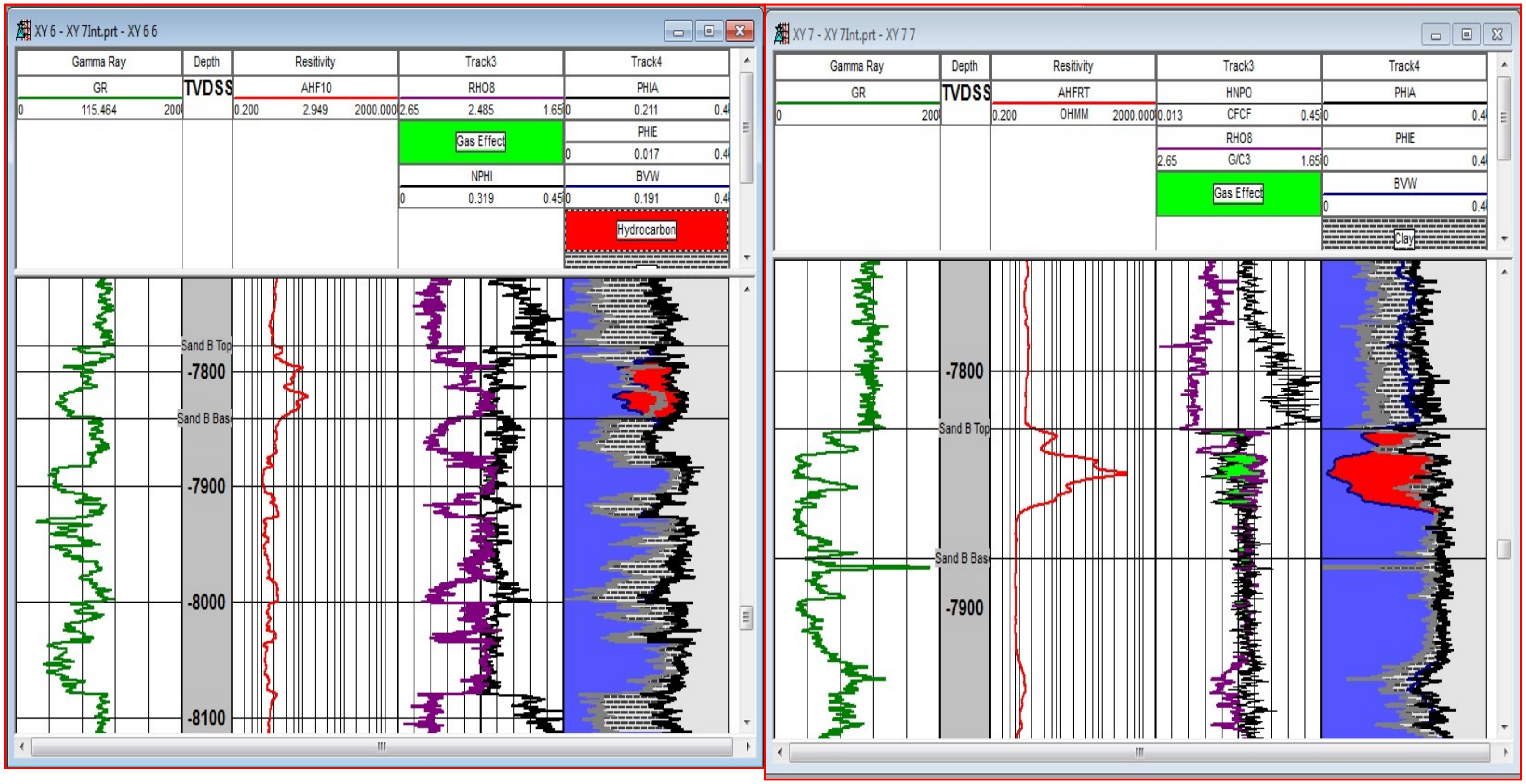

Figure 4.11Computed petrophysical logs showing the top, base and net pay thickness of Sand B reservoir in well AD 6 and AD7

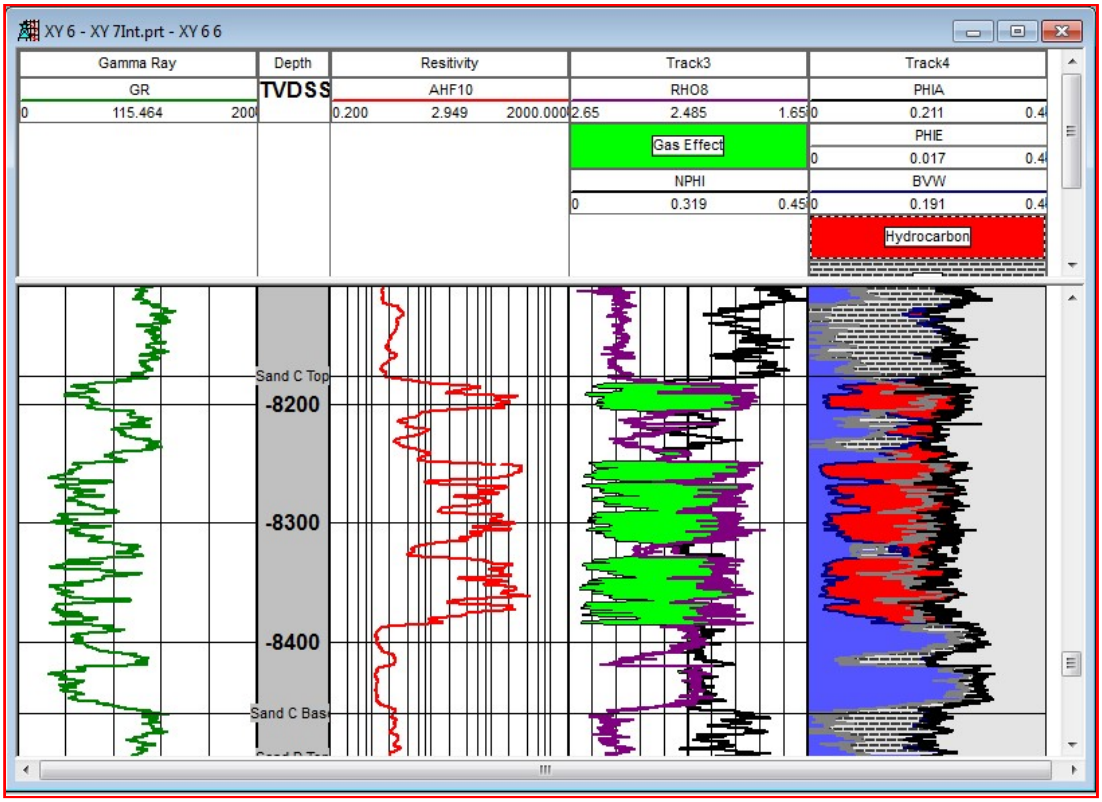

Figure 4.12Computed petrophysical logs showing the top, base and net pay thickness of Sand C reservoir in well AD 6

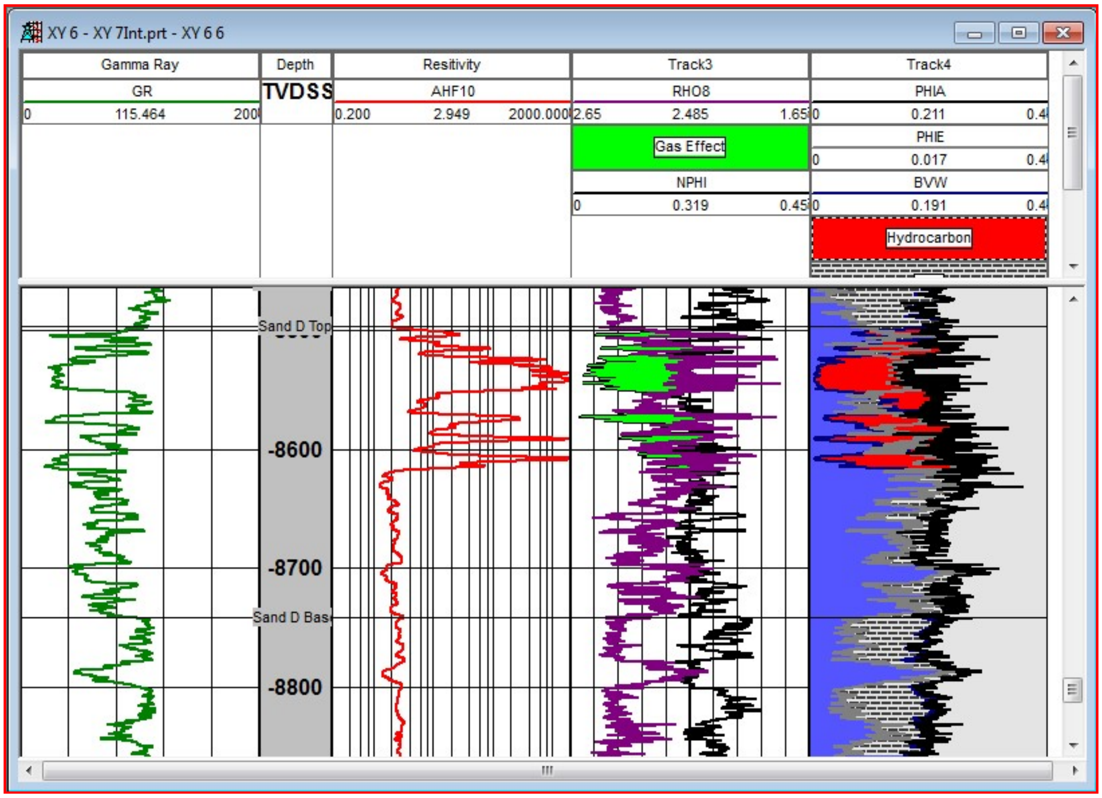

Figure 4.13Computed petrophysical logs showing the top, base and net pay thickness of Sand D reservoir in well AD 6

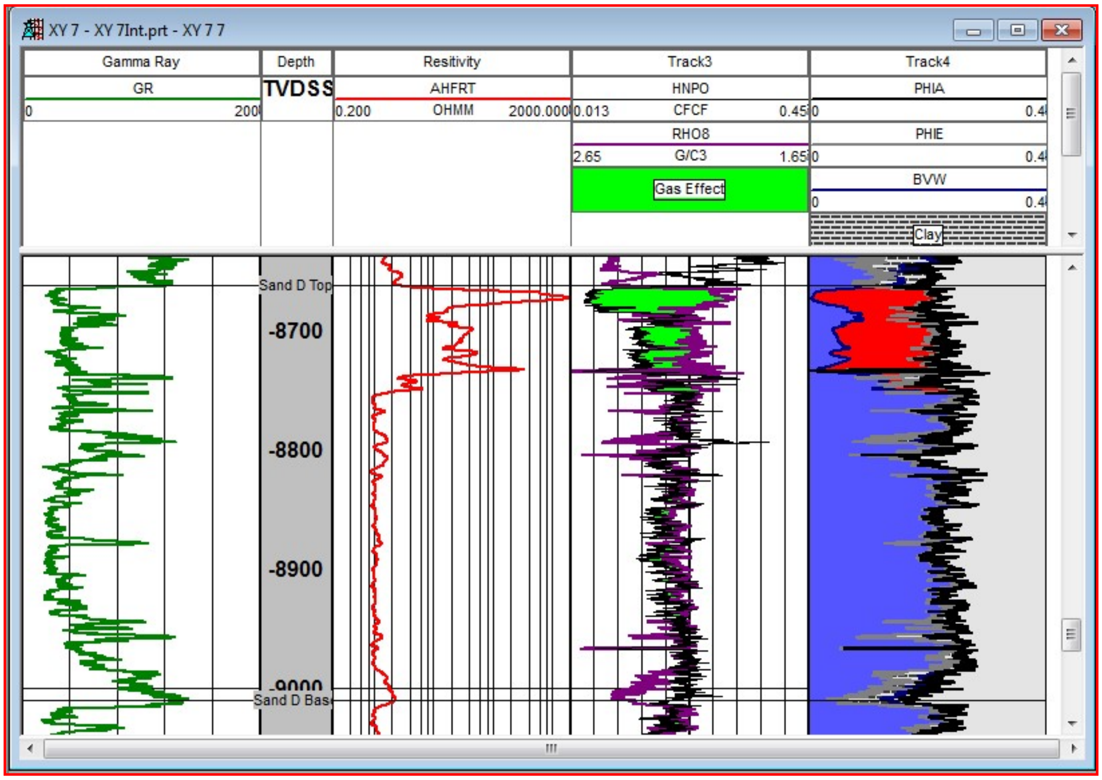

Figure 4.14Computed petrophysical logs showing the top, base and net pay thickness of Sand D reservoir in well AD 7

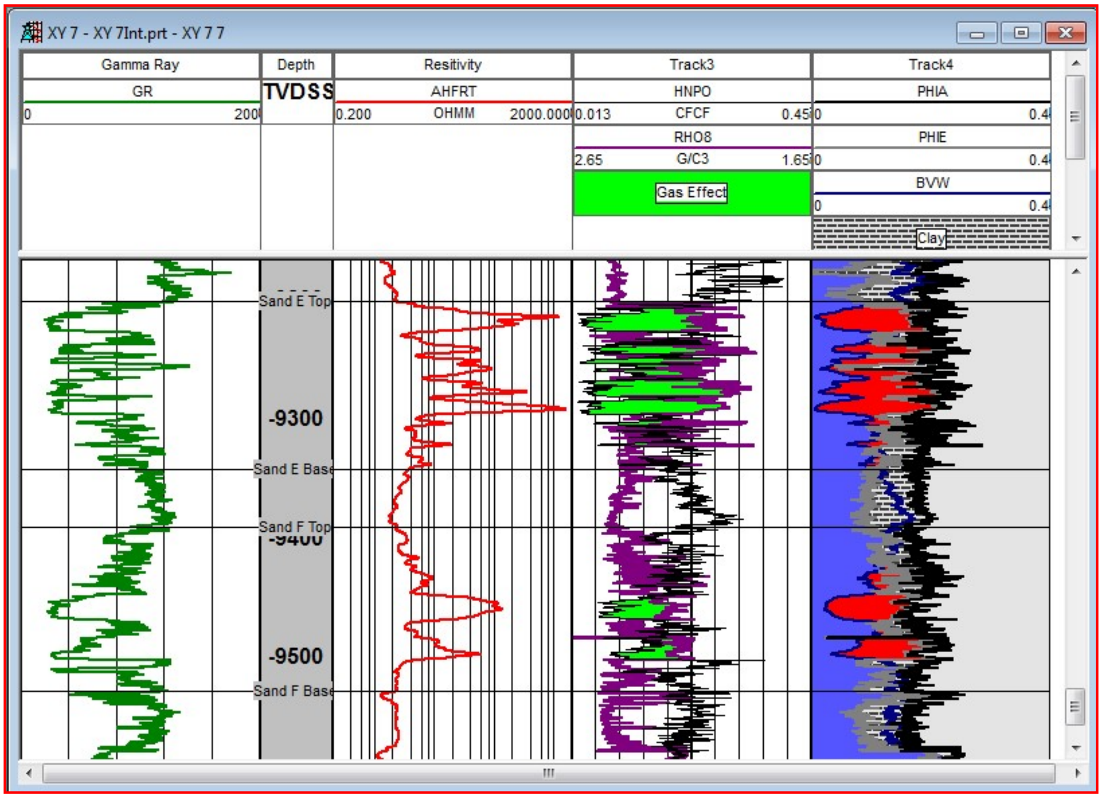

Figure 4.15Computed petrophysical logs showing the top, base and net pay thickness of Sand E and F reservoirs in well AD 6

4.5 Reservoir Properties of AD Field

The pay summary of the reservoirs, especially porosity, permeability and Net to Gross in the AD Field is presented in Table 4.2. The Net to Gross ratio (NTG) ranges between 0.79 and 0.87, while the porosity values are from 20% to 28% and can be quantitatively evaluated as very good (Etu-Efeotor, 1997). These values are similar with that reported for Niger Delta which ranges from 15 to 40% in the reservoir rocks.. Edwards and Santogrossi (1990) proposed for 40% for primary Niger Delta Miocene paralic sandstones reservoirs.

The computed porosity of the reservoirs (Sand A to Sand F) vary between 0.19 and 0.28 (avg. 0.29) indicating a good to excellent reservoir characteristics (Etu-Efeotor, 1997). The reservoir characteristics of the sand intervals were observed to reduce with depth. Sand A and Sand B have porosity of 26% and 28% respectively while the deeper reservoirs Sand C, Sand D, Sand E and Sand F show a decreasing trend and values of 24%, 22%, 21% and 20% respectively. The thickness of the reservoirs vary laterally and together with the GRV and are controlled by the growth faultsthe net pay thickness across the field with depths between 59ft and 192ft (avg. 125ft). The GRV for gas and oil in the entire field was computed as 266.33 (acre foot)and 180.21 (acre foot)respectively.

The water saturation (Sw) in the field ranges from 0.19 to 0.39 with Sand A (0.19) having the lowest volume of pore spaces containing water (Table 4.2). The total STOIIP and GIIP from the field was estimated at 565 MMbbl and 4.08 TCF respectively (Table 4.2) where Sand A was observed to be the most economically viable with 39% of the STOIIP and 46% of GIIP in the AD Field (Figure 4.16 – 4.17).

Table 4.2 Pay summary for the reservoirs in the AD Field

		GRV	NTG	Porosity	Sw	HIIP
Sand A	Gas	1,090,418.00	0.87	0.26	0.19	1,934,125,248,829.62
	Oil	214,732.00	0.87	0.26	0.19	223,234,004.55
Sand B	Gas					-
	Oil	78,008.00	0.79	0.28	0.39	60,437,062.75
Sand C	Gas	789,116.00	0.81	0.24	0.26	1,101,657,265,116.15
	Oil		0.81	0.23	0.25	-
Sand D	Gas	379,110.00	0.84	0.22	0.24	525,506,677,680.41
	Oil	163,707.00	0.84	0.22	0.24	133,000,185.67
Sand E	Gas	420,400.00	0.87	0.21	0.29	524,338,388,110.90
	Oil	91,574.00	0.87	0.21	0.29	66,941,144.09
Sand F	Gas	176,352.20	0.85	0.20	0.37	178,064,644,059.91
	Oil	138,979.80	0.85	0.20	0.37	82,247,081.26
	Gas					**4,085,627,579,737.07**
	Oil					**565,859,478.31**

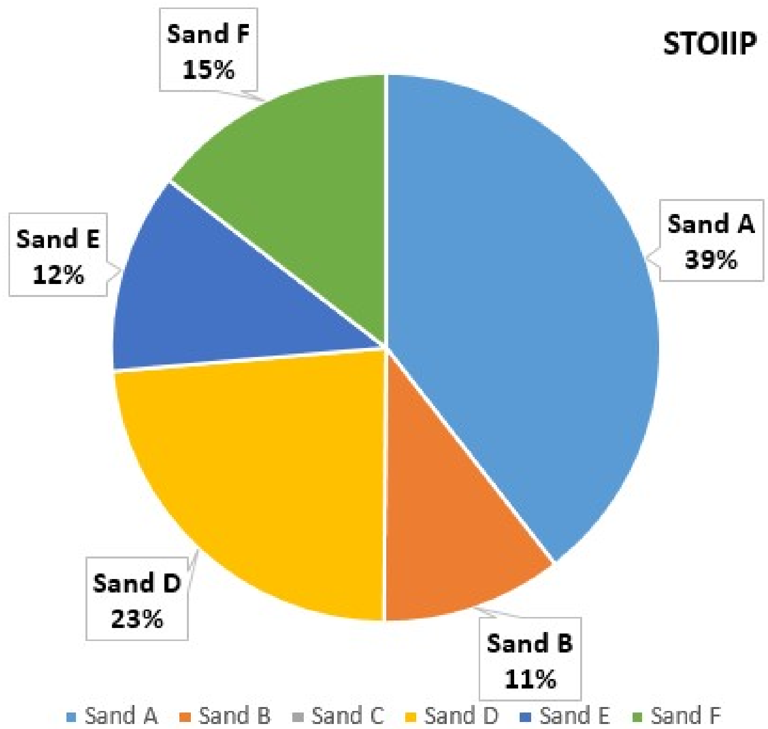

Figure 4.16Pie chart showing the percentages of STOIIP in the reservoirs

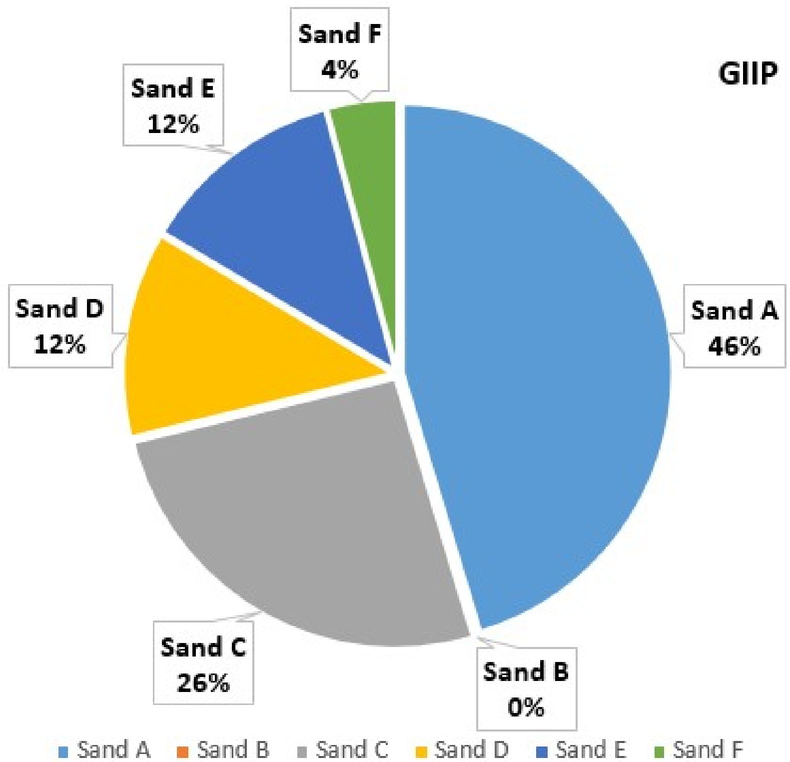

Figure 4.17Pie chart showing the percentages of GIIP in the reservoirs

4.6 Static Reservoir Modelling

The static reservoir model of Sand A, which is the sand interval with the highest hydrocarbon potential was developed to give a fair reality of the subsurface. The Sand A reservoir was used because it cuts across all the wells in the survey.

4.6.1 Porosity Model of Sand A

A 3D porosity model showing the porosity distribution in the Sand A reservoir is presented in Figure 4.18. The model shows the porosity within the reservoir is well distributed and ranges from 0.10 to 0.42. However about 90% of the reservoir have porosity ranging between 0.20 and 0.42 which indicates good to excellent porosity (pore spaces) capable of retaining hydrocarbon. Wells in the eastern portion (AD4, AD5, AD6 and AD7) have very good reservoir characteristics with average porosity varying between 0.26 and 0.32 (Figure 4.18).

4.6.2 WaterSaturation Model

The water saturation model for Sand A reservoir shows that the S_w in the field varies from 0.2 to 0.9 (Figure 4.19). The south-eastern part of the field was observed to have water saturation values greater than 0.75 which indicates high accumulation of water. However, the north-eastern part of the model (Figure 4.19) shows grids of water saturation with values between 0.2 and 0.5, indicative of hydrocarbon zones in the reservoir. The hydrocarbon producing wells in the Field (AD4, AD5, AD6 and AD7) were situated in this part of the model (Figure 4.19).

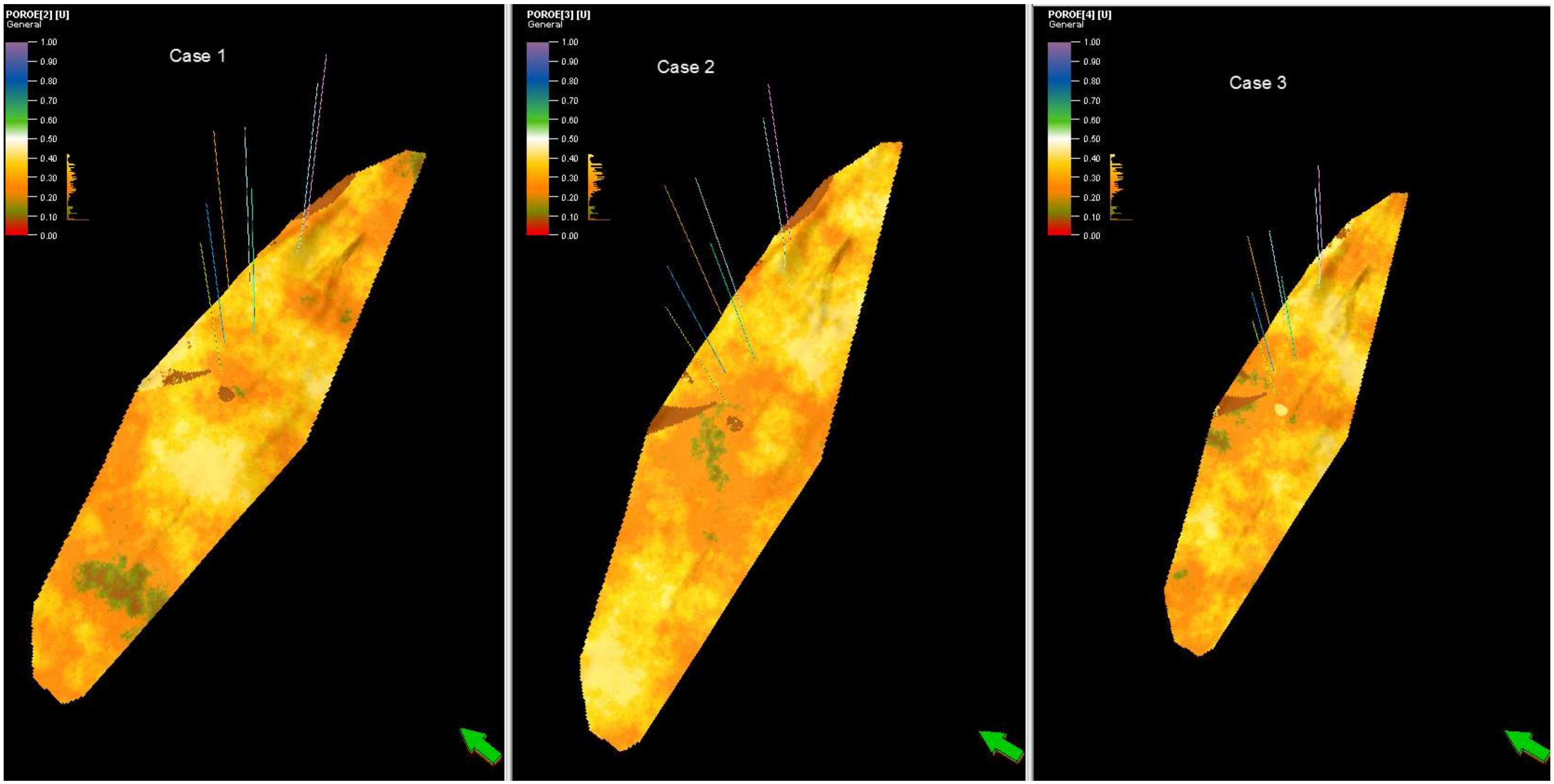

Figure 4.18 Porosity Model for Sand A showing the distribution of the wells

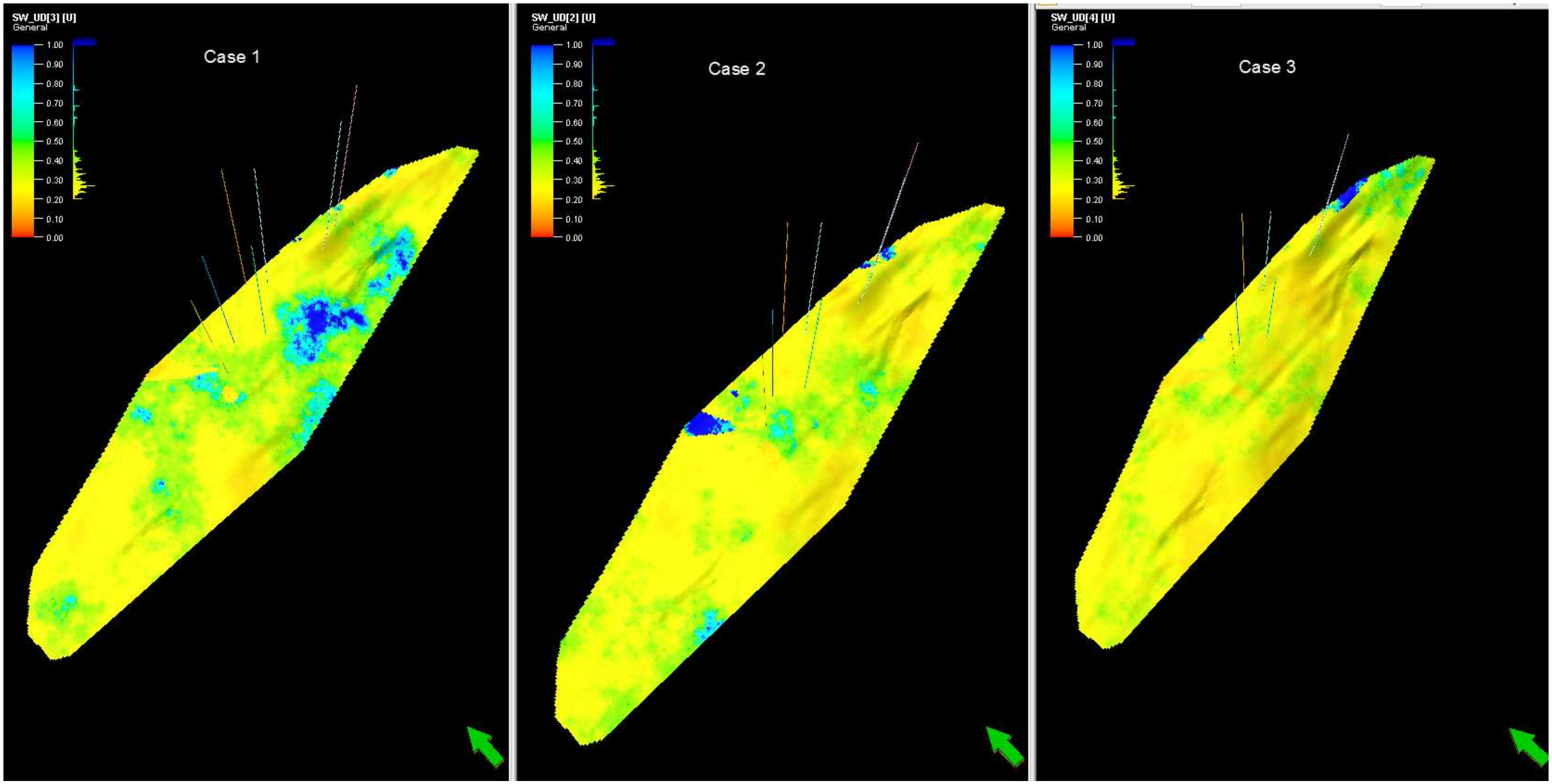

Figure 4.19 The trend of water saturation in the reservoir showing the distribution of the wells

4.6.3 Facie Model

The facie model of Sand A reservoir (Figure 4.20) shows that all the facies present consist of shale (30%), fine sand (60%) and coarse sands (10%). The facies show a regional distribution pattern of sediment with a North – South orientation. The abundance of shale (30%) in the reservoir indicates a transgressive marine environment with a slight influence of tides (Adeoti *et al., 2014*). Sand A has more good facies (fine and coarse sands) for hydrocarbon accumulation.

4.6.4 Reservoir Volumetric

The volumetric estimates after modelling Sand A reservoir is presented in Table 4.3. This shows that the sand interval have a gross thickness ranging between 173 ft. and 381 ft. across the survey (Figure 4.21). The reservoir has a total pore volume of 2,343 (10^6 RB) with 9% Hydrocarbon Pore Volume (HCPV) oil of 209 *10^6 RB and 56% Hydrocarbon Pore Volume (HCPV) gas of 1,314 *10^6 RB. The reservoir has a STOIIP of 175 * 10^6 STB and GIIP of 438,096 * 10^6 MSCF which indicates that the hydrocarbon in Sand A is of commercial value and the static model derived from it could be used for simulation and monitoring performance.

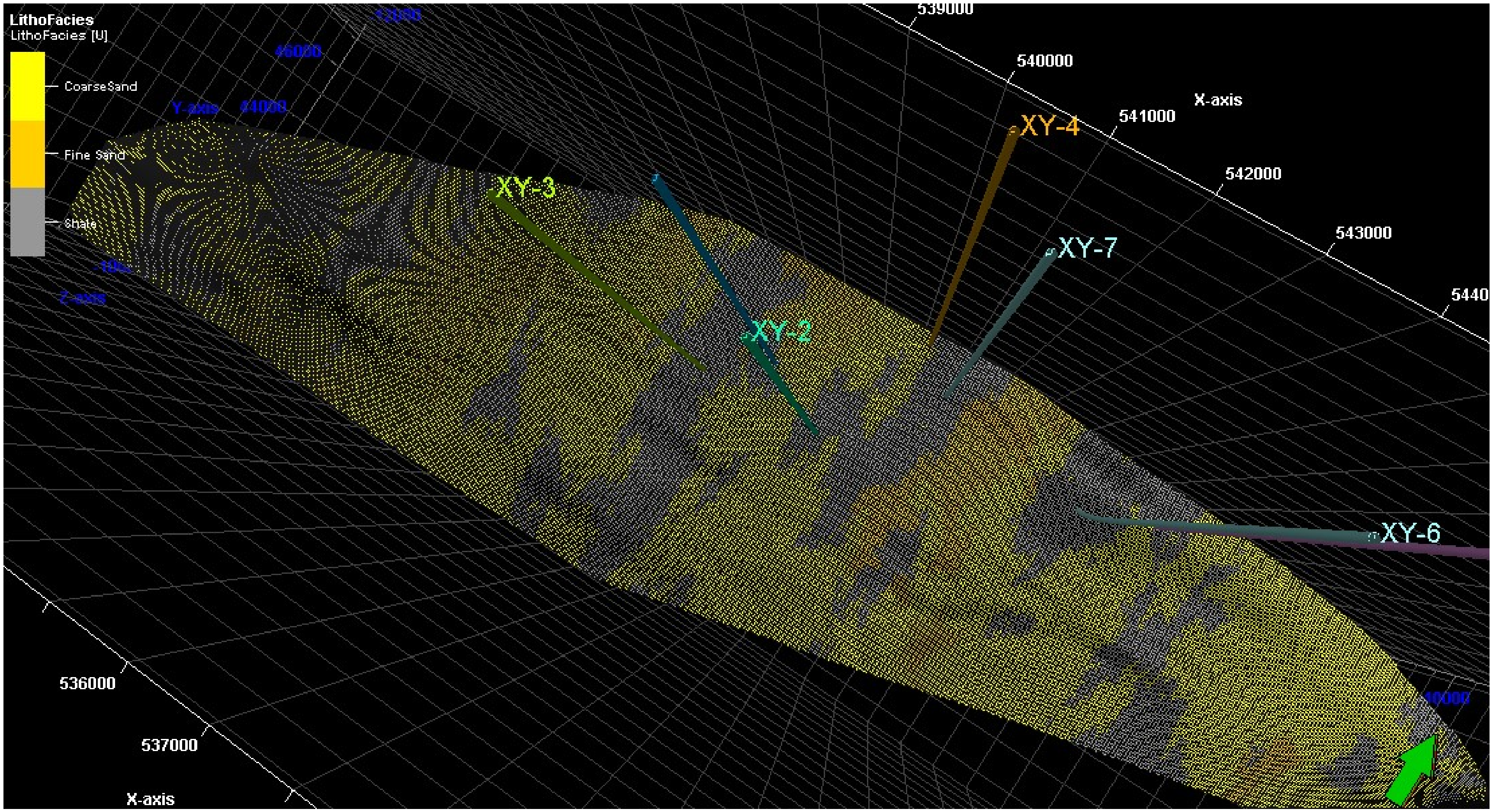

Figure 4.20 Facie Model for Sand A reservoir showing the distribution of coarse sand, fine sand and shale

Table 4.3Volumetric estimate obtained from Sand A after modeling

	Zone 1
Bo (formation Vol. factor)	1.2
Recovery factor	0.35
Pore volume [10^6RB]	2,343
HCPV oil [10^6 RB]	209
HCPV gas [10^6 RB]	1,314
STOIIP (in oil) [10^6 STB]	175
GIIP (in gas)[10^6 MSCF]	438,096
Recoverable oil[*10^6 STB]	61
Recoverable gas[*10^6 MSCF]	306,667

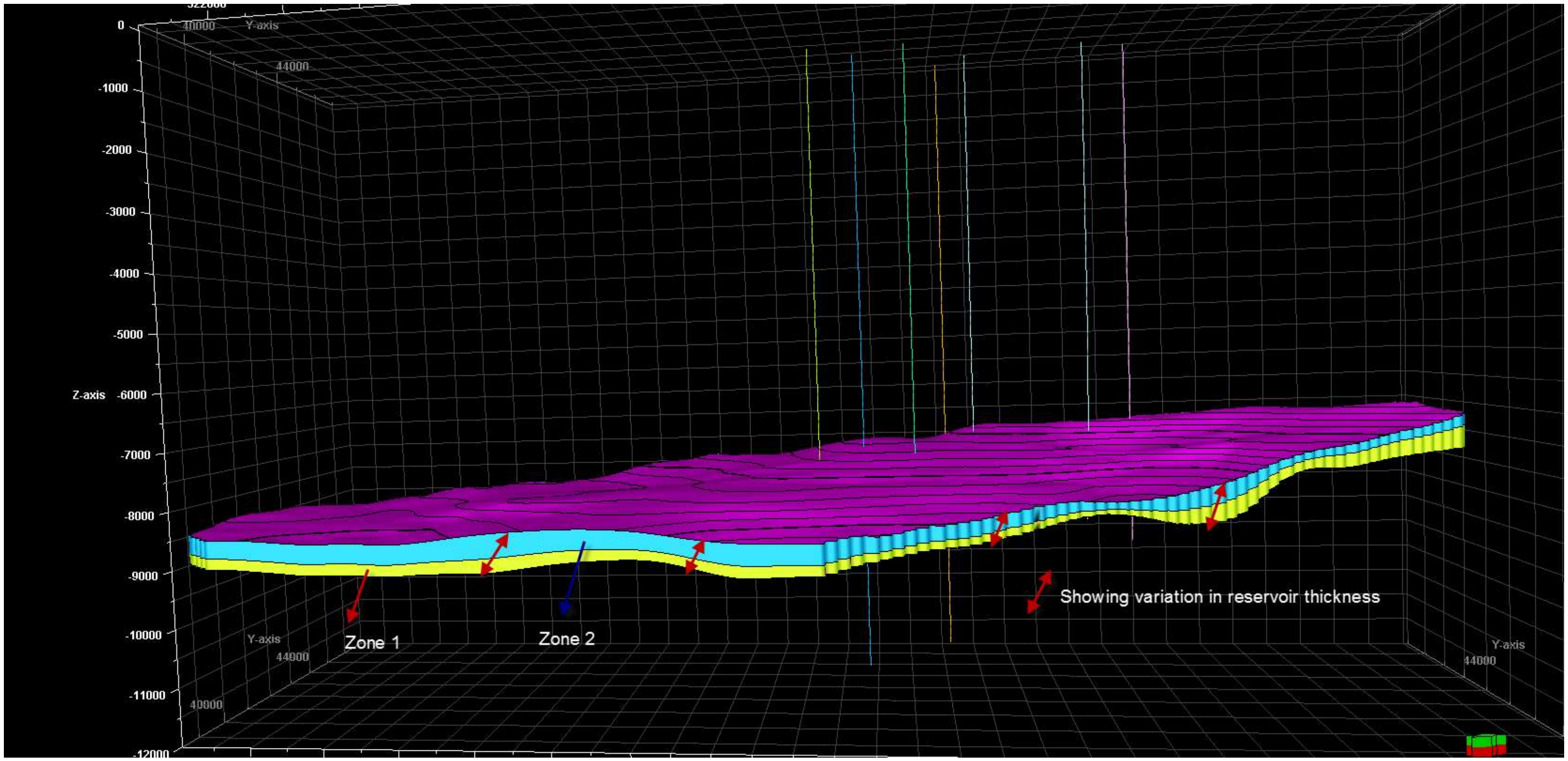

Figure 4.21Structural and stratigraphic modeling of Sand A

4.6.5 Uncertainty Analysis

A table showing the normally distributed geologic input parameters (saturation (S_w), Porosity (φ), NTG and GRV) used for Monte Carlo simulation is presented in Table 4.4.The influence of these geologic parameters were identified and quantified on the STOIIP, GIIP and Reserve estimate using deterministic values (Table 4.4) and the simulation results are presented in Appendix I-XII.

A summary result of the simulation exercise is presented in Table 4.5.The average STOIIP values in Sand A, B, D, E and F reservoirs are 213.97 MMbbl, 64.14 MMbbl, 132.75 MMbbl, 66.96 MMbbl and 82.38 MMbbl respectively. The coefficient of variation of these values ranged from 9 to 14 showing that the uncertainty of the STOIIP values is low. The summary result also show the P10, P50 and P90 values of the total oil reserve in AD Field as 180 MMbbl, 165.8 MMbbl and 205 MMbbl respectively (Table 4.7).

The GIIP values in Sand A, C, D, E and F reservoirs are 1.85 TCF, 1.29 TCF, 0.52 TCF, 0.52 TCF and 0.17 TCF respectively. The coefficient of variation of the GIIP values ranged from 9 to 11 showing that the uncertainty of the GIIP values is also low. The summary result also show the P10, P50 and P90 values of the total GIIP in AD Field as 3.52 TCF, 4.02 TCF and 4.56 TCF (Table 4.8).

Table 4.4Deterministic values used for Monte Carlo Simulation

	Sand A			Sand B			Sand C		
	Low	**Ave**	**High**	**Low**	**Ave**	**High**	**Low**	**Ave**	**High**
GRV	193,258.80	214,732.00	236,205.20	70,207.20	78,008.00	85,808.80			
NTG	0.78	0.88	0.97	0.61	0.79	0.98	0.75	0.81	0.88
Porosity	0.25	0.28	0.32	0.26	0.29	0.31	0.21	0.24	0.26
So	0.59	0.71	0.83	0.49	0.61	0.73	0.66	0.73	0.80
Bo	1.23	1.37	1.50	1.23	1.37	1.50	1.23	1.37	1.50
RF	0.20	0.30	0.40	0.20	0.30	0.40	0.20	0.30	0.40

	Sand D			Sand E			Sand F		
	Low	**Ave**	**High**	**Low**	**Ave**	**High**	**Low**	**Ave**	**High**
GRV	147,336.30	163,707.00	180,077.70	82,416.60	91,574.00	100,731.40	125,081.82	138,979.80	152,877.78
NTG	0.74	0.84	0.93	0.78	0.87	0.95	0.76	0.85	0.93
Porosity	0.20	0.23	0.25	0.19	0.21	0.23	0.18	0.20	0.21
So	0.68	0.75	0.83	0.64	0.71	0.78	0.57	0.63	0.69
Bo	1.23	1.37	1.50	1.23	1.37	1.50	1.23	1.37	1.50
RF	0.20	0.30	0.40	0.20	0.30	0.40	0.20	0.30	0.40

Table 4.5Summary of simulated results for STOIIP, GIIP and Reserve estimates in the AD Field

	Sand A	Sand B	Sand D	Sand E	Sand F	Total
STOIIP (MMbbl)						
	Sand A	**Sand B**	**Sand D**	**Sand E**	**Sand F**	**Total**
P10	183.31	50.33	116.69	59.2	72.89	482.42
P50	213.04	60.86	132.26	66.73	82.11	555
P90	246.21	73.16	149.45	74.88	92.11	635.81
Deterministic	223.23	60.4	133	66.94	82.24	
Mean	213.97	61.41	132.75	66.96	82.38	
Standard Dev.	24.29	8.83	12.63	6.14	7.54	
C. of Variation (%)	11	14	10	9	9	
Oil Reserve (MMbbl)						
	Sand A	**Sand B**	**Sand D**	**Sand E**	**Sand F**	**Total**
P10	49.86	13.87	31.37	15.56	19.55	130.5
P50	63.58	18.17	39.53	19.94	24.57	165.8
P90	79.14	23.21	48.67	24.44	30.07	205.54
Mean	64.18	18.42	39.82	20.09	24.72	
Standard Dev.	11.37	3.65	6.63	3.31	4.07	
C. of Variation (%)	18	20	17	16	16	
GIIP (TCF)						
	Sand A	**Sand C**	**Sand D**	**Sand E**	**Sand F**	**Total**
P10	1.59	1.15	0.46	0.16	0.16	3.52
P50	1.85	1.29	0.52	0.18	0.18	4.02
P90	2.13	1.44	0.59	0.2	0.2	4.56
Deterministic	1.9	1.1	0.52	0.52	0.18	4.22
Mean	1.85	1.29	0.52	0.52	0.17	
Standard Dev.	0.21	0.14	0.05	0.05	0.02	
C. of Variation (%)	11	9	9	9	9	
Gas Reserve (TCF)						
	Sand A	**Sand C**	**Sand D**	**Sand E**	**Sand F**	**Total**
P10	1.17	0.84	0.34	0.34	0.12	2.81
P50	1.38	0.96	1.38	0.39	0.13	4.25
P90	1.62	1.10	1.39	0.45	0.15	4.72
Mean	1.39	0.97	1.39	0.39	0.13	
Standard Dev.	0.18	0.10	0.18	0.04	0.01	
C. of Variation (%)	13	10	13	11	11	

4.6.6 Sensitivity Analysis

Tornado charts showing the regression coefficient and influence of the geological parameters on the STOIIP and GIIP values are graphically displayed in Figures 4.22 & 4.23. The result of the Sensitivity analysis on the STOIIP values are displayed as Tornado charts in Figure 4.22. The bars on the charts represent the regression coefficient of geologic parameters. The charts show that water saturation (62%) and porosity (42%) are the geological parameters with the greatest influence on Sand A reservoir. NTG (66%) and Sw (54%) are the prominent parameters for Sand B reservoir, while NTG (49%) has the greatest influence on the STOIIP values estimated for Sand D reservoir.

The results of the sensitivity analysis carried out on the GIIP values as presented in Figure 4.23 shows that So (63%), porosity (43%), NTG (40%) and GRV (36%) are the geologic parameters with prominent influence on the GIIP values of Sand A which have the greatest gas reserve in the field.

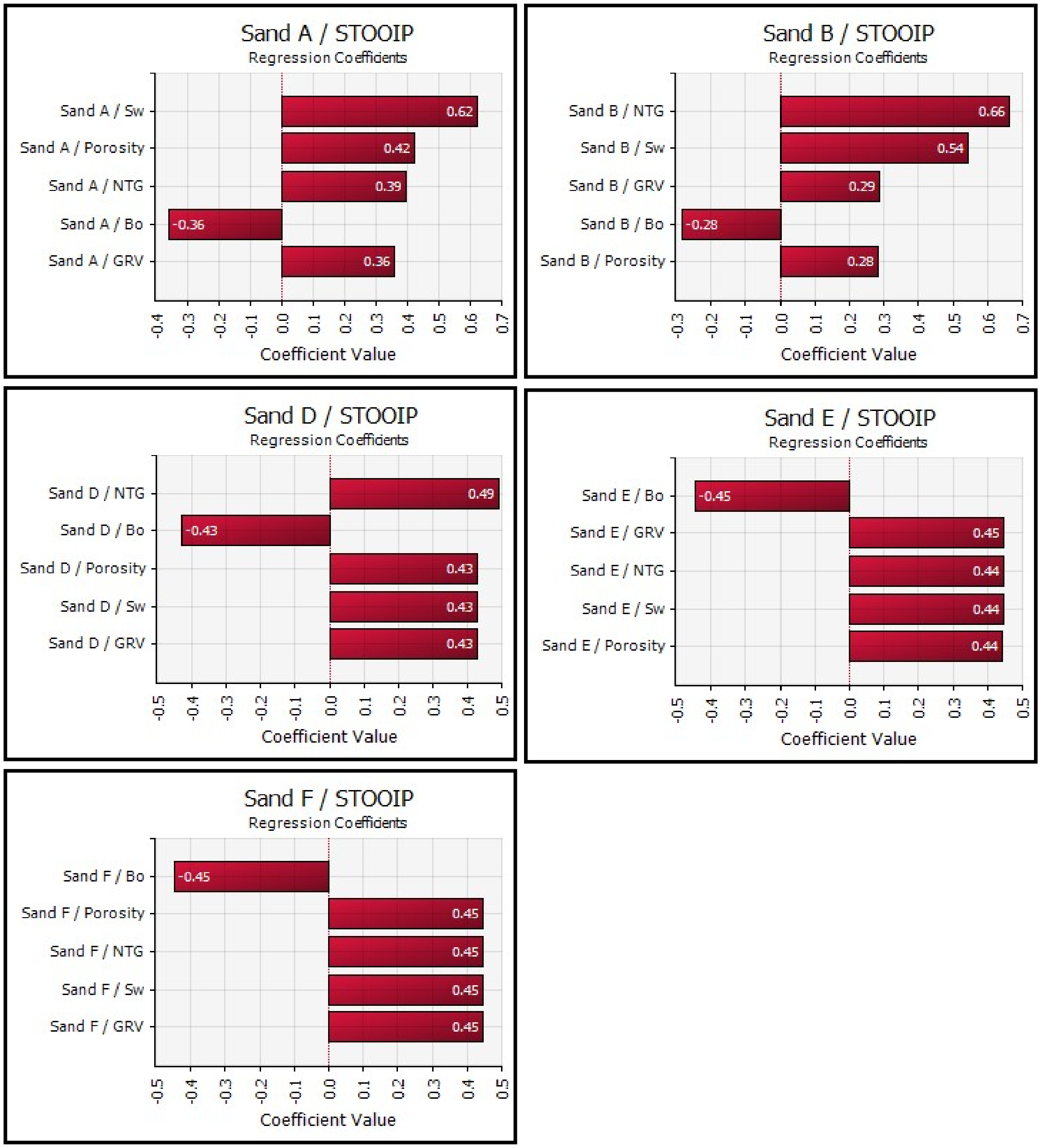

Figure 4.22 Tornado Charts graphically showing the sensitivity of geological parameter on the STOIIP values.

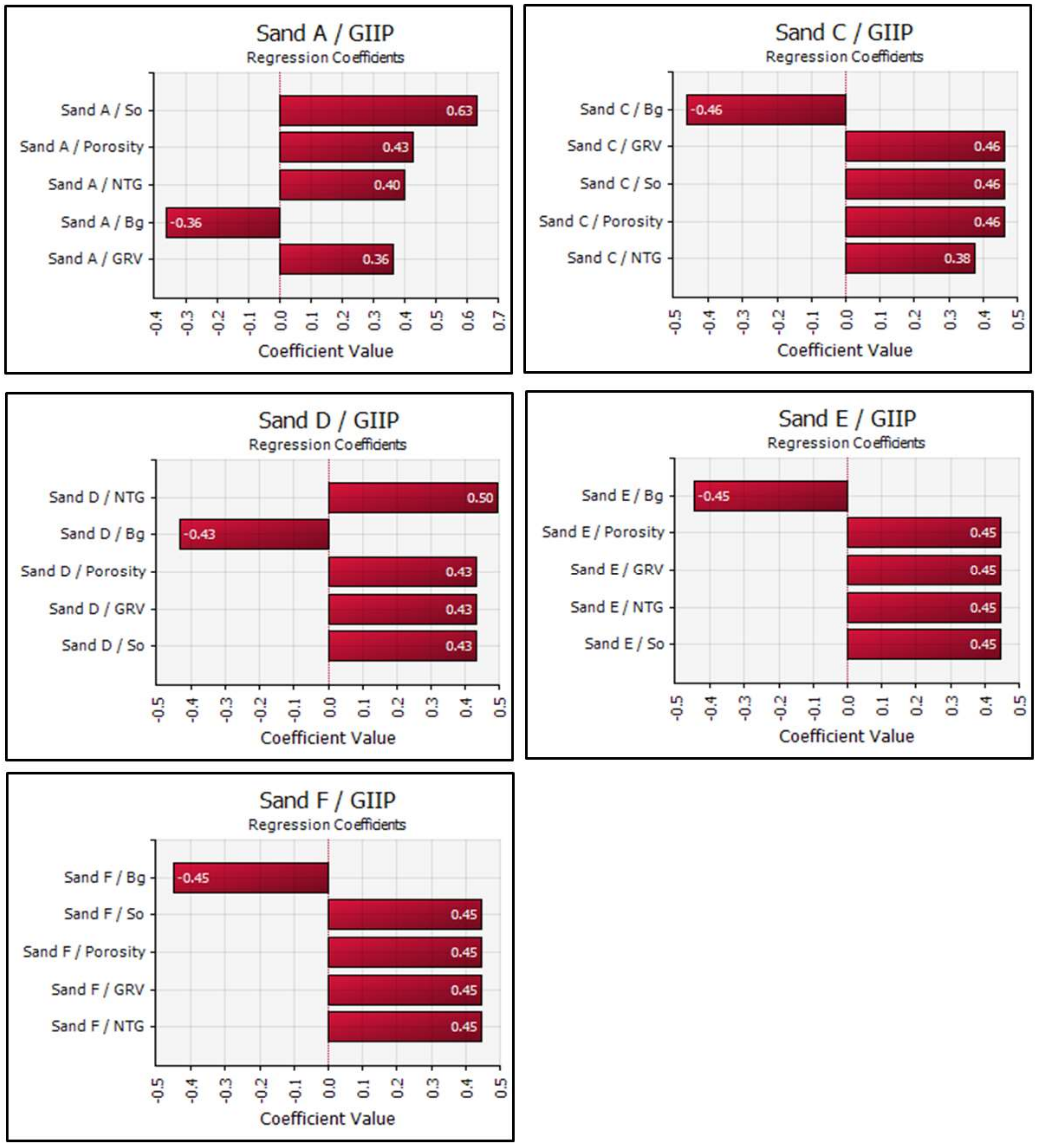

Figure 4.23Tornado Chars graphically showing the sensitivity of geological parameter on the GIIP values.

CHAPTER FIVE

5.0 Summary and Conclusion

Sixteen faults labelled Flt 1 to Flt 16 were identified and mapped across the survey during seismic interpretation. Two major faults (Flt 1 and Flt 2) were identified as the major structure building faults responsible for inducing a major structural trap (fault induced closure) at the western part of the survey. The fault closure is responsible for the accumulation of hydrocarbon in the field. The faults observed in the study are predominantly listric normal faults which extensional regimes peculiar with the Niger Delta Basin. Six horizons were identified and were labelled Sand A, Sand B, Sand C, Sand D, Sand E and Sand F. The horizons were confirmed to have accumulation of hydrocarbon in the wells within structural closure aided by the major faults on the eastern part of the survey, while the wells in the western part of the survey were observed to be dry.

The hydrocarbon resource in AD Field, Niger Delta of Nigeria was evaluated by calculating the Hydrocarbon initially in place using both deterministic and stochastic techniques. The stochastic evaluation was carried out by subjecting the geological parameters to Monte Carlo simulation in order to identify the P10, P50 and P90 values for the reservoirs in the field. Sensitivity analysis was carried out to quantify the influence of the petrophysical parameters on the HIIP. The result of the volumetric estimate from the reservoirs shows that the STOIIP is 565 MMbbl and GIIP of 4.09 TCF. The volumetric estimate derived from the Monte Carlo simulation using the Latin hypercube algorithm for sampling shows that the P10, P50 and P90 probabilistic values for the STOIIP are 482 MMbbl, 554 MMbbl and 482 MMbbl respectively and 4,945 TCF.

. The Sensitivity analysis showed that porosity, GRV, NTG and S_w all have an increasing order effect on the reserve estimate of the sand intervals, this is shown by the low coefficient of variation which ranges from 9% to 14% showing low uncertainty for the values estimated.

The drilling of more wells will enhance the optimization of the field especially on the eastern portion of the survey. A gas monetization plan is necessary before the commencement of production because of the Field's huge gas reserve. Sand A should be given preference during the development of the field because of its huge HIIP estimates.

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