EVALUATION OF PETROPHYSICAL PROPERTIES IN THE AK FIELD OF THE NIGER DELTA PROVINCE OF NIGERIA USING INTEGRATED DATA

By

Philip D. Samuels

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Prof. Dr. K. Mosto Onuoha

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BY:

PHILIP D. SAMUELS

RECOMMENDED BY:

Professor K. Mosto Onuoha

[Thesis Supervisor]

Professor Godwin Chukwu

[Committee Member]

Dr. Mukhtar Abdulkadir

[Committee Member]

APPROVED BY:

Professor Godwin Chukwu

[Head, Petroleum Engineering Department]

Professor Wole Soboyejo

[Provost]

[Date]

DEDICATION

This thesis is dedicated to my **deceased parents** and the **General Auditing Commission, Republic of Liberia,** respectively for their evergreen motivations which continue to rekindle the aspiration for the attainment of higher education and for its supportive role in encouraging and promoting academic diversification as foundation for addressing transparency and accountability in Liberia.

ACKNOWLEDGMENT

Contributions from many sources culminated into the writing and submission of this thesis for which I am very grateful. Against this background, I am immeasurably indebted to my thesis supervisor, **Prof. Dr. K. Mosto Onuoha** whose guidance landed me on the platform of presentation. Also, it is with great honor that I accord my thesis committee members their due recognition for their immense contributions. Without them, this work would not have been certified. To this end, special acknowledgement goes out to **Prof. Dr. Godwin A. Chukwu** and **Dr. Mukhtar Abdulkadir** for their inputs and directions.

The contribution of the entire faculty of the Petroleum Engineering Department is herein acknowledged as their lecture materials were valuable assets in obtaining supportive information. Recognition is also accorded Messr. **Chidozie I. P. Dim** and **Nnebedum Okechukwu** of the **University of Nigeria, Nsukka** and **Mr. Haruna Onuh** of the **African University of Science and Technology, Abuja** for their enormous contributions on the software applications part of this research.

The impetus to carry out this research was drawn from the need to predict a field's performance by data integration. Combining seismic and well data, this work was stimulated by the need to develop models which would enable the estimation of reservoir parameters using the appropriate software.

To reach this stage in my pursuit of higher education, institutional and relational supports cannot be denied. In this vein, I extend many thanks to the **General Auditing Commission of the Republic of Liberia** for its continued support during the course of my studies. And remembering the prolonged patience endured by my wife and kids during the time of my absence

from home, hats-off goes out to them. My wife most especially was a constant source of moral support and encouragement.

Finally, for the many who the limitation of space cannot allow to be named in person, I seize this opportunity to extend my heartfelt congratulations.

ABSTRACT

The AK field is an oil field draining the Agbada Formation, one of the three units of the Niger Delta Province, which started forming about 50 million years ago. Reservoirs from the AK field are sandstones and are located in the central offshore area of the Niger Delta. The sedimentary basin consists of thick succession of non-marine and shallow marine deposits.

Reservoir modeling is often associated with uncertainties that lead to inadequate description of the reservoir and inappropriate prediction of field performance. Various techniques are being developed to reliably predict reservoir properties for appropriate reservoir characterization and field performance respectively. The reliability with which this can be achieved is tied to validating the data acquired from one method of investigation with another. Amongst the various methods are seismic inversion and well integration.

The case study for this research is the AK field of the Niger Delta Province. Well log data for thirteen (13) wells and seismic volume spanning the field are collected and analyzed to predict water saturation, porosity, permeability, shale volume and net-to-gross sand distribution. The analysis was performed using **Schlumberger-Petrel** software. Multiple inter-wells data sets acquired from well logs and seismic survey from the field were tied together to estimate petrophysical properties.

A Geological model comprising structural and stratigraphic framework for the AK field strata was constructed by combining data from 13 well logs and a seismic volume spanning the areal extent of the field. The property distribution within the reservoir was achieved by employing geostatistics - Sequential Gaussian Simulation (SGS), Variogram and trend maps.

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CHAPTER 1

INTRODUCTION

1.1 <u>Background and Rationale</u>

The acquisition and handling of data play significant roles in petroleum exploration and production. How these data can be tied together is vital to the success of exploration and production projects. Also, the processing and interpretation of the data go a long way in informing technical decision making and establishing the economic viability of the exploration and production activities. For example, seismic exploration can provide information on the subsurface structures and give tentative indication of the presence of hydrocarbon. Additionally, information obtained from well-logs can lead to important insights on subsurface properties such as permeability, porosity, rock types, just to highlight a few.

From seismic data generated by the reflection method using wave energy, geological structures can be noted and the depth of seismic boundaries can be determined. For example, the reflection method detects small angular inconsistencies, pinches, faults, traps and sections where facies change. Well-log data can enhance predictability of formation characteristics. Well-log measurements are performed using acoustic signals with a much broader frequency spectrum, especially towards the higher frequencies.

Integrating both seismic and well-log data offers a good front to verify and calibrate reservoir properties. This process of integration is called well-tying. Well integration affords the conversion of well log measurements from depth to the time domain. Three dimensional seismic acquisitions permit accessing reservoir properties over a relatively large area. Seismic attributes are generated in the time domain.

One method by which well integration can be achieved is seismic inversion. However, this remains outside the scope of this work. This research work illustrates how seismic and well data can be combined using appropriate software to generate geological and petrophysical models from seismic and well log data respectively. Also, the research focuses on establishing a trend in the evaluation of selected petrophysical properties.

1.2 Statement of the Problem

Reservoir modelling is often associated with uncertainties that lead to inadequate description of the reservoir and inappropriate prediction of field performance. Although the integration of well and three dimensional seismic data is cardinal to the development of appropriate reservoir model, the success of integration depends on the quality of the data.

Static models can be generated to estimate water saturation, porosity, permeability, volume of shale, net-to-gross ratio, etc. These predictions should become more accurate as wells are added. Validation of reservoir properties can be achieved by comparing numerical models with simulation results. How the available data can be processed and imported for reservoir modelling and how generated models are populated for reliable approximation of reservoir properties are often challenges worth overcoming for better description and interpretation of a field's performance.

1.3 <u>Objectives</u>

This thesis was undertaken to achieve the following:

- Develop the appropriate geological model from structural and Stratigraphic information
- Develop the petrophysical models for reliable estimation of reservoir properties by combining well log and 3D seismic data to determine the variations of porosity, water saturation, net-to-gross and pore fluids in the chosen field from simulation results
- Achieve a workflow for the development of geological and petrophysical models
- Develop the appropriate petrophysical models for reliable estimation of petrophysical properties from simulation results and ppredict field performance

1.4 <u>Merit</u>

With the advent of technological advances, made possible by the development of different kinds of software to aid in prediction analysis, 3D seismic and well log data can be integrated to generate models that describe a field's performance thus affording predictions not far from actual field operations.

1.5 <u>Research Method</u>

This research was undertaken by using real field data sets obtained from the **AK Oil Field** in the Niger Delta Province of Nigeria. These data sets were quality checked (processed, imported and filtered) to ensure software for subsurface analysis and performance prediction. Data analysis and interpretation were conducted from simulated response pattern obtained by tying seismic and well log data from sets of constraints employed in using the **PETREL** application. By populating the geological model with well data, reservoir characterization was achieved for the determination of the AK field's performance.

1.6 Tasks Execution Schedule

For the implementation of the research, the dateline indicated below was adhered to:

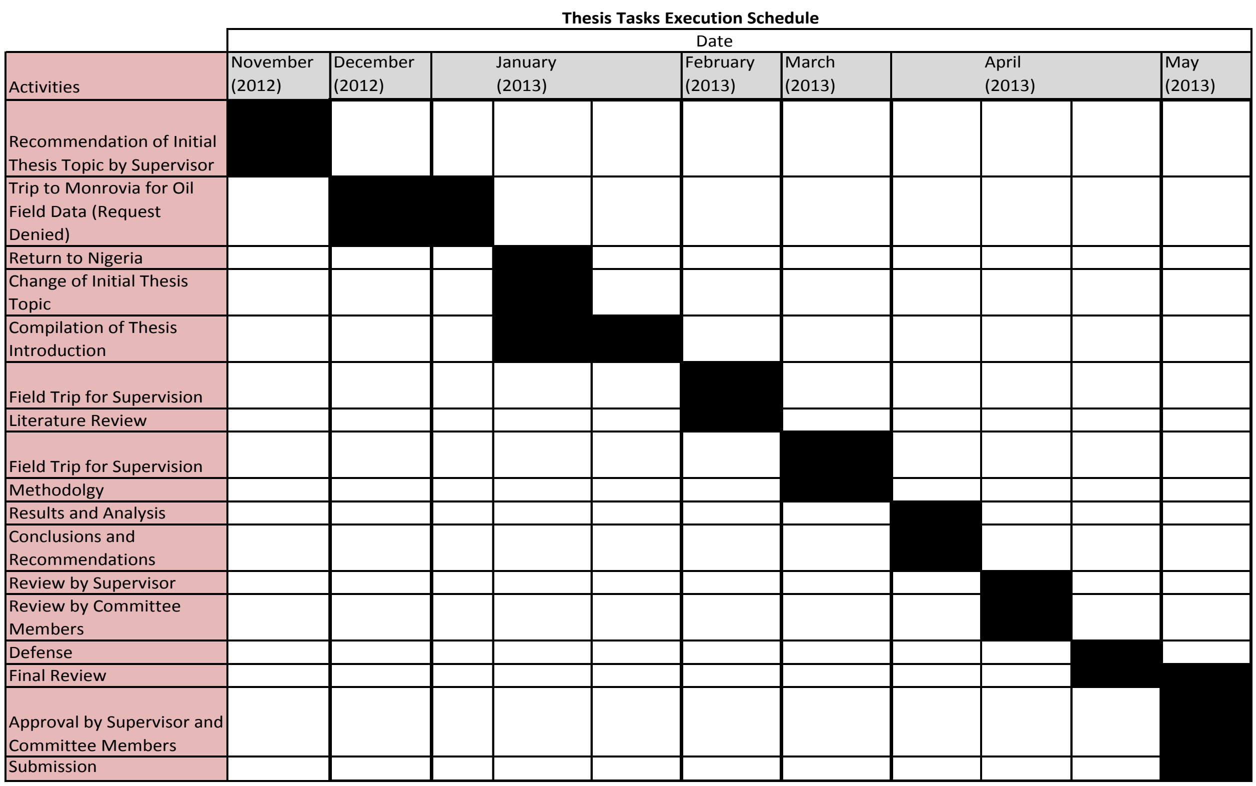


Figure 1.0: Task Execution Schedule for Thesis

1.7 Overview of the Niger Delta Province of Nigeria

The Niger Delta Province includes Nigeria, Cameroon and Equatorial Guinea. The province is situated in the Gulf of Guinea with one petroleum system, identified so far, and designated in Nigeria as the Tertiary Niger Delta (Akata-Agbada) petroleum system. Tuttle, Charpentier and Brownfield (1999) described the period of the formation of the Niger Delta. They outlined that the delta formed at the site of a rift triple junction related to the opening of the southern Atlantic starting in the Late Jurassic and continuing into the Cretaceous. They noted "The delta proper began developing in the Eocene, accumulating sediments that now are over 10 kilometers thick. The primary source rock is the upper Akata Formation, the marine-shale facies of the delta, with possibly contribution from interbedded marine shale of the lower most Agbada Formation".

The Niger Delta covers an aerial stretch of over **70,000 km²** within the Federal Republic of Nigeria and constitutes about **one-fourteenth** of the total land mass of the country. In Nigeria, originally, the Niger Delta constituted what were then Bayelsa, Delta and River States until its modification in the year 2000 to include a number of other states.

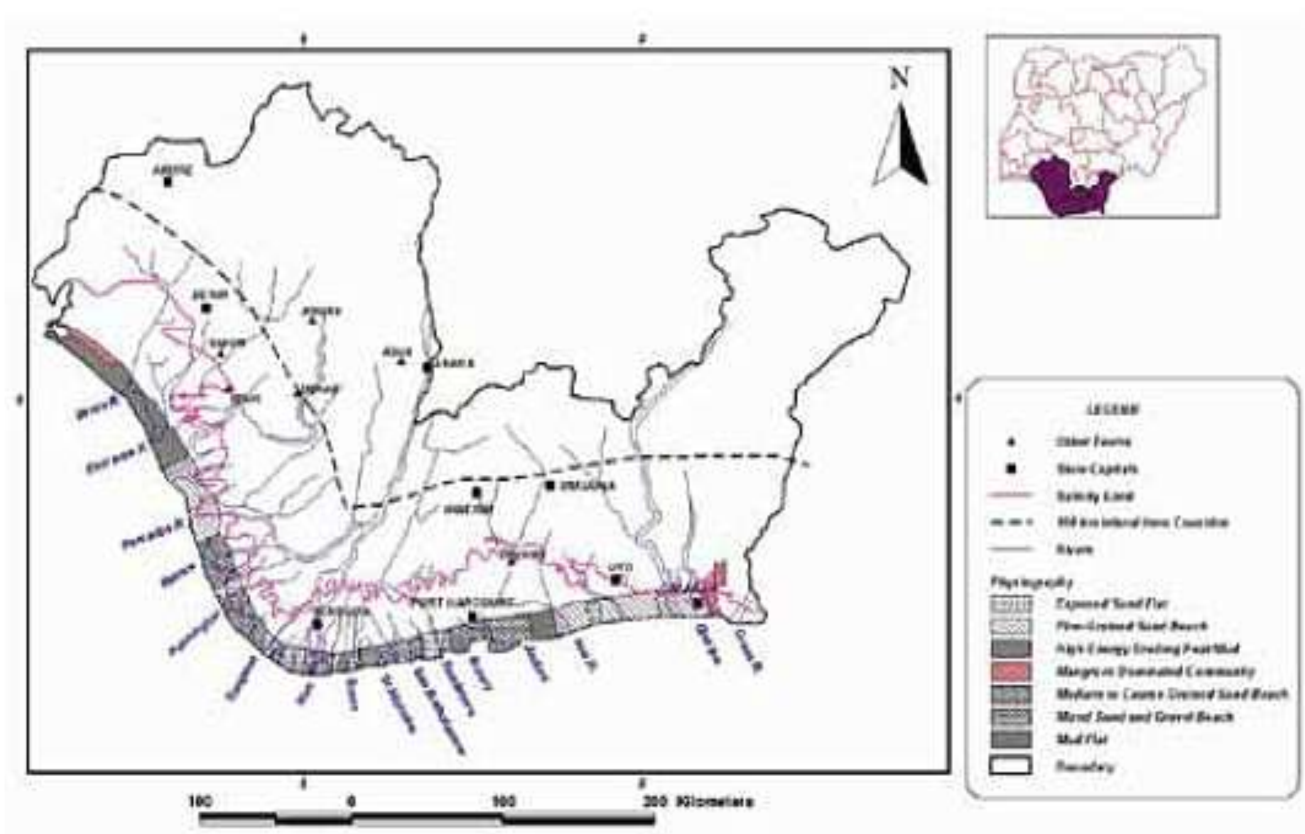


Figure 1.1: Diagram of the Niger Delta Province of Nigeria (Source: Internet)

The geologic history of the Niger Delta Province dates from Eocene period to recent times and remains the youngest of three depositional cycles leading to the development of the coastal sedimentary basin of Nigeria. The deposition of sediments within this period lasted from about 56 to 34 million years ago up till recent times bringing about three stratigraphic subdivisions, namely the Benin formation, the Agbada formation and the Akata formation.

Table 1: Formations of the Niger Delta Province of Nigeria

No	Formation	Lithology	Period of Occurence	Source	Depth	Location
1	Akata	-Thick shale sequence - turbidite sand - clay and silt	Paleocene through recent	Lowstands when terrestrial organic matter and clays were transported to deep water areas characterized by low energy conditions and oxygen deficiency (marine Origin)	7000 m	Base of the Delta
2	Agbada	Shale and sandstone	Eocene to recent		3700 m	Middle layer , major petroleum-bearing unit
3	Benin	sand	Eocene to recent	Alluvial and upper coastal plain	2000m	Upper layer of the delta.

Lithologically, the upper portion of the Niger Delta Province which makes up the Benin formation is sandy while the middle Agbada formation comprises an intervening unit of alternating sandstone and shale with the lower Akata formations predominantly shale. According to Short and Stauble (1967) “These three units extend across the whole delta and each ranges in age from early Tertiary to Recent. They are related to the present outcrops and environments of deposition”. They further pointed out that the Tertiary section of the Niger Delta

Province of Nigeria is divided into three litho-stratigraphic formations, representing prograding depositional facies that are distinguished mostly on the basis of sand-shale ratios.

Tuttle, Charpentier and Brownfield (1999) investigated the hydrocarbon potential of the Niger Delta. They noted that the "Petroleum in the Niger Delta is produced from sandstone and unconsolidated sands predominantly in the Agbada Formation. Characteristics of the reservoirs in the Agbada Formation are controlled by depositional environment and by depth of burial."

Magbagbeola (2005) studied the depositional sequence of the Niger Delta and found that Tertiary Niger Delta deposits are characterized by a series of depobelts that strike northwest-southeast, sub-parallel to the present day shoreline. He also observed that depobelts become successively younger basin ward, ranging in age from Eocene in the north to Pliocene offshore of the present shoreline.

As at 1999, the Niger Delta Province of Nigeria was estimated to hold recoverable oil and gas of around 35 billion barrels (bbl) and 94 trillion standard cubic feet (ft^3) gas respectively with production from sandstone facies within the Agbada Formation.

CHAPTER 2

LITERATURE REVIEW

2.1 Well Integration and Reservoir Properties

Well integration is the process of combining data from two or more distinct data sources so as to verify and calibrate reservoir properties and predict reservoir potential. In this research work seismic and well-log data are combined to ensure the success of well integration and good knowledge of the subsurface. It cannot be over-emphasized that petroleum resources are found hundreds of feet beneath the earth surface in heterogeneous formation and the precision of information on the location of these resources rely on the understanding of the geology of the formation.

Since the subsurface is physically inaccessible to the petroleum engineers and related professionals, the dependence on instrument is indispensable to any determination of petroleum resources in the subsurface. Keen understanding of the deflection pattern of instruments such as gamma ray logging tool, density log, spontaneous potential log, just to name a few, can assist in confirming response from seismometer on the formation properties. In this vein, the oil industries rely on data fed to it from equipment designed to acquire data in the formation and in comparison to those obtained from samples of formation rocks brought to the surface by the drilling equipment for petrophysical and other laboratory analyses.

Data obtained from the propagation of waves (either refraction or reflection method) can give clues on the formation characteristics. For example, seismic exploration techniques, based on the study of the propagation characteristics of elastic (seismic) waves in the earth's crust are used to investigate the crust's geological structure. Depending on the reflected or refracted wave signal, seismologists and geologists can predict the formation rock type at various depths from arrival time of the wave energy emitted into the formation. The wave's arrival time is a function of the structural or crystalline arrangement of rock atomic particles. Information obtained from the propagated wave is used in predicting rock hardness, rock stress, rock density etc and in classifying rock type.

Although the resolution obtained from seismic is relatively low when compared to well logging, the area of coverage of seismic acquisition is larger than that of well-logging. Well logging on the other hand gives high resolution but tends to be limited in that it only provides information at the well location- the wellbore. Well-log data however include but not limited to porosity, permeability, lithofacies, water saturation etc.

Tying seismic data to well data enables the prediction of geological ages, rock types, porosity, and fluid types away from the well and within the well of properties such as porosity variation, fluid types, top of abnormal pressure zones etc. from which petrophysical models can be derived.

2.2 Sources of Data Acquisition

The integration of data is at the core of reservoir modeling. The primary objective of integration is to explicitly account for and incorporate all data necessary for describing the reservoir and building models that approximate reality. In the petroleum industries, the principal areas from which data can be generated are:

- Seismic Survey
- Well Logs (Wire line or Logging-While-Drilling)
- Laboratory Analysis of Core
- Others

While the significance of other data sources cannot be under-rated, it is however important to state that for the purpose of this research task, emphasis would be placed on seismic survey and well log data.

Seismic Survey: This is the process of accessing and evaluating the surface and subsurface geology based on processed information obtained from propagated wave energy. Seismic survey is one of the key geophysical approaches used in exploring for petroleum resources and by far the leading and only geophysical approach used both in exploration and development phases. Magnetic and gravity surveys, the other two geophysical approaches or methods, are used only in pre-drilling exploration.

Seismic data can be acquired both onshore and offshore with virtually the same operational principles but with devices adapted to each terrain. On land, for instance, acoustic waves are generated at or near the earth surface by shooting seismic from sources such as dynamite, thumper (a weight dropped on ground surface), dinoneis (a gas gun), or a vibroseis (which literally vibrates the earth's surface). The acoustic waves which are transmitted into the earth from dynamite and the other named sources, when reflected are received by electronic devices called geophone. Here, the geophones digitize the waves after performing a number of signal processing stages such as amplification and filtering. The processed signals are then transmitted to a nearby truck to be recorded on magnetic tape or disk. The recorded data sets are displayed in a number of forms for interpretation and research purposes; including visual display forms (photographic and dry-paper), a display of the amplitude of arriving seismic waves versus their arrival time, and a common type of display called variable-density.

By utilizing information on travel time, arrival time, seismic survey provides a way of measuring the physical properties of the subsurface formation. These measurements give geological information which is significant in identifying structures such as faults and traps as well as provide information on depth, stratigraphy and position of source rocks.

For offshore seismic survey, that is obtaining subsurface data by propagating acoustic waves over marine environment, the seismic vessel replaces the on-land truck while receiver devices called hydrophones serve the same function as the geophones which receive reflected (incoming) signals during onshore seismic survey. Performing seismic survey offshore is cheaper comparably to onshore due to the involvement of smaller workforce. Also the offshore process is faster and simpler as most of the tasks are machine implemented.

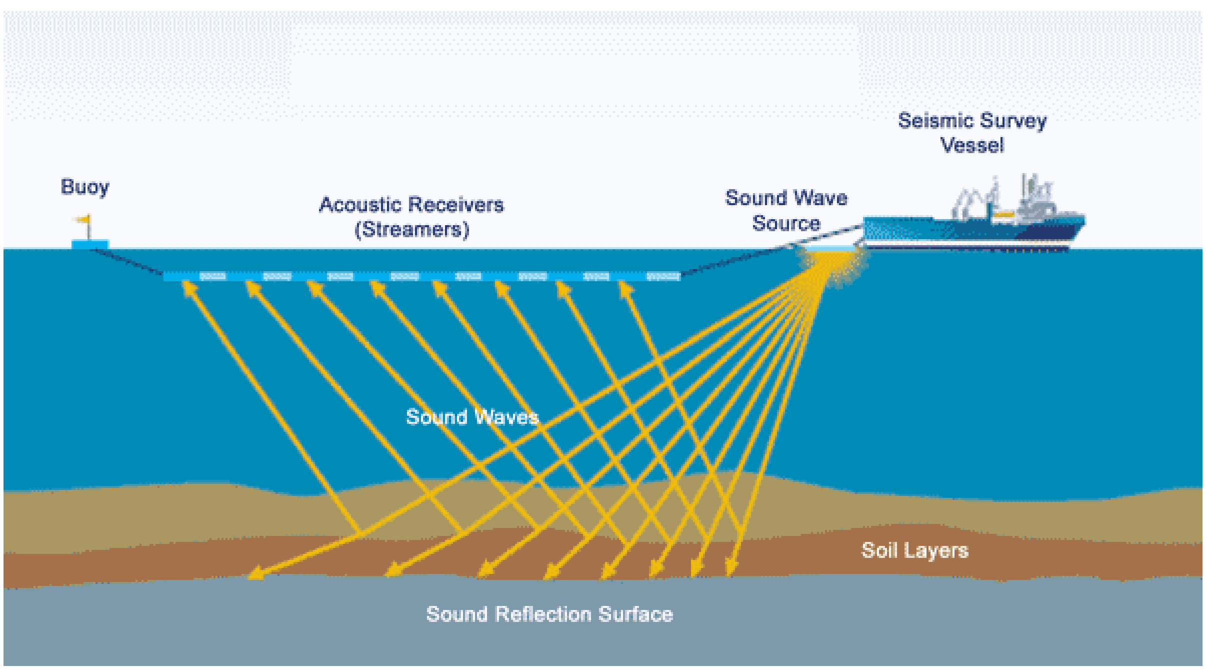


Figure 2.0: Seismic Survey Using Reflection Method (Source: Internet)

Well Logs: To conduct formation evaluation which is also linked to the analysis of the subsurface, wide range of measurements and geophysical techniques are required. Information gathered through the use of calibrated instruments enables the determination of the reservoir's extent, pay thickness, porosity, rock type, storage capacity, hydrocarbon content, and well produceability. Contingent on these parameters is also the determination of the economic value and production potential of the reservoir.

Well logging provides an excellent medium for the determination of the reservoir parameters. Well logging is the use of down-hole instrument, either during or after drilling, to evaluate the formation and measure reservoir parameters. Log measurements, when properly calibrated, can give the majority of the petrophysical parameters. Specifically, logs can provide a direct measurement or give a good indication of:

- Porosity, both primary and secondary
- Permeability
- Water saturation and hydrocarbon movability
- Hydrocarbon type (oil, gas, or condensate)
- Lithology
- Formation dip and structure
- Sedimentary environment

A single well log cannot exclusively extract all relevant data from a reservoir. Data obtained from well logs fitted for specific activities are assimilated and utilized for the evaluation of the reservoir. The table below indicates some of the most encountered well logging tools and data each may be capable of extracting from a well:

Table 2: Well Logging Tools and Associated Data

No	**Well Logging Tool**	**Data**
1	Sonic Log	Interval Transit Time
2	Density Log	Bulk Density
3	Porosity Log	Total Porosity
4	Gamma Ray Log	Shale Volume
5	Resistivity Log	Formation True Resistivity

Figure 2.1 Diagram of Density Logging Tool (Source: Internet)

Logging can answer many questions on topics ranging from basic geology to economics; however, logging by itself cannot answer all the formation evaluation problems. Coring, core analysis, and formation testing are all integral parts of any formation evaluation effort.

Laboratory Analysis of Core: A core is a cylindrical sample of the formation extracted from a depth of interest for laboratory analysis. Cores are cut where specific lithologic and rock parameter data are required. It is usually sampled and analyzed to determine static and dynamic reservoir properties. Static properties are reservoir properties with no relation to flow while reservoir properties in consideration to flow parameters are dynamic properties. Ranging from few inches to a couple of feet in length, two essential reservoir properties that can be extracted from core are permeability and porosity. Laboratory techniques used to analyze cores are:

- Bean Stark Method
- Archimedes Method
- Charles and Boyles' Law Methods

These techniques would not be discussed in here.

Others: Additional sources of information that can be used for modeling reservoir are as indicated below:

- Sequence stratigraphic interpretation/layering – gives information on definition of the continuity and trends within each layer of the reservoir
- Trends and stacking Pattern-available from a regional geological interpretation
- Analog data from outcrop or densely drilled similar field (size distributions, measure of lateral continuity)

- Well test and production data –gives information on the following interpreted data (permeability, thickness, skin, flow efficiency, channel widths, barriers, flow paths)

2.3 Overview of Petrophysical Properties

Tiab and Donaldson (2004) defined petrophysics as “the study of rock properties and their interactions with fluids (gases, liquid hydrocarbons, and aqueous solutions).”In petroleum studies, petrophysical properties are those properties of the reservoir which enable the reservoir rocks to store and transmit reservoir fluids thus also enabling quantitative determination of the in situ hydrocarbon as well as the appropriate method of extraction of the fluids”.

For the purpose of this research work, the key petrophysical properties of interest are:

- Water Saturation
- Porosity
- Permeability
- Volume of shale
- Net-to-Gross Ratio (Net-to-Gross Sand Distribution)

Other petrophysical properties include wettability, grain size and grain shape, degree of compaction, amount of matrix, cement composition, and type of fluid present.

Basic definition of key petrophysical properties

Water Saturation – this is the relative extent to which the pores in rocks are filled with water. Saturation is expressed as the fraction, or percent, of the total pore volume occupied by the oil, gas, or water. Water saturation is denoted **Sw** and is expresses in percent or fraction.

Porosity- is the fraction of the bulk volume of a material (rock) that is occupied by pores (voids). Denoted **ɸ,** porosity can also be defined as the ratio of the volume of void spaces in a rock to the total volume of the rock. Porosity is expressed in decimal or percentage and can represent the total volume of a rock occupied by empty space.

Permeability- In fluid flow, characterizes the ease with which fluids flow through a porous medium. Theoretically, permeability is the intrinsic property of a porous medium, independent of the fluids involved. Permeability is denoted **K** and expressed in unit of area (cm^2, m^2, ft^2 etc). In short, permeability is the measure of the ease with which a fluid flows through a rock.

Volume of Shale- This is the space occupied by shale or the fraction of shale (clay), present in reservoir rock. The Volume of Shale is determined from mathematical correlations and gamma ray index. In mathematical equations, the volume of shale is represented $\mathbf{V_{sh}}$.

Tiab and Donaldson (2004) identified the three common modes of shale distribution within a reservoir rock -sand, carbonates. They classified the shale types as laminar, dispersed and structural and noted their effect on reservoir properties. Description of the shale types are as outlined below:

- Laminar shale – This refers to thin beds of shale deposited between layers of clean sands. By definition, the sand and shale laminae do not exceed 0.5 in. thickness. The effect of this type of shale on porosity and permeability of the formation is generally assumed to be negligible.
- Dispersed clays – These are clays which evolved from the in situ alteration and precipitation of various clay minerals. They may adhere and coat sand grains or they may partially fill the pore spaces. This mode of clay distribution considerably reduces permeability and porosity of the formation, while increasing water saturation. This increase in water saturation is due to the fact that clays adsorb more water than quartz (sand).
- Structural shale exists as grain of clay forming part of the solid matrix along with sand grains. This type of clay distribution is a rare occurrence. They are considered to have properties similar to those of laminar shale, as they are both of depositional origin. They have been subjected to the same overburden pressure as the adjacent thick shale bodies and. thus are considered to have the same water content.

Net-to-Gross Ratio - The net-to-gross ratio reduces the maximum reservoir thickness to the anticipated pay (permeable reservoir) thickness. Net-to-Gross Sand is reservoir thickness less shale thickness. This is a factor used to identify probable producing regions of a formation.

2.4 Petrophysical Correlations

Formation evaluation tools provide log analysis using petrophysical interpretation models that have either a deterministic approach or stochastic approach. Petrophysical models, like other models, can be analysed using series of sequential equations that relate formation attributes to log measurements.

For reservoir modelling, the fundamental petrophysical correlations can be employed to model:

- Water Saturation
- Porosity
- Permeability
- Shale Volume
- Net-to-Gross Ratio

2.4.1 Water Saturation Correlation

Archie's Equation

The most widely used computation method in determining saturation relies on the work originally done by Gus Archie .From empirical analysis, in shale free, water filled rock, Archie obtained the relationship indicated in Table 3.

The relationships derived from Archie's empirical analysis, are valid for computing water saturation under the following conditions:

- Reservoir rock is non-shaly
- Rock pores are saturated with water and/or hydrocarbons
- Formation is composed of clean sand

The variables required to use Archie's Equation can be found using open hole logging tools such as Density and Neutron Porosity and Resistivity logs.

Table 3: Mathematical Relationships Describing Archie's Equation

S/N	Relationship	Parameter Definition
1	$\mathbf{F} = \frac{R_o}{\mathbf{R_w}}$	F = formation factor**(dimensionless)** R_o = resistivity of rock in ohms-meter (Ω-m) R_w = resistivity of water in ohms-meter (Ω-m)
2	$\mathbf{F}=\frac{\boldsymbol{a}}{\boldsymbol{\phi^m}}$	F= formation factor**(dimensionless)** a = empirical constant approximately equal to 1 m = cementation constant approximated 2 ϕ = porosity in fraction or decimal
3	$\frac{R_t}{R_o} = \frac{1}{Sw^n}$	R_t = true resistivity in ohms-meter (Ω-m) R_o = resistivity of rock in ohms-meter (Ω-m) S_w = water saturation in percent n = saturation exponent approximated 2
4	$S_w = \sqrt{\frac{aR_w}{R_t\phi^m}}$	S_w = water saturation in percent a = empirical constant approximately equal to 1**(a factor that depends on the rock type)** R_w = resistivity of water in ohms-meter (Ω-m) ϕ = porosity in fraction or decimal m = cementation or porosity exponent constant approximated 2 R_t = true resistivity in ohms-meter (Ω-m)
5	$C_t = \phi^m Sw^n (C_w)$	C_t = formation true conductivity in mho/m ϕ = total porosity in fraction or decimal m = cementation or porosity exponent constant S_w = water saturation in percent n = saturation exponent C_w= water conductivity in mho/m

Tixier and Humble incorporated adjustment factor into the Archie's formation factor equation that hold for sandstone formation. Similar approach has been noted for carbonate formation.

Below are modified equations taking into account lithology:

$\boldsymbol{F = \frac{0.8a}{\phi^2}}$---------------------------- Equation1a: Tixier Equation for Sandstone formation

$\boldsymbol{F = \frac{0.62a}{\phi^{2.15}}}$----------------------------Equation 1b: Humble Equation for sandstone formation

Waxman-Smits' Equation

As stated above, the Archie's equation is applicable and accurate in calculating water saturation in non-shaly and clean sand formation. This implies that the Archie's equation holds in most cases for ideal or near perfect condition where there is no invasion of fines into a formation.

To accurately capture the effect of shaly sand in the evaluation of water saturation in formation, the Waxman-Smits' equation can be applied. With reliance on experimental techniques, as in the case of Archie's equation, electrical properties and cation exchange capacity are determined in the Waxman-Smits' method.

Below is the Waxman- Smits' equation for determining water saturation for shaly rock:

$C_t = \phi^{m*} Sw^{*n} \left(C_w + \frac{BQ_v}{S_w} \right)$ ---------------------Equation 2: Waxman-Smits' Equation

Where:

C_t = Formation True Conductivity (1/Rt), mho/m

ɸ = total porosity in fraction or decimal

m* = Waxman Smits' cementation or porosity exponent constant

S_w= true water saturation of the formation

C_w= water conductivity in mho/m

n* = Waxman Smits' saturation exponent

B = Exchangeable cations conductivity, (mho/m)/(meq/cc)

Q_v = Cation-Exchange-Capacity of clay, meq/cc

Simandoux (Total Shale) Equation

The generalized equation for the description of a water saturation model for shaly sandstone formation is the Simandoux equation. Its general acceptance is derived from the incorporation of the effect of the three general forms of clay distribution-laminar, dispersed and structural clays-that have been found to exist in sandstone formation. Shale types and effects have already been discussed in **Section 2.3** of the work.

The Simandoux equation can be expressed in the quadratic form $\mathbf{AS^2_w + BS_w + C = 0.}$ The constants A,B and C are mathematically expressed and defined as indicated in the table below.

Table 4: Mathematical Definition of Constants in the Generic form of the Simandoux Equation

S/N	Symbol	Mathematical Expression of Symbol	Definition of Symbol
1	A	$A = \frac{\phi^m}{aR_w(1 - V_{sh})}$	Denotes the combined effect of the amount of sand, its porosity, cementation, and the resistivity of the saturating water. A always reduces to the Archie saturation equation when the shale volume, Vsh, is zero.
2	B	$B = \frac{V_{sh}}{R_{sh}}$	Denotes the combined effect of the amount of shale and its resistivity
3	C	$C = \frac{1}{R_t}$	Denotes the reciprocal of the total resistivity of the shaly sand system

The Simandoux equation is a better alternative to model water saturation in the Niger Delta region given its consideration for the effect of shale types. Expansion of the Simandoux equation gives:

$\left\lfloor\frac{\phi^m}{aR_w(1-V_{sh})}\right\rfloor Sw^2 + \left\lfloor\frac{V_{sh}}{R_{sh}}\right\rfloor S_w - \frac{1}{R_t}$ **= 0 ----------------------**Equation 3a: Generalized Simandoux Equation

$\left\lfloor\frac{\phi^m}{aR_w}\right\rfloor Sw^2 + \left\lfloor\frac{V_{sh}}{R_{sh}}\right\rfloor S_w - \frac{1}{R_t}$ **= 0------------------------** Equation 3b: Modified Simandoux Equation

Solving the quadratic equation, immediately above, for Sw gives:

Sw = $\left(\frac{aR_w}{2\phi^m}\right)\left[-\left(\frac{V_{sh}}{R_{sh}}\right)+\left(\left(\frac{V_{sh}}{R_{sh}}\right)^2\right)+\left(\left(\frac{4\phi^m}{aR_wR_t}\right)^{.5}\right)\right]$--------------- Equation 3c: Simandoux Equation for Determining Water Saturation

2.4.2 <u>Porosity Correlation</u>

Porosity can be determined from laboratory analysis of core or from down-hole instruments. The numerical model used for porosity estimation is given by:

$\phi = \frac{(\rho_g - \rho_b)}{(\rho_g - \rho_f)}$-- Equation*4:* Density Porosity Equation

Where

ϕ = Porosity obtained from density log input

ρ_g = rock grain (matrix) density

ρ_b = bulk density (from the log)

ρ_f = fluid density (often assumed to be mud filtrate density)

2.4.3 <u>Permeability Correlation</u>

Rose-Wyllie Equation

This research focuses on the Niger Delta, whose geology has already been discussed. Two basic assumptions must be reiterated to establish the basis of developing models on the AK field. The first assumption is that the formation, although sandstone has shale volume comprising of the three general forms of shale. The second assumption worth emphasising is that the shale volume constitutes not more than 10% of the formation pore spaces.

Contingent upon the above, the appropriate flow (Permeability) model to describe this low shale formation of the Niger Delta is that of Rose-Wyllie equation cited below:

$log(RQI_{sh}) = \left[\frac{(C_2 + m-1)}{2}\right] log\phi + log\left[0.314\left(\frac{C_1 R_t}{a(1-V_{sh})R_w}\right)^{0.5}\right]$ --------Equation 5a: Generalized Rose-Wyllie Equation

Where RQI_{sh}(Reservoir Quality Index) = $\left[0.314\left(\frac{K}{\phi(1-V_{sh})R_w}\right)^{0.5}\right]$

FZI_{sh} (Flow Zone Indicator) = $\left[78.5\left(\frac{R_t}{a(1-V_{sh})R_w}\right)^{0.5}\right]$

$C_1$and C_2 (correlation constant) = 62,500 and 6 respectively

Substituting the values of C_1 and C_2 reduces Eqn. 8a to:

$\boldsymbol{log(RQI_{sh}) = [0.5m + 2.5]log\phi + log\left[78.5\left(\frac{R_t}{aR_w}\right)^{0.5}\right]}$------------- *Equation 5b: Simplified Rose-Wyllie Equation*

Tiab & Donaldson (2004) investigated the influence of shale distribution on permeability in heterogeneous formations. They noted that the overall reservoir quality in heterogeneous sandstones is controlled by diagenesis, dissolution of feldspars amongst others.

2.4.4 Shale Volume Correlation

Shale is a fine-grained, clastic sedimentary rock composed of mud that is a mix of flakes of clay minerals and tiny fragments (silt-sized particles) of other minerals, especially quartz and calcite. The ratio of clay to other minerals is variable. Shale is characterized by breaks along thin laminae or parallel layering or bedding less than one centimeter in thickness, called fissility.

The shale volume model can be generated from the equation below:

$$V_{sh} = \frac{GR - GR_{cs}}{GR_{sh} - GR_{cs}}$$

Where:

GR = gamma ray reading obtained from gamma ray log

GRcs = clean sand gamma ray reading (minimum gamma ray value)

GRsh = Clean shale gamma ray reading (maximum gamma ray value)

2.4.5 Net-to-Gross Ratio Correlation

Net-to-Gross is reservoir thickness less that of shale. In this case, the numerical model for net – to-gross is related to shale volume in the following way:

Net-to-Gross = 1- V_{sh} --Equation 6b: Net-to-Gross Equation

2.5 Acquisition of Petrophysical Data from Well Logs

Devices designed to record or measure subsurface properties in the wellbore are generally referred to as well logs. Although there are many different well logs, few will be discussed below.

2.5.1 Resistivity Log

Resistivity logs measure the ability of rocks to conduct electrical current and are scaled in units of ohm-meters. There is a wide variety of resistivity tool designs, but a major difference between them lies in their "depth of investigation" (how far does the measurement extend beyond the borehole wall?) and their "vertical resolution" (what is the thinnest bed that can be seen?). These characteristics become important because of the process of formation "invasion" that occurs at the time of drilling.

2.5.2 Density Logs

The density logs record a formation's bulk density. This is essentially the overall density of a rock including solid matrix and the fluid enclosed in the pores. The log is scaled linearly in bulk density (g/cm^3) and includes a correction curve that indicates the degree of compensation applied to the bulk density data. Density logging is based on the physical phenomenon of gamma ray scattering as a function of the bulk density of an environment irradiated by a gamma ray source. Density logs are primarily used as porosity logs. The density log can be used to obtain qualitative and quantitative information as outlined Table 5.below.

Table 5: Types of Information obtainable from Density Log

Qualitative information	Quantitative Information
-lithology indicator -identification of some minerals - assessment of source rock organic matter content -identification of overpressure and fracture porosity	-input (bulk density, fluid density, grain density) can be used to calculate porosity - calculate the density of the hydrocarbon - calculate acoustic impedance

From density log reading, the following equation can be used to generate porosity of the formation:

$\boldsymbol{\Phi} = \frac{(\rho_g - \rho_b)}{(\rho_g - \rho_f)}$ -- Reference Equation 4

Where

ϕ = Porosity obtained from density log input

ρ_g = rock grain (matrix) density

ρ_b = bulk density (from the log)

ρ_f = fluid density (often assumed to be mud filtrate density)

2.5.3 Sonic Log

The sonic log is a device that measures the time it takes sound pulses to travel through the formation. This time is referred to as the interval transit time, or slowness and it is the reciprocal of velocity of the sound wave. The interval transit time of a given formation is dependent on the lithology and porosity. Therefore a formation's matrix velocity must be known to derive sonic porosity either by chart or by using formula.

Wyllie's equation can be used to calculating the matrix porosity of consolidated sandstone and carbonate formations respectively. The applicability of the formula holds for sandstone with inter-granular porosity or carbonate with inter-crystalline porosity. The formula incorporates an adjustment factor, designated empirical compaction factor (**Cp**), to account for unconsolidated formation as indicated in the table below:

Table 6: Wyllie's Mathematical Formula for Determining Sonic (matrix) Porosity

Formula Name	**Formula**	**Type of Formation**
Wyllie et al	$\phi_{sonic} = \frac{(\Delta t_{log} - \Delta t_{ma})}{(\Delta t_f - \Delta t_{ma})}$	Consolidated sandstone and carbonate formation
	$\phi_{sonic} = \frac{(\Delta t_{log} - \Delta t_{ma})}{(\Delta t_f - \Delta t_{ma})} x \left(\frac{1}{C_p}\right)$	Unconsolidated sandstone and carbonate formation

Where:

ϕ_{sonic} = sonic derived porosity

Δt_{ma} = interval transit time of the matrix in microsecond per foot (μs/ft), derived from table

Δt_{log} = interval transit time of the formation in microsecond per foot (μs/ft)

Δt_f = interval transit time of the matrix in microsecond per foot (μs/ft)

(fresh mud = 189(μs/ft) while salt mud = 185(μs/ft))

Cp = empirical conversion factor

The empirical conversion factor is derived from the relationship:

$Cp = (\Delta t_{sh} \times C)/(100)$ --- Equation 7a:Wyllie's Equation

Where

Δt_{sh} = interval travel time of adjacent shale (μs/ft)

C = a constant which is normally 1.0 (Hilchie constant)

It is worth noting that the interval travel time of the formation is increased due to the presence of hydrocarbon. To correct for the effect of hydrocarbon, Hilchie constant can be introduced.

$\Phi = 0.7 \times \phi_{sonic}$ for gas bearing formation ---------------------Equation 7b: Wyllie's Equation

$\Phi = 0.9 \times \phi_{sonic}$ for oil bearing formation -------------------Equation 7c: Wyllie's Equation

Wyllie's equation will yield a low porosity value when the sonic porosities of carbonate with vuggy or fracture porosity are calculated from it. This is due to the fact that the sonic log only records matrix porosity rather than vuggy or fracture secondary porosity. To determine the total porosity of a vuggy or fracture carbonate formation, a density or neutron log is required. The log reading obtained from the sonic log is subtracted from either density or neutron log reading to obtain the secondary (vuggy) porosity.

Integrated sonic logs can also be useful in interpreting seismic records, and can be very invaluable in the time to depth conversion of seismic data. The sonic log can be interpreted for information on the following:

- Formation Evaluation- porosity, lithology identification, gas detection, fracture, permeability, detection of abnormal Formation Pressure etc
- Mechanical Property Analysis - Sanding analysis, Fracture height, Wellbore stability

- Geophysical Interpretation - Synthetic seismograms, VSP, AVO Analysis

2.5.4 Neutron Logs

Neutron logs are used principally for delineating porous formations and determination of porosity. Neutron logs measure the hydrogen ion concentration in a formation. Therefore in clean formations, whose pores are filled with water or oil, neutron logs respond to the amount of liquid-filled porosity**.**

In neutron logging there are three processes of interest: neutron emission, neutron scattering and neutron absorption. Neutrons are created from a chemical source in the neutron logging tool, which continually emits neutrons. These neutrons collide with the nuclei of the formation material, and result in a neutron losing some of its energy. Because the hydrogen atom is almost equal in mass to the neutron, maximum energy loss occurs when the neutron collides with a hydrogen atom. Also because hydrogen in a porous formation is concentrated in the fluid-filled pores, energy loss can be related to the formation's porosity.

Neutron logs responses vary, depending on:

- Differences in detector types,
- Spacing between source and detector, and
- Lithology – i.e. sandstone, limestone, and dolomite.

These variations can be compensated for by using the appropriate charts. It is important to note that unlike all other logs, neutron logs must be interpreted from the specific chart designed for a specific log. This is so because, unlike other logs that calibrated in basic physical units, neutron logs are not.

2.5.5 Gamma Ray Log

The Gamma Ray logging is a continuous measurement of the natural radioactivity emanating from the formations. Principal isotopes emitting radiation are Potassium-40, Uranium, and Thorium (K40, U, Th). Isotopes concentrated in clays; thus emit higher radioactivity in shales than other formations. Sensitive detectors count the number of gamma rays per unit of time. Gamma Ray logs are recorded in “API Units” which is 1/200th of the calibrated, standard response.

From the gamma ray log the following information about the formation can be generated:

- Estimate bed boundaries,
- Stratigraphic correlations
- Estimate shale content
- Perforating depth control
- Identify mineral deposits of potash, uranium, and coal
- Monitor movement of injected radioactive material

2.5.6 Spontaneous Potential Log

The spontaneous potential log is a well-logging device that measures the difference in the natural electrical potentials that occur in boreholes and generally distinguishes porous, permeable sandstones from intervening shales. The natural driving force or "natural battery" is caused when the use of drilling mud with a different salinity from the formation waters, causes two solutions to be in contact that have different ion concentrations. Ions diffuse from the more concentrated solution (typically formation water) to the more dilute.

The SP log has the following main uses:

- The detection of permeable beds.
- The detection of boundaries of permeable beds
- The determination of Rw.
- The determination of the volume of shale in permeable beds.
- The detection of hydrocarbons from SP response Correlation.

2.6 Basics of Reservoir Rock Classification

A petroleum system refers to geologic components and processes necessary to generate and store hydrocarbons. Appropriate relative timing of formation of these elements and the processes of generation, migration and accumulation are necessary for hydrocarbons to accumulate and be preserved. What is referred to as a petroleum system is amalgamation of five basic components. These include:

- Source rocks – these are rocks within which oil and/or gas is generated from organic matters
- Migration pathway - the movement of oil from the area in which it was formed to a reservoir rock where it can accumulate
- Reservoir rock - a permeable rock that may contain oil or gas in appreciable quantity and through which petroleum may migrate
- Trap - a body of permeable oil-bearing rock surrounded or overlain by an impermeable barrier that prevents oil from escaping. The types of traps are structural, stratigraphic, or a combination of these

- Seal - impermeable rock overlying an oil or gas reservoir that tends to prevent migration of oil or gas out of the reservoir.

Reservoir rocks are dominantly sedimentary and are of two types. Namely:

- sandstones and
- carbonates

However, highly fractured igneous and metamorphic rocks have been known to produce hydrocarbons, although on a much smaller scale.

2.7 Application of 3D Seismic Data to Reservoir Characterization

The advent of three dimensional seismic survey brought with it improvement in petroleum exploration. Unlike two dimensional seismic acquisition which gives apparent dip, three dimensional seismic made possible the determination of true structural dip which significantly aided in stratigraphic description.

Also, geologists and geophysicists were able to construct map view of reservoir properties which led to information on gross porosity, gross sand/shale, pay thickness etc. based on information obtained from 3D seismic. In addition, reservoirs could be delineated with better areal mapping of fault patterns and connection. Lateral resolution of the formation was improved by the use of three dimensional seismic surveys.

Research has shown that seismic data can be used to estimate lithologic components, porosity, and thickness variations laterally and vertically. Several reservoir models such as porosity model, saturation model, permeability model etc can be developed from seismic survey data.

Dynamic 3D static models have been developed in consideration of fluid flow properties in the reservoir. Data obtained from well testing and production profile have been used in the construction of these dynamic models. Pressure profiles, flow rates, flow efficiency, permeability are a number of dynamic reservoir properties which play important role in the construction of the dynamic models.

2.8 Application of Well logs Data to Reservoir Characterization

As stated above, well logging is the use of down-hole instrument(s), either during or after drilling, to evaluate the formation and measure reservoir parameters. Well log is a continuous record of measurement made in borehole respond to variation in some physical properties of rocks.

Well logging technology finds application in all the phases of the exploration and production process. The technology is used during the drilling of the first wild cat well in a field up to the abandonment of the last productive level in the same field. Well logs can measure a large number of physical properties of the geological formation (and the surrounding environment) intersected by a well both in open and cased hole conditions. Unlike mud log or core data which are either qualitative or quantitative, well log data are both quantitative and continuous.

From well logs the following information on the formation can be obtained:

- depth to lithological boundaries
- lithology identification
- minerals grade/quality
- inter-borehole correlation
- structural mapping
- dip determination
- rock strength
- in-situ stress orientation
- fracture frequency
- porosity
- fluid salinity

2.8.1 Advantages and Limitations of Well Log and Seismic Data

Although the resolution obtained from seismic survey is relatively low when compared to well logging, the reach of seismic is much larger than that of well-logging. This goes to say that the area of coverage of seismic survey is larger than well-logging. Well logging on the other hand gives high resolution but tends to be limited in that it only provides information at the well location (immediate well surrounding).

Provided below are the strengths and shortcomings of well and seismic data respectively:

Well log data

Strengths

- Provides remotely sensed values of reservoir properties and fluids
- Among the most abundant reservoir data
- Presentation results fairly well standardized
- Allows evaluation of lateral (map) and vertical (cross-section) changes in reservoir properties and fluids
- provides vertical resolution of well

Limitations

- Indirect measurements
- Vertical resolution
- Depth of investigation

Seismic Data

Strengths

- spatial continuity
- can give information of the formation up to an area of 7500 km^2
- provides excellent lateral coverage of the reservoir
- Can detect both lateral and depth variations in a physically relevant parameter: seismic velocity
- Can produce detailed images of structural features present in the subsurface.
- Can be used to delineate stratigraphic and, in some instances, depositional features.

- Direct detection of hydrocarbons, in some instances, is possible

Limitations

- Lacks vertical resolution
- Band-limited, reducing resolution and quality.
- Amount of data collected in a survey can rapidly become overwhelming.
- Data is expensive to acquire and the logistics of data acquisition are more intense than other geophysical methods.
- Data reduction and processing can be time consuming, require sophisticated computer hardware, and demand considerable expertise.

2.9 Integration of Well and 3D Seismic Data

Hirofumi Yamamoto (2003) performed data integration employing well logs, 3D seismic and core data. He noted that seismic survey data help define horizons of geological formations since its areal resolution is superior compared to well log data. Seismic data is also used in reservoir modeling with geo-statistics, which uses the survey data as one of the constraints to build static models.

In exploration and production, data integration is not a mere statistical gymnastics. Tying data is significant for validation of reservoir potential. The integration of data is employed for both technical and economic decision making. Information obtained from seismic survey indicating rock type and bright spots are used in preliminary decision making for the drilling of wild cat.

In this regard, well logging provides a complementary front for the validation and acquisition of data not accessible through seismic survey. Kevin Jarvis outlines the risks and rewards of data integration. He cautioned that "Each of these data [obtained from seismic or well logging] represents imperfect measurements with a certain level of error. The manner in which these errors are handled affects the integration of the two data types and determines the quality of the final reservoir model." This implies that integration is not the ultimate solution to determining a suitable or appropriate reservoir model, good insight of the techniques of integration is vital in reservoir characterization.

Kevin Jarvis also noted "No seismic dataset is perfect. Every attempt is made during acquisition and processing to choose optimum parameters. Relative amplitudes must be preserved during processing both vertically and spatially and stacking velocities must be optimized to properly image the geology."

2.10 Overview of the PETREL Software

PETREL is a software tool used in evaluating and modeling petroleum reservoir. Initially developed in Norway by a company called Technoguide, PETREL became commercially available in 1998.Today PETREL is developed and marketed by the world's biggest petroleum service company, **Schlumberger** since the acquisition of the Norway-based Technoguide in 2002**. PETREL** is designed as a "Windows" personal computer program application which handles data from field operations imported into format compatible with the software. There are many versions of **PETREL**; all produced by **Schlumberger**. Higher versions of **PETREL** are back compatible; making it equipped with program application which enables it (higher version) to handle applications suited for lower versions. This research work uses Petrel **Version 2009.1**.

As downloaded from the website Wikipedia, "PETREL version 2009.1 released in February 2009 was the first version of Petrel to be fully 64bit and to run on Microsoft's Window Vista 64 bit Operating System. This brings large performance benefits to users especially those working in exploration or with large seismic volumes and geological models. **PETREL 2009.1** also handles other enhancement such **as** Seismic Inversion"**.**

PETREL Manual (2012) outlines "Among the many applications offers by PETREL are three dimensional (3D) visualization, 3D mapping and 3D reservoir modeling". Besides the generation of geophysical and property models, PETREL finds application in production related activities by its ability to simulate a flow model. Model visualization can also be achieved in two dimensional (2D) displays.

The ease and efficiency with which PETREL can be used by many geoscientists and petroleum scientists is derived from its associated Microsoft Windows user interface standards on buttons, dialogs and help systems.

2.10.1 The PETREL Data Types and Formats

Data used (imported) in PETREL application can be categorized under one of the main data kinds:

- Well Data
- Well Tops Data
- Seismic Data
- Fault Data
- Isochores Data

The table below illustrates the principal PETREL data kinds and their associated categories.

Table 7: Petrel Data Types with their File Formats, Categories, Domains and Data Editor

No.	DATA	DATA CATEGORY	DATA FORMAT (FILE TYPE)	DATA TYPE	Domain	PETREL Data Editor
1	**Well**	Well headers	Well heads (*.*)	Well	Depth	NotePad, PSPad, WordPad
		Well Paths/Deviations	Well Path /deviation (ASCII) (*.*)	Well	Depth	
		Well Logs	Well Log (ASCII) (*.*)	Well	Depth	
		Checkshots	Checkshots (ASCII) (*.*)	Well	Depth	
2	**Well Tops**		Well Tops (ASCII) (*.*)	Well Tops	Depth	NotePad, PSPad, WordPad
3	**3D Seismic**	Horizon	Seismic data in ZGY bricked format(*.zgy)	Lines	Time	NotePad, PSPad, WordPad
4	**Fault**	Fault Polygons	Zmap+ lines (ASCII) (*.*)	Lines	Time	NotePad, PSPad, WordPad
		Fault Sticks	Zmap+ lines (ASCII) (*.*)	Lines	Time	
5	**Isochore**	Thickness	Zmap+ grid (ASCII) (*.*)	Surface	Depth	NotePad, PSPad, WordPad
6	**Properties**	Property	Zmap+ grid (ASCII) (*.*)	Surface	Respective Template	NotePad, PSPad, WordPad
7	**Velocity**	Property	Zmap+ grid (ASCII) (*.*)	Surface	Velocity Template	NotePad, PSPad, WordPad

Data type imported into PETREL for modeling is contingent on the intended purpose of the work to be done by the software. For reservoir modeling and petrophysical evaluation of reservoir, all of the data indicated in the table will be required. It is recommended that data be imported in the order in which they are listed in Table 7.

2.10.2 <u>Uses of the PETREL Software</u>

As summarized by Wikipedia "PETREL allows the user to interpret seismic data, perform well correlation, build reservoir models suitable for simulation, submit and visualize simulation results, calculate volumes, produce maps and design development strategies to maximize reservoir exploitation. It addresses the need for a single application able to support the "seismic-to-simulation" workflow, reducing the need for a multitude of highly specialized tools. By bringing the whole workflow into a single application risk and uncertainty can be assessed throughout the life of the reservoir".

2.10.3 Limitations of the PETREL Software

The success of reservoir modeling and petrophysical evaluation is dependent on the data acquired, processed and imported. For better reservoir characterization more quality checked data are required. Limited data may lead to poorer results.

CHAPTER 3

METHODOLOGY

3.1 Data Scope

As indicated above, the data used for the research was obtained from a field, in the Niger Delta Province of Nigeria, designated **AK Field**, which is producing oil. These data were made available to develop a reservoir model, highlighting the stratigraphy and static reservoir properties from which petrophysical models could be developed. Although multiple wells were logged, the research employs data from only thirteen (13) wells that were available. The data acquired from the **AK field** for research are indicated in Table 8.

Table 8: Data Categories from the AK Oil Field of the Niger Delta Province

No.	DATA	DATA CATEGORY	TOTAL NUMBER OF WELLS	WELL NAME (DESIGNATION)
1	**Well**	Well headers	13	AK
		Well Paths/Deviations		
		Well Logs		
		Checkshots		
2	**Well Tops**			
3	**3D Seismic**	Horizon		
4	**Fault**	Fault Polygons		
		Fault Sticks		
5	**Isochore**	Thickness		

Information obtained from data categories of the AK field, amongst others, include:

- Well name
- Well Coordinates (position of well on the earth, X and Y direction)
- Depth Drilled
- Kelly Bushing
- Marker Name

- Horizon (top depth, bottom depth)
- Angle of inclination
- Dip Angle
- Dip Azimuth

3.2 <u>Data Import (Loading) Into PETREL</u>

The PETREL software contains INPUT Section, called PETREL Explorer; into which data can be imported. Except for well data, all the other principal data categories are imported obeying similar procedure. It is important to mention that data to be imported must be compatible with the PETREL Format. Refer to column 4 of **Table 7 for PETREL** compatible data format.

3.2.1 <u>Order of Importing Data into PETREL</u>

Data are imported into PETREL in the order listed below.

Table 9: Order and Steps in Which Data are Imported into PETREL INPUT Explorer

Order	DATA	DATA CATEGORY	STEP	COMMENT
1	**Well**	Well headers	First	Import of well data is followed by the import of Well Tops data to be followed by 3D Seismic data. The last two data sets to be imported followed the order faults first and then isochores.
		Well Paths/Deviations	Second	
		Well Logs	Third	
		Checkshots	fourth	
2	**Well Tops**			
3	**3D Seismic**	Horizon		
4	**Fault**	Fault Polygons	First	
		Fault Sticks	Second	
5	**Isochore**	Thickness		

3.2.2 <u>Creating Data in PETREL DATA Editor</u>

Data for PETREL application can be edited using a number of editing tools which include **Notepad, WordPad, Word and PSpad.** The data formats used for data importation to the **PETREL Explorer** for the generation of geological and petrophysical models for the **AK field** are given in Table **10**. For the model development exercise, the PSpad Data Editor was used.

Table 10: Data File Types for Import to PETREL Explorer

No.	DATA	DATA CATEGORY	DATA FORMAT (FILE TYPE)	PETREL Data Editor
1	**Well**	Well headers	Well heads (*.*)	PSpad
		Well Paths/Deviations	Well Path /deviation (ASCII) (*.*)	
		Well Logs	Well Log (ASCII) (*.*)	
		Checkshots	Checkshots (ASCII) (*.*)	
2	**Well Tops**		Well Tops (ASCII) (*.*)	PSpad
3	**3D Seismic**	Horizon	Seismic data in ZGY bricked format (*.zgy)	PSpad
4	**Fault**	Fault Polygons	Zmap+ lines (ASCII) (*.*)	PSpad
		Fault Sticks	Zmap+ lines (ASCII) (*.*)	
5	**Isochore**	Thickness	Zmap+ grid (ASCII) (*.*)	PSpad

3.2.2.1 <u>PSpad Editor Format for Well Data</u>

- Well Header

When using PSpad editor well header data are arranged in order as indicated in Fig.3.0:

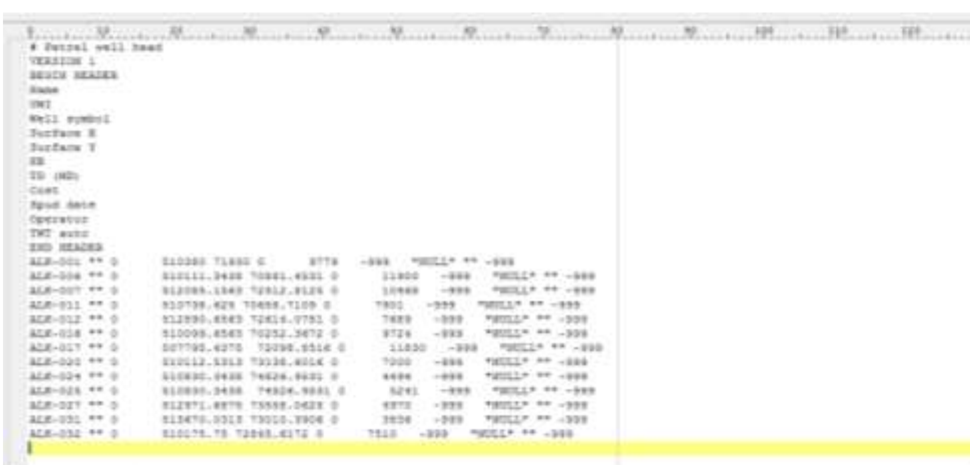

Petrel well head
VERSION 1
BEGIN HEADER
Name
UWI
Well symbol
Surface X
Surface Y
KB
TD (MD)
Cost
Spud date
Operator
TWT auto
END HEADER

Figure 3.0: The well headers data file open in a PSpad window

- Well Path/Deviation, Well Logs and Check Shots

The PSpad formats for creating well path/deviation, well logs and check shots are similar to well header. Like well header data, these data were arranged in column (below the header) as illustrated in Table 11. Also, snapshots of the well path/deviation, Well Logs and Check Shots data respectively in PSpad editor are given below to demonstrate arrangement order:

Table 11: PSpad format for Well Path/Deviation

DATA CATEGORY	HEADER FORMAT	ARRANGEMENT BELOW HEADER								
Well Paths/Deviations	WELL TRACE FROM PETREL	MD	X	Y	TVD	DX	DY	AZIM	INCL	DLS
	# WELL NAME									
	# WELL HEAD X-COORDINATE									
	# WELL HEAD Y-COORDINATE									
	# WELL KB									
	# WELL TYPE									
	# MD AND TVD ARE REFERENCED									
	# ANGLES ARE GIVEN IN DEGREES									

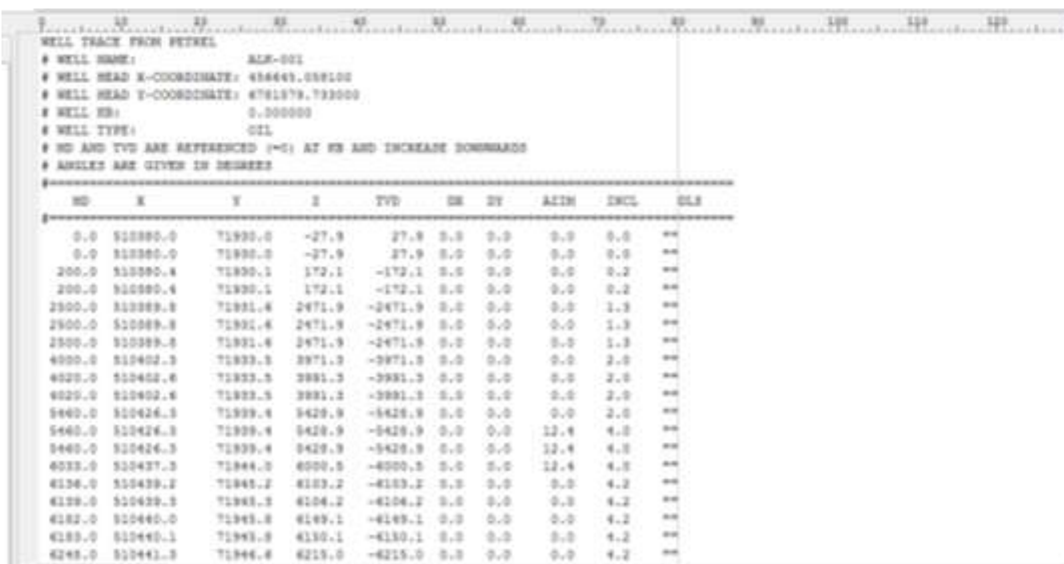
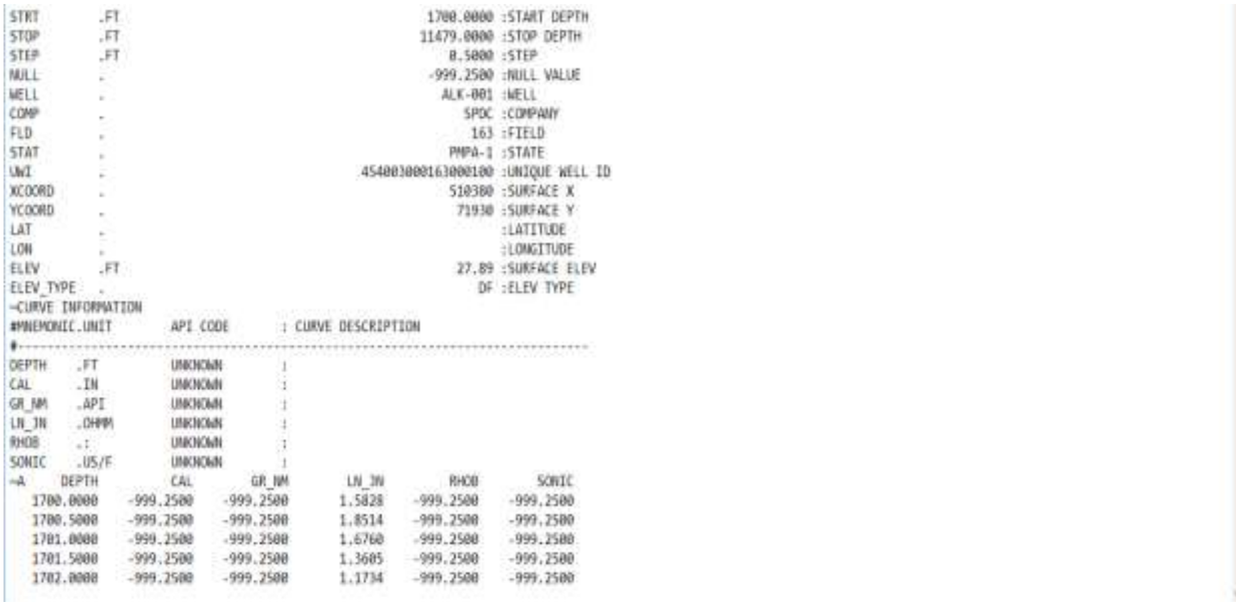


Figure 3.1: The well path/deviation data file opened in a PSpad window



```
STRT      .FT                              1700.0000 :START DEPTH
STOP      .FT                             11479.0000 :STOP DEPTH
STEP      .FT                                 0.5000 :STEP
NULL      .                                -999.2500 :NULL VALUE
WELL      .                                  ALK-001 :WELL
COMP      .                                     SPDC :COMPANY
FLD       .                                      163 :FIELD
STAT      .                                   PMPA-1 :STATE
UWI       .                       4540030001630000100 :UNIQUE WELL ID
XCOORD    .                                   510380 :SURFACE X
YCOORD    .                                    71930 :SURFACE Y
LAT       .                                          :LATITUDE
LON       .                                          :LONGITUDE
ELEV      .FT                                  27.89 :SURFACE ELEV
ELEV_TYPE .                                       DF :ELEV TYPE
~CURVE INFORMATION
#MNEMONIC.UNIT       API CODE        : CURVE DESCRIPTION
#-----------------------------------------------------------------
DEPTH    .FT         UNKNOWN         :
CAL      .IN         UNKNOWN         :
GR_NM    .API        UNKNOWN         :
LN_IN    .OHMM       UNKNOWN         :
RHOB     .:          UNKNOWN         :
SONIC    .US/F       UNKNOWN         :
~A     DEPTH        CAL        GR_NM       LN_IN       RHOB       SONIC
   1700.0000   -999.2500   -999.2500      1.5828   -999.2500   -999.2500
   1700.5000   -999.2500   -999.2500      1.8514   -999.2500   -999.2500
   1701.0000   -999.2500   -999.2500      1.6760   -999.2500   -999.2500
   1701.5000   -999.2500   -999.2500      1.3605   -999.2500   -999.2500
   1702.0000   -999.2500   -999.2500      1.1734   -999.2500   -999.2500
```

Figure 3.2: The well log data file for AK-001 opened in a PSpad window

```
C-WELLNAME: AK-001              | ELEVATION:     27.9| 02-Feb-2012  | CORP WELL: 001          UNIQUE_WELLNAME-:AK-001
C----LEASE:                     |WATER_DEPTH:99765.0 |   15:10:15   | CORP MD=11460  TVD=11460  SPUD:          COMP: 1999-12-13 0|
C-OPERATOR: SPDC                |DEPTH_UNITS:   FEET |              | EL=    28  WD=98765  STATUS: PA       PWI:        PS=Min |
C----FIELD: ALAKIRI             | TIME_DATUM:    0.0 |              | SUR LON=   7.0562318  LAT=  4.6492179 X=  510380 Y=  71930 |
C-UNIQUEID: 4540030001630000100 | TIME_SHIFT:    0.0 |USER: Favour.Ja| BHL LON=   7.0570540  LAT=  4.6495202 X=  510471 Y=  71962 |
C SUBDAT|SEISMIC|INTERVAL| AVERAGE| VELOCITY SOURCE:
C  DEPTH|TIME-MS|VELOCITY|VELOCITY| TZ NAME: tz_ak-1
# Petrel CheckShots format
# Not all attributes are necessary.
# i.e. X, Y, and Z can be left out, as they are derived from md and the well
# The attributes can also have a different order than described here
# Lines starting with # are comments
VERSION 1
BEGIN HEADER
Z
TWT
Well Name
END HEADER
     0.0      0.0    "AK-001"
  2522.0 10000.0    "AK-001"
  2558.0 10200.0    "AK-001"
  0.0      0.0      "AK-006"
  3969.0  1176.0    "AK-006"
  4963.0  1430.0    "AK-006"
  6463.0  1788.0    "AK-006"
  0.0      0.0      "AK-007"
   953.1   954.6    "AK-007"
  3953.1  1233.6    "AK-007"
  6653.1  1877.8    "AK-007"
  7663.1  2098.0    "AK-007"
  7743.1  2114.0    "AK-007"
```

Figure 3.3: The check shots data file open in a PSpad window

3.2.2.3 <u>PSpad Editor Format for Non-Well Data (Well Tops, Seismic, Fault, Isochores etc</u>)

In the PSpad format,the non-well data are created following similar arrangement pattern for well data. The tabular and snapshots representations for Well tops illustrate this:

Table 12: PSpad Editor Format for Well Tops and Faults

DATA CATEGORY	HEADER FORMAT	DATA ARRANGEMENT BELOW HEADER												
		REAL X	REAL Y	REAL Depth	REAL Time	STRING Type	STRING Horizon Name	STRING Well Name	STRING Symbol	REAL Measured Depth	STRING Pick Name	STRING Interpreter	REAL Dip Angle	REAL Dip Azimuth
	#Petrel Well Tops													
	VERSION 1													
	BEGIN HEADER													
	REAL X													
	REAL Y													
	REAL Depth													
	REAL Time													
	STRING Type													
Well Tops	STRING Horizon Name													
	STRING Well Name													
	STRING Symbol													
	REAL Measured Depth													
	STRING Pick Name													
	STRING Interpreter													
	REAL Dip Angle													
	REAL Dip Azimuth													
	END HEADER													
		X-Coordinate	Y-Coordinate	Fault Number	Position									
	X-Coordinate													
Faults	Y-Coordinate													
	Fault Number													
	Position													

```
#Petrel Well Tops
VERSION 1
BEGIN HEADER
REAL X
REAL Y
REAL Depth
REAL Time
STRING Type
STRING Horizon Name
STRING Well Name
STRING Symbol
REAL Measured Depth
STRING Pick Name
STRING Interpreter
REAL Dip Angle
REAL Dip Azimuth
END HEADER
510380  71930   -27.9   -10.4   PALZON  PALEO   ALK-001 Unknown 0               0       0
510380  71930   -27.9   -10.4   PALZON  PALEO   ALK-001 Unknown 0               0       0
510380.4        71930.1 172.1   64      MARKER  PALEO_NONE_top  ALK-001 Unknown 200             0       0
510380.4        71930.1 172.1   64      PALZON  PALEO   ALK-001 Unknown 200             0       0
510389.8        71931.6 2471.9  777.4   MARKER  PALEO_P780/P870_        ALK-001 Unknown 2500            0       0
510389.8        71931.6 2471.9  777.4   PALZON  P780/P870       ALK-001 Unknown 2500            0       0
510389.8        71931.6 2471.9  777.4   PALZON  P780/P870       ALK-001 Unknown 2500            0       0
510402.3        71933.5 3971.3  1237.7  MARKER  PALEO_NONE_base ALK-001 Unknown 4000            0       0
510402.6        71933.5 3991.3  1242.3  PALZON  F9600/F9700     ALK-001 Unknown 4020            0       0
510402.6        71933.5 3991.3  1242.3  PALZON  F9600/F9700     ALK-001 Unknown 4020            0       0
510426.3        71939.4 5428.9  1574.9  MARKER  PALEO_P770_top  ALK-001 Unknown 5460            0       0
510426.3        71939.4 5428.9  1574.9  PALZON  P770    ALK-001 Unknown 5460            0       0
510426.3        71939.4 5428.9  1574.9  PALZON  P770    ALK-001 Unknown 5460            0       0
510437.3        71944   6080.5  1712    MARKER  D1000_top       ALK-001 Unknown 6033            0       0
510439.2        71945.2 6103.2  1732.6  MARKER  D1000_base      ALK-001 Unknown 6136            0       0
510439.3        71945.3 6106.2  1733.2  MARKER  D1200_top       ALK-001 Unknown 6139            0       0
510440  71945.8 6149.1  1742.2  MARKER  D1200_base      ALK-001 Unknown 6182            0       0
510440.1        71945.8 6150.1  1742.4  MARKER  D1300_top       ALK-001 Unknown 6183            0       0
510441.3        71946.6 6215    1758.4  MARKER  D1300_base      ALK-001 Unknown 6248            0       0
```

Figure 3.4: The well tops data file open in a Notepad window

3.2.3 **The Modeling Process**

Modeling was carried out using the **Schlumberger Petrel** software to build geological and petrophysical models.

3.2.3.1 **Geo-modeling**

In order to develop a petrophysical model of the AK field, a geological model encompassing structural and stratigraphic models respectively were developed. The geological model was developed from fault and horizon mapping.

To construct the s**tructural model,** fault lines were mapped into seismic section generated from imported seismic data (in SEG-Y format). Faults were mapped in the INLINE direction with increment of 10 units. Fault sticks were converted to fault polygons. Mapped faults run vertically through the software generated seismic section. A total of five major faults were identified and mapped. Fault polygons were then developed from faults mapped on the seismic section. The polygons were built from coordinate data retained in PETREL software after fault mapping. Combining mapped faulted and polygon generated the fault model.

The initial step in constructing **stratigraphic model** is creating horizon. Horizons were mapped with tops serving as guide.To map horizon, horizontal lines tangentially to mapped faults were run through the same seismic section onto which the faults were mapped. Thereafter surfaces were created from mapped horizon after polygon boundary and fault polygons have been defined. By integrating mapped horizons with polygon boundary and fault polygons the stratigraphic model was developed.

A generalized workflow that outlines the paths followed in developing the geological model is shown in Fig. 3.5.

- Loading wells and seismic data sets
- Running Check-shots to view all data in Two-Way Travel Time (TWT) Domain
- Tying Wells to seismic
- Conducting seismic interpretation through fault picking and horizon mapping

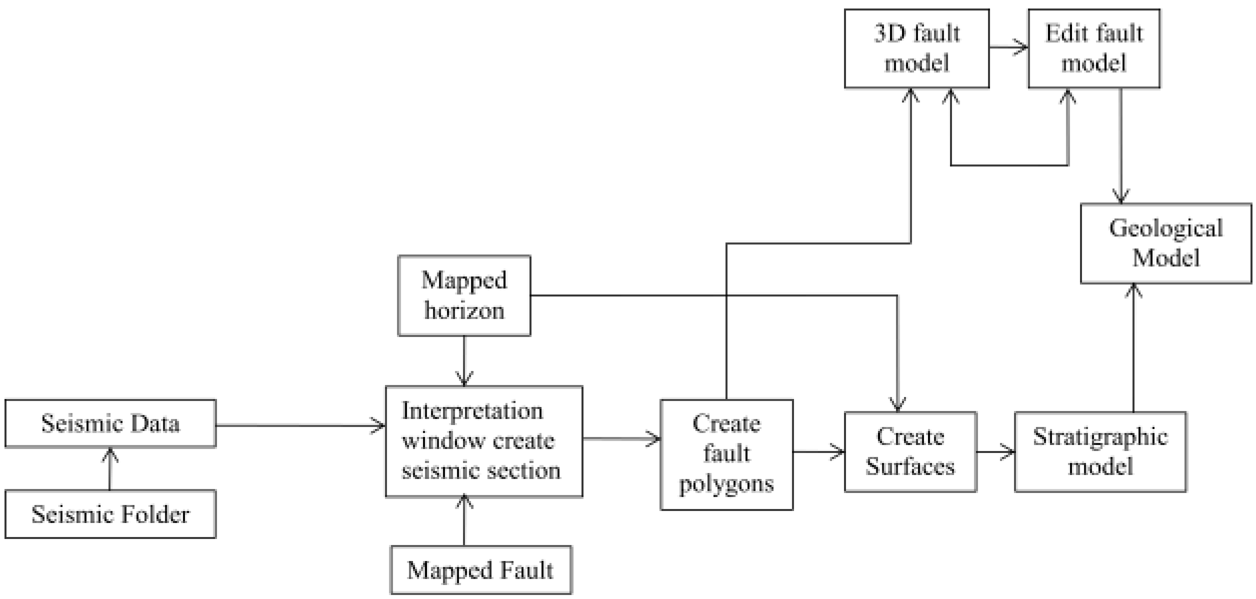


Figure 3.5: Workflow for the Development of the 3D Geological Model

3.2.3.2 <u>Property Modeling</u>

The property grids were obtained by populating the geological model developed with well log data. The 3D grid developed include: Porosity, permeability, water saturation, shale volume and net-to-gross ratio. Using formation parameters generated from log data and basic regional information applicable to the Niger Delta Province enabled the determination of the petrophysical model. For the Niger Delta Province, the following basic cut-offs were used for the estimation of Petrophysical parameters from the existing correlations:

- Formation contains the three shale types- disperse, laminar and structural
- Shale content assumed low
- Cementation factor (m) =1.8
- Water resistivity (R_w) =0.1 and
- Shale resistivity (R_{sh}) = 3.2
- Empirical constant, a, = 2

Procedures for determining each petrophysical models of interest are given below:

Shale Volume (V_{sh}) Model

Step 1: Obtain the minimum Gamma Ray (GRcs) value from the gamma ray log reading. This value is at the left-most deflection value on the gamma ray log. The minimum gamma ray log value represents the region of the formation where there is clean sand.

Step 2: Obtain the maximum Gamma Ray (GR_{sh}) value from the gamma ray log reading. This value is at the right-most deflection on the gamma ray log. The maximum gamma ray log value represents the region of the formation where there is shale.

Step 3: Keep fixed the maximum and minimum gamma ray readings. Compute the shale volume from the varying log readings (GR) by keeping fixed the maximum and minimum gamma ray readings. The shale volume at each interval of logging is determined from:

$$V_{sh} = \frac{GR - GR_{cs}}{GR_{sh} - GR_{cs}}$$

For example, $GR_{cs}$and GR_{sh} were determined to be 19 and 150 API respectively. These values were kept constant throughout the calculation for shale volume. Thus with varying GR reading the resulting equation for the determination of shale volume was:

$$V_{sh} = \frac{GR - 19}{150 - 19}$$

GR is obtained from wells with gamma ray reading from which Vsh is calculated.

Water saturation (Sw) Model

Step 1: From V_{sh} values obtained, substitute 1.8 for cementation factor (m), 0.1 for water resistivity (R_w), 2 for empirical constant a and 3.2 for shale resistivity (R_{sh}) into the Simandoux equation as given below:

$$\mathbf{Sw} = \left(\frac{aR_w}{2\phi^m}\right)\left[-\left(\frac{V_{sh}}{R_{sh}}\right) + \left(\left(\frac{V_{sh}}{R_{sh}}\right)^2\right) + \left(\left(\frac{4\phi^m}{aR_wR_t}\right)^{.5}\right)\right]$$

Step 2: Compute Sw. V_{sh} is the only varying parameter. For each V_{sh} value there is a corresponding Sw value generated and saves by the software.

Porosity (ϕ) Model

Step 1: Record 2.65g/cm^3 for sandstone grain density, 0.8 g/cm^{3}for fluid density. The density log values are the bulk density values.

Step 2: Keep the sandstone grain density and fluid density values constant. Only the bulk density values from the well logs are varying. Compute the density porosity from:

$$\phi = \frac{2.65 - \rho_b}{2.65 - 0.8}$$

Permeability (K) Model

Step 1: Determine the Reservoir Quality Index (RQIsh) from equation 5a.

Step 2: Substitute the value of step1 into the equation below and determine permeability (K). Note that Rw, a and m values are 0.1, 2 and 1.8 respectively.

$$RQI_{sh} = \left[0.314\left(\frac{K}{\phi(1-V_{sh})R_w}\right)^{0.5}\right]$$

To determine K, make K the subject.

Net-to-Gross Ratio Model

Determine the Net-to-Gross sand (Net Sand Distribution) by subtracting the fraction of shale volume from unity as indicated below.

Net-to-Gross Sand = 1- V_{sh}

Three steps were followed in building the petrophysical models using PETREL. These steps are shown in the workflow in Fig. 3.6. The following processes were followed:

- up-scaling the well log data to achieve data scale compatibility between well log and seismic data. Well logging, as it may be recalled, covers narrow area but gives better resolution. When evaluated on a geological scale, well log data are mesoscopic as opposed to seismic data which are gigascopic given the extensive area of coverage of the seismic activities**.**
- Geo-statistics was performed using Sequential Gaussian Simulator (SGS):

- To remove one-dimensional trend
- To determine the nugget, sill and range for each parameter
- To determine the azimuth and direction of property variation within the 3D static model

- Adjustment of maximum, minimum and vertical variations so as to minimize the uncertainties of the estimations. Each grid cell within the 3D geological model was then populated with average reservoir properties to optimize performance predictions.

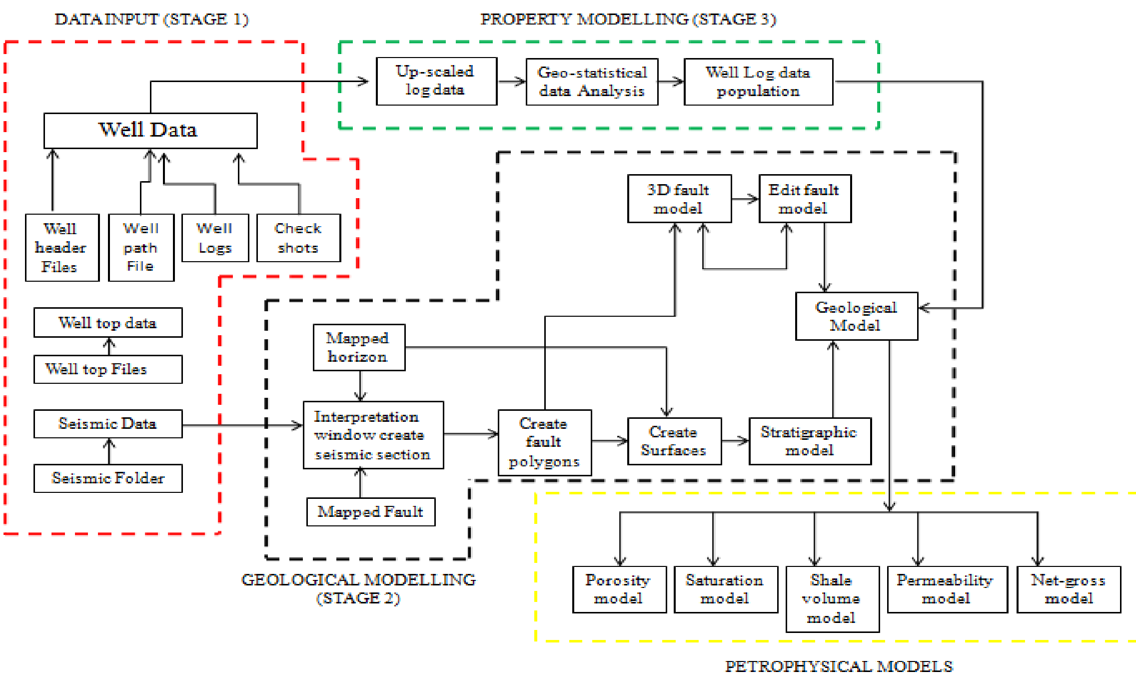


Figure 3.6: Stages in Workflow development of petrophysical models

CHAPTER 4

RESULTS AND ANALYSIS

4.1 Wells Display

Well data for thirteen wells were used in conducting the research. Their import generated the 3D displays shown in Fig. 4.0 through 4.3. when the 3D window of the PETREL software was activated. The check to the left of the **Wells** folder toggles the display of the wells. Once the **Wells** folder is checked, the wells will be displayed as vertical sticks in the 3D window. If the wells are not shown in the window, the **View All** icon is clicked from the **3D Buttons** toolbar as an alternative to display wells.

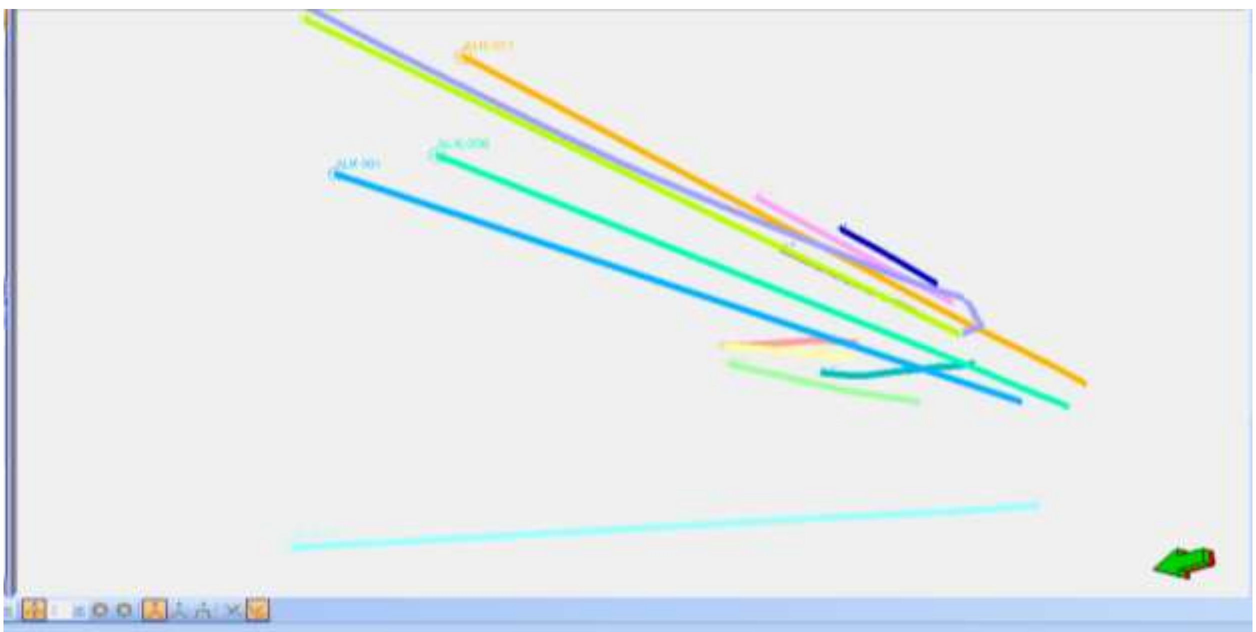


Figure 4.0: The Thirteen Wells of the AK Field Displayed in 3D Window

4.2 Well Tops Display

The import of well tops data generated the display in 3D window as shown in Fig. 4.1.

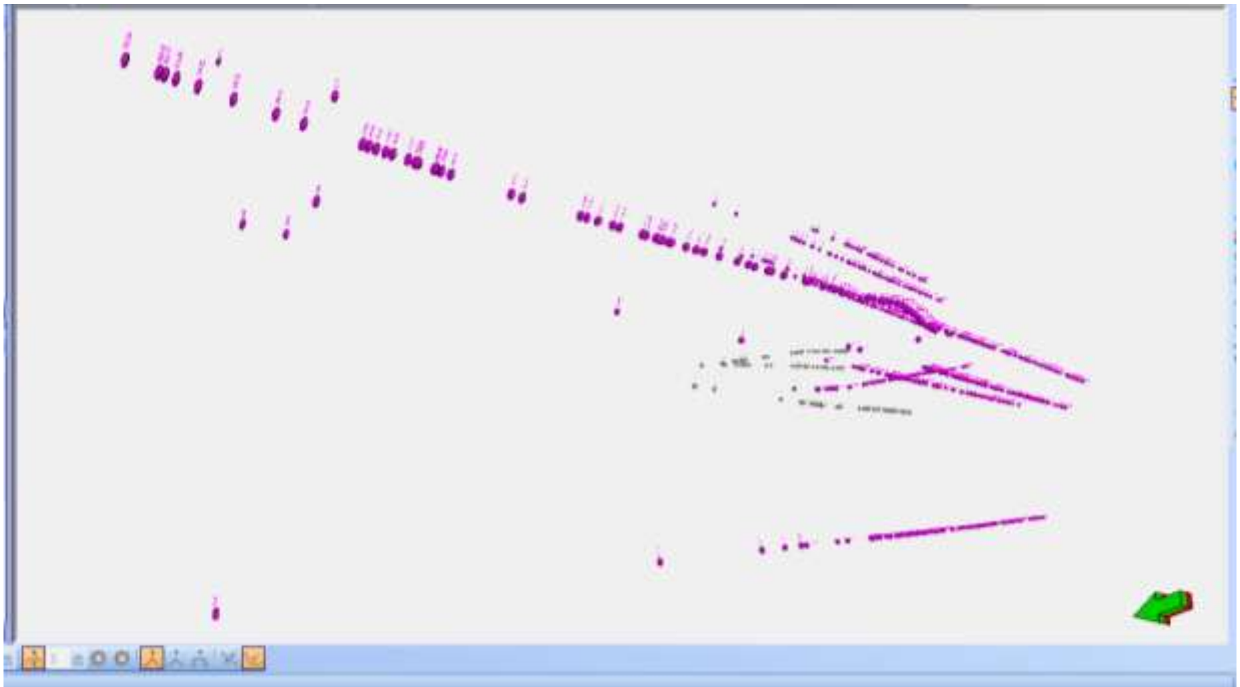


Figure 4.1: Well Tops for deviated wells Displayed in 3D Windows

4.3 <u>Outcome Model</u>

The modeling process was designed to generate petrophysical models that describe reservoir properties from well and seismic data sets. To develop property models, geological model had to initially be built.

4.3.1 <u>Geological Model</u>

The geological model was developed by combining structural and stratigraphic details. From seismic data, the seismic section with major faults label 1 to 5 in Fig.4.2 was generated.

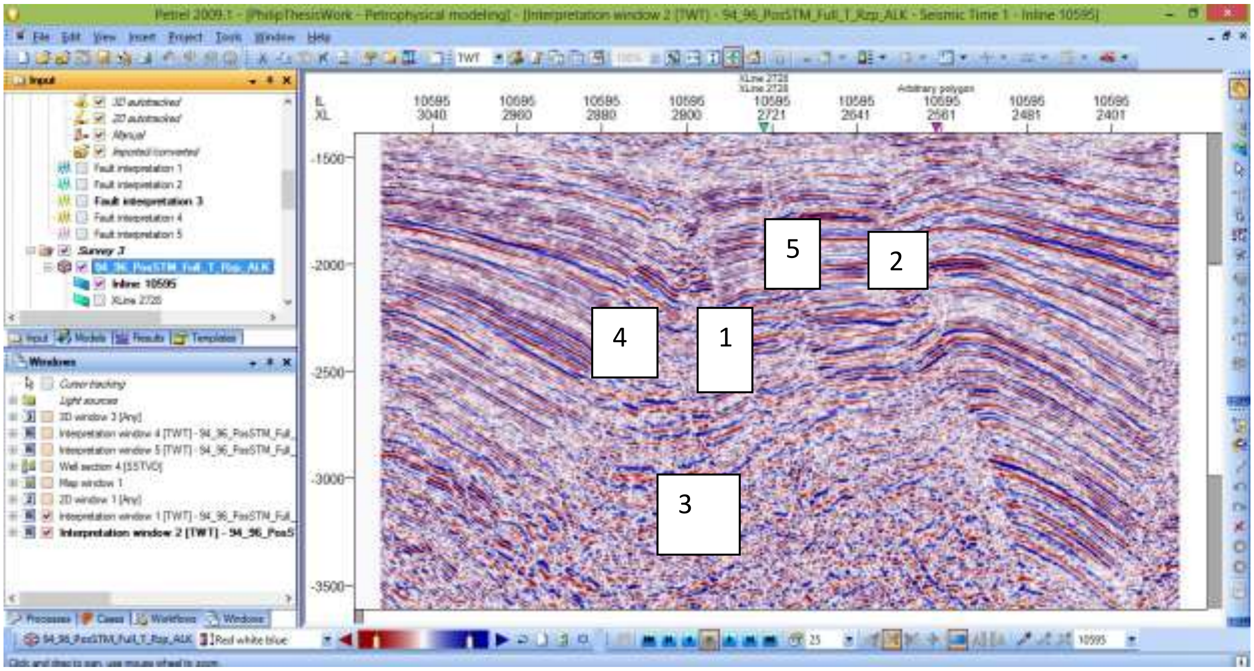


Figure 4.2: Seismic Section with five designated faults displayed in 3D Interpretation Window

Figure 4.3 shows faults mapped across seismic section. Here at least four faults are shown.

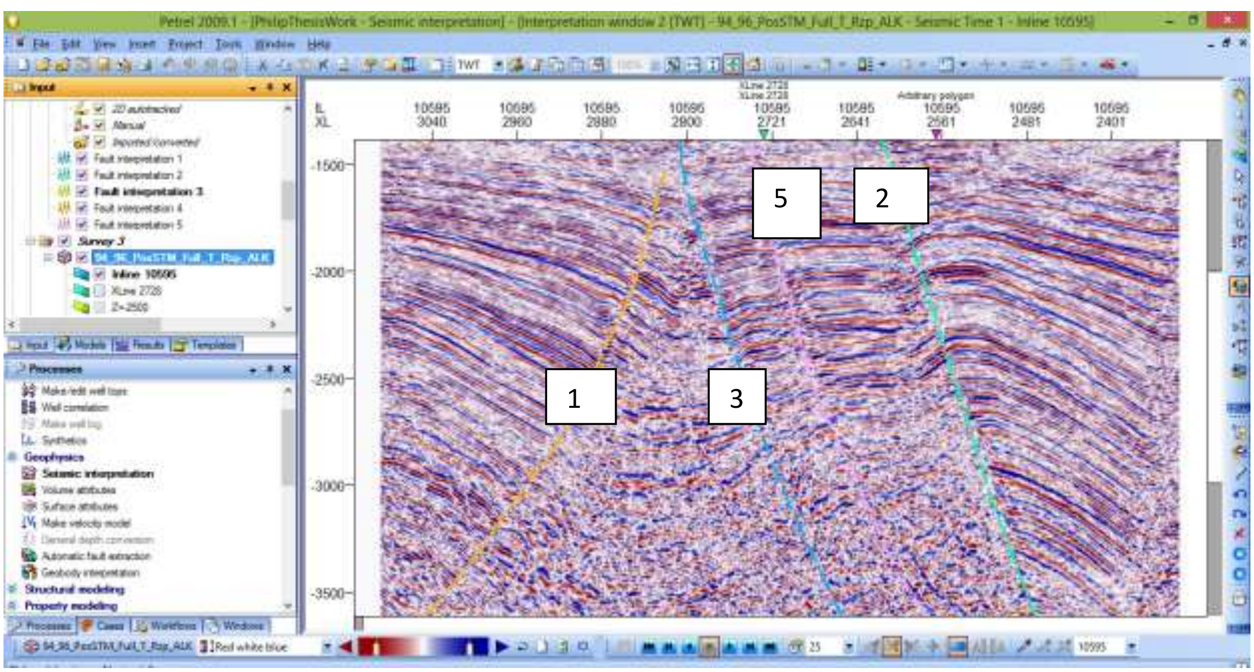


Figure 4.3: Fault Lines Mapped Across Seismic Section

Figures 4.4 and 4.5 revealed the 3D displays of mapped faults and fault polygon**.**

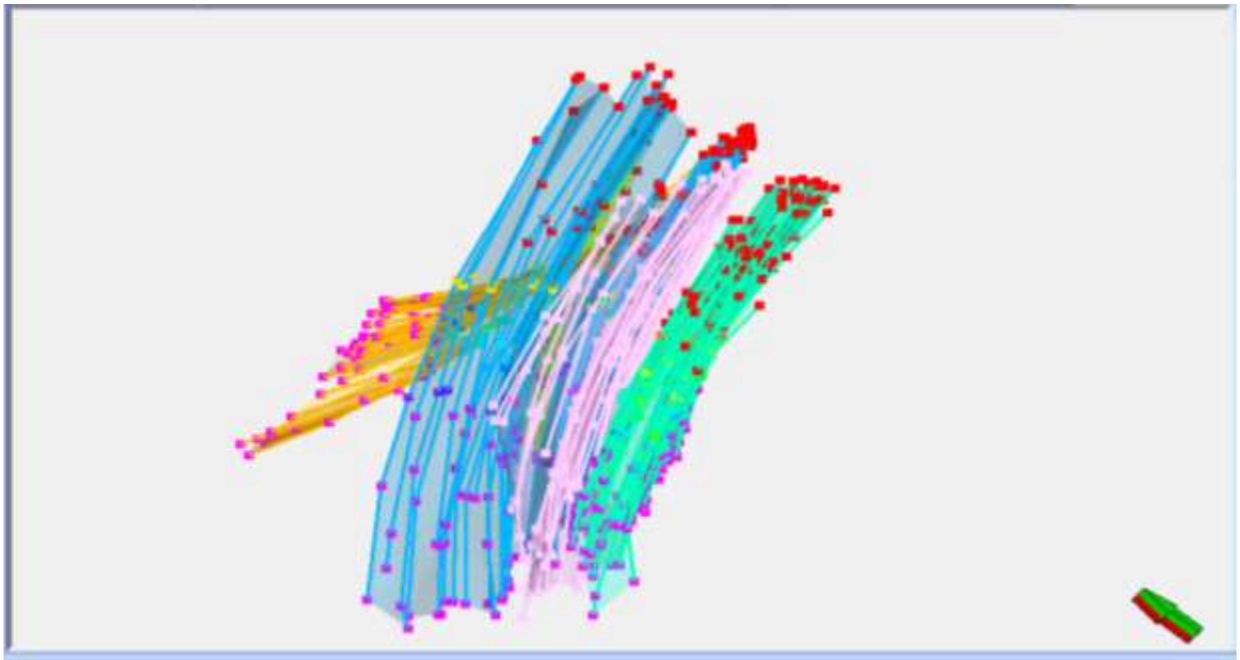


Figure 4.4: 3D Window display of Five Mapped Faults

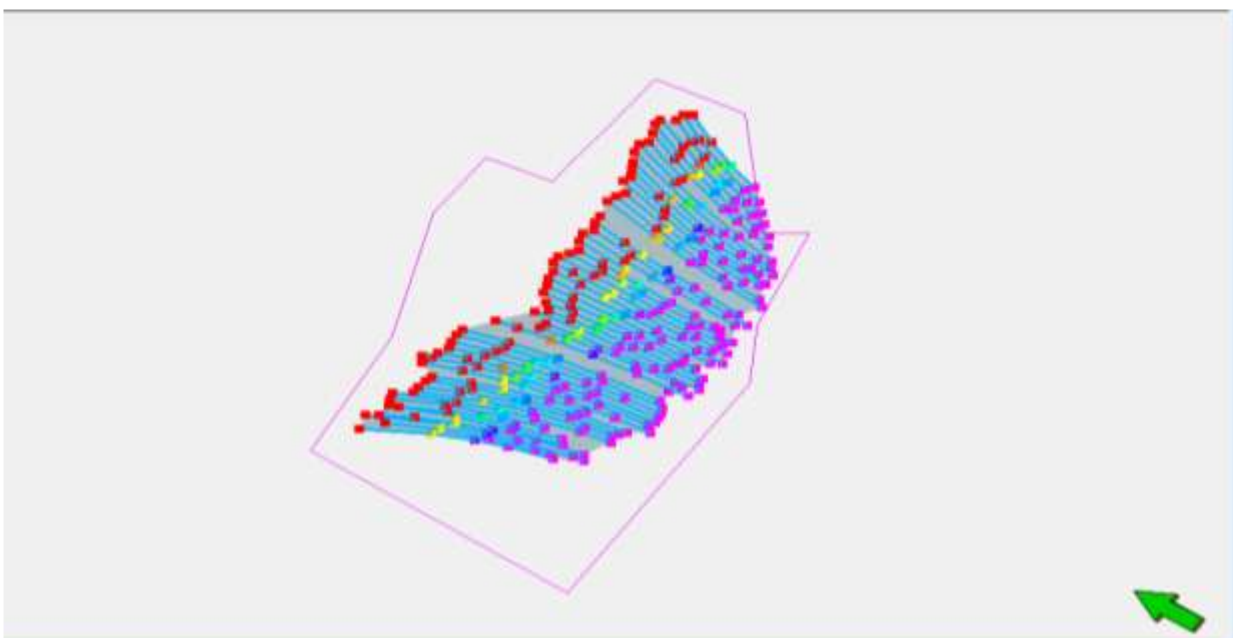


Figure 4.5: Faults and Fault Polygons displayed in 3D window

Gridded fault or structural model generated from mapped faults and fault polygons is shown in Figure 4.6.

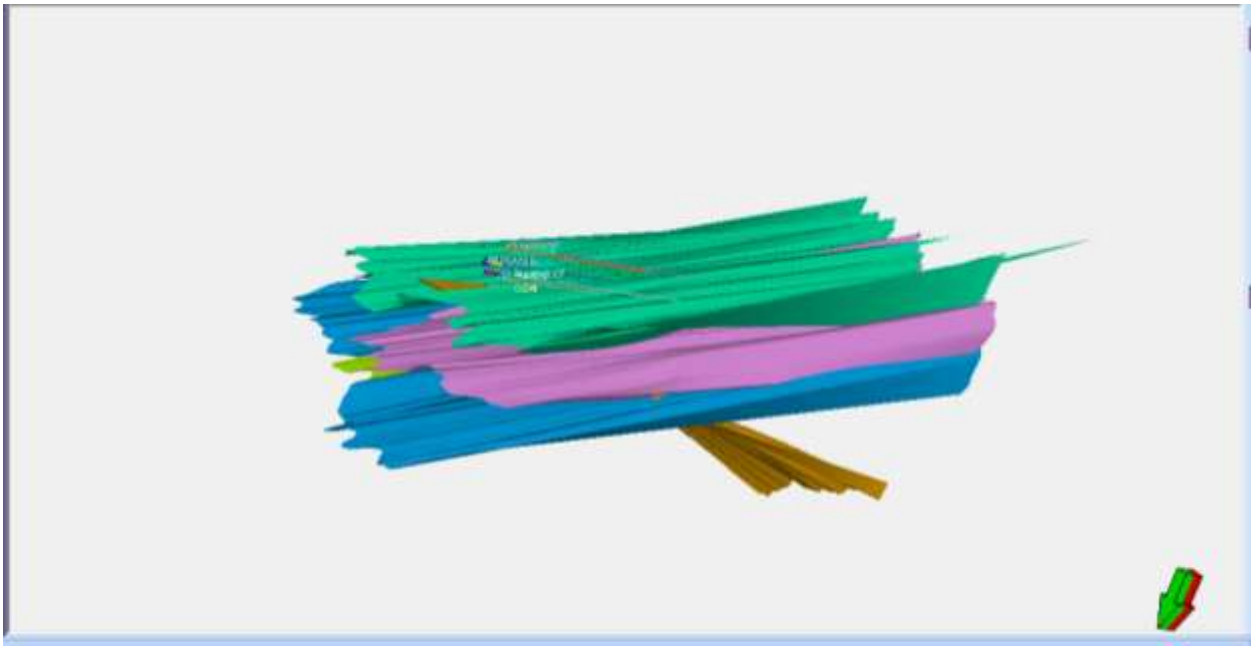


Figure 4.6: Gridded Fault/ Fault Model. (Structural Model)

The stratigraphic model was developed from mapped horizons with formation tops serving as guide. Figures 4.7 through 4.9 show the 3D display of mapped horizons and surfaces.

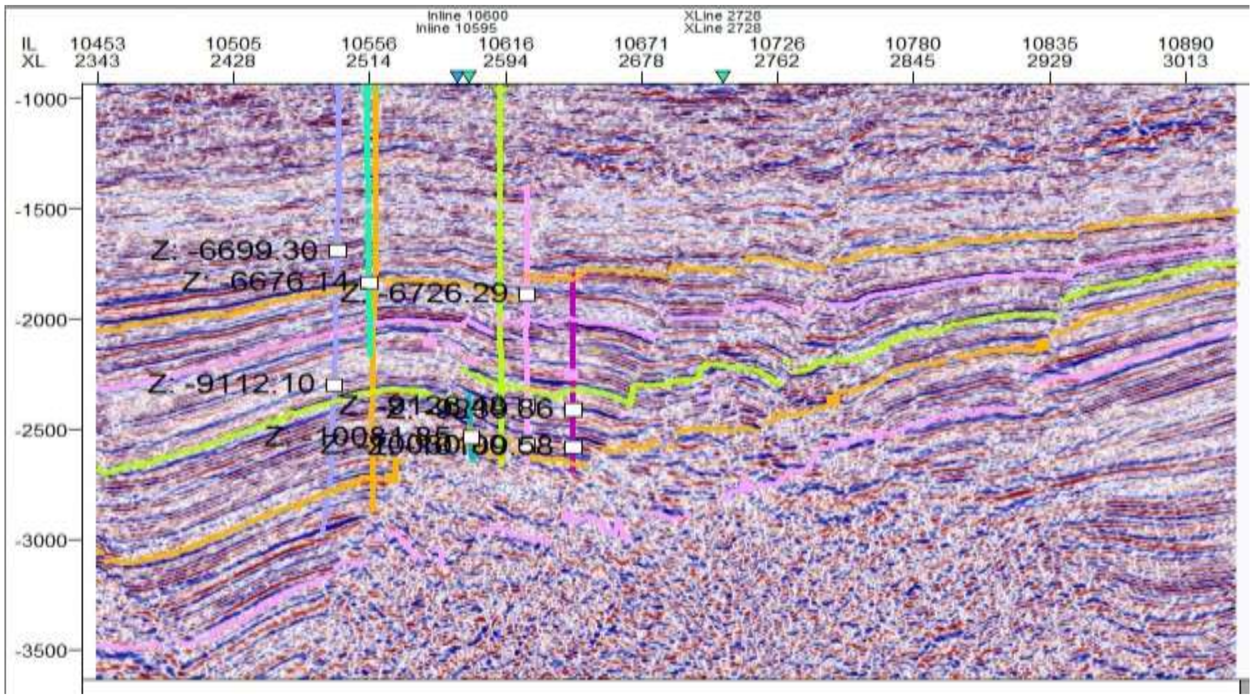


Figure 4.7: Seismic section showing some major mapped horizons (Stratigraphic Tops) and Faults with some well Bores

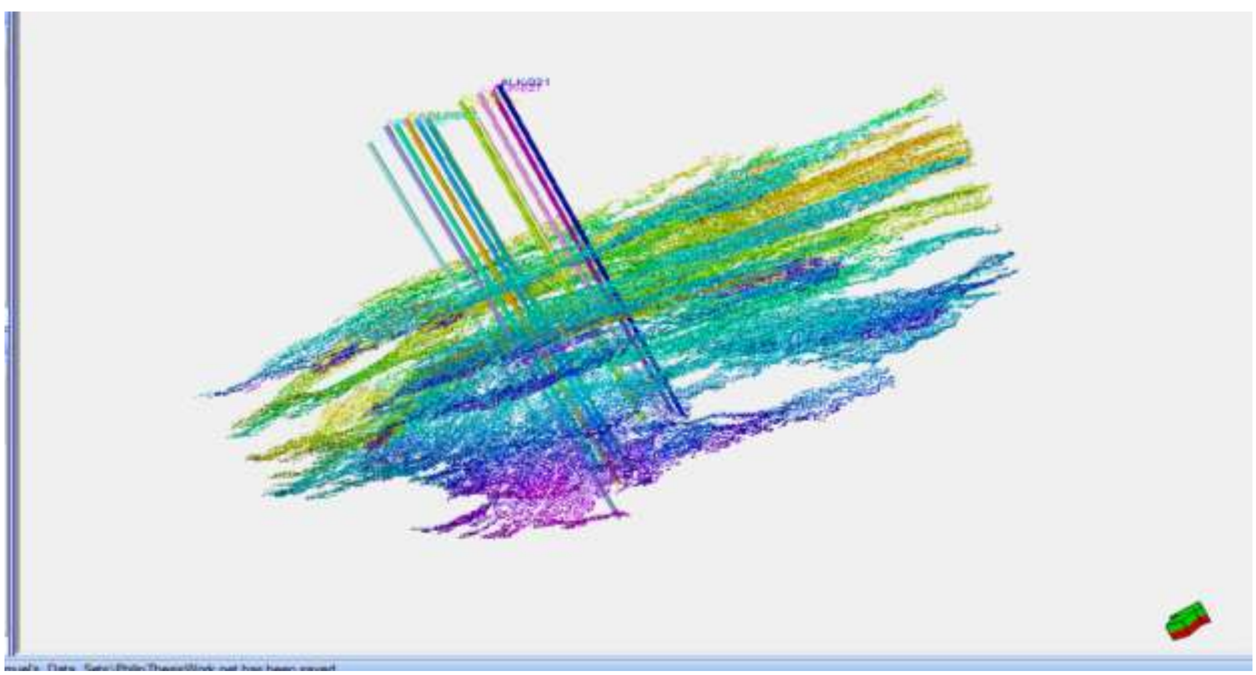


Figure 4.8: Un-Gridded Mapped Horizons (Stratigraphic/Reservoir Tops)

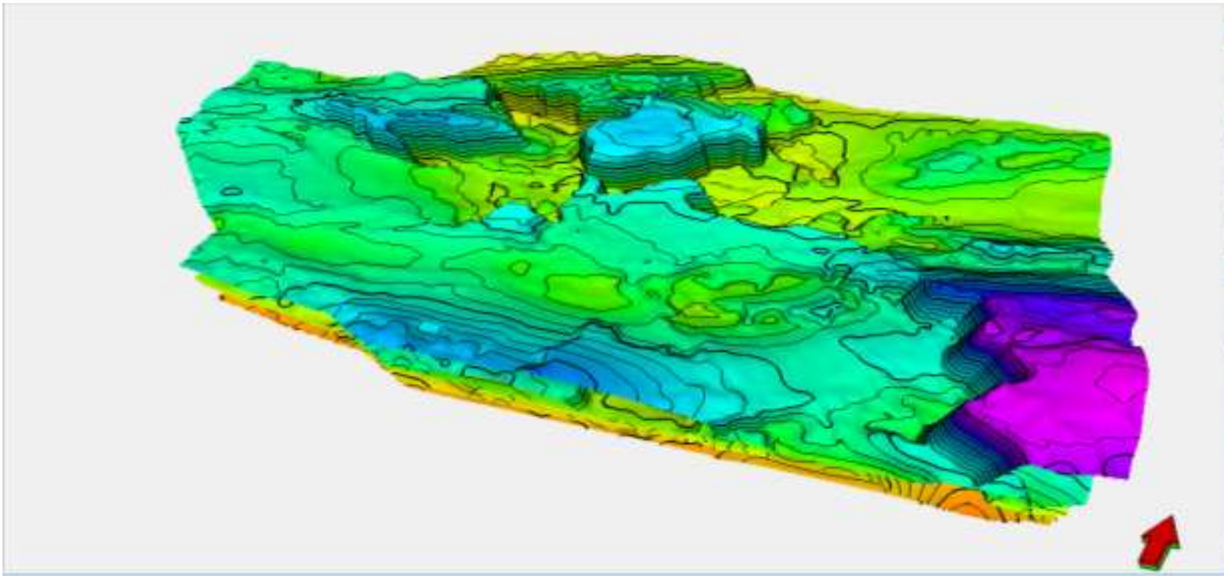


Figure 4.9: 3D Display of Surfaces constituting the formation

The Geological model resulting by combining structural and stratigraphic models is shown in Figure 4.10.

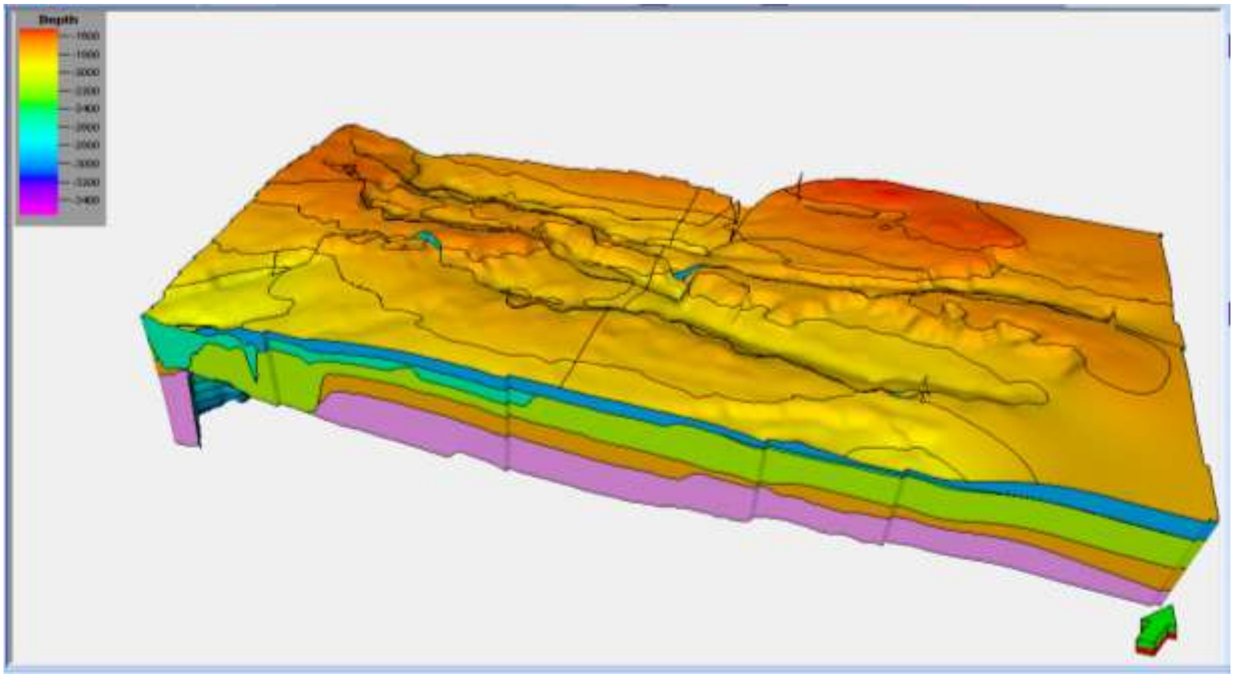


Figure 4.10: Geological Model Developed from Structural and Stratigraphic Frameworks

4.3.2 <u>Property Models</u>

Following the workflow described in Chapter 3, porosity, water saturation, permeability, shale volume and net-to-gross models were developed.

4.3.2.1 <u>The Porosity Model</u>

Investigation of the porosity model revealed a range of porosity between 20 to 40 percent for the AK oil field. This values indicating possible hydrocarbon pore volume with well interconnected pore spaces and water-wet reservoir rocks, which permit high reservoir deliverability.

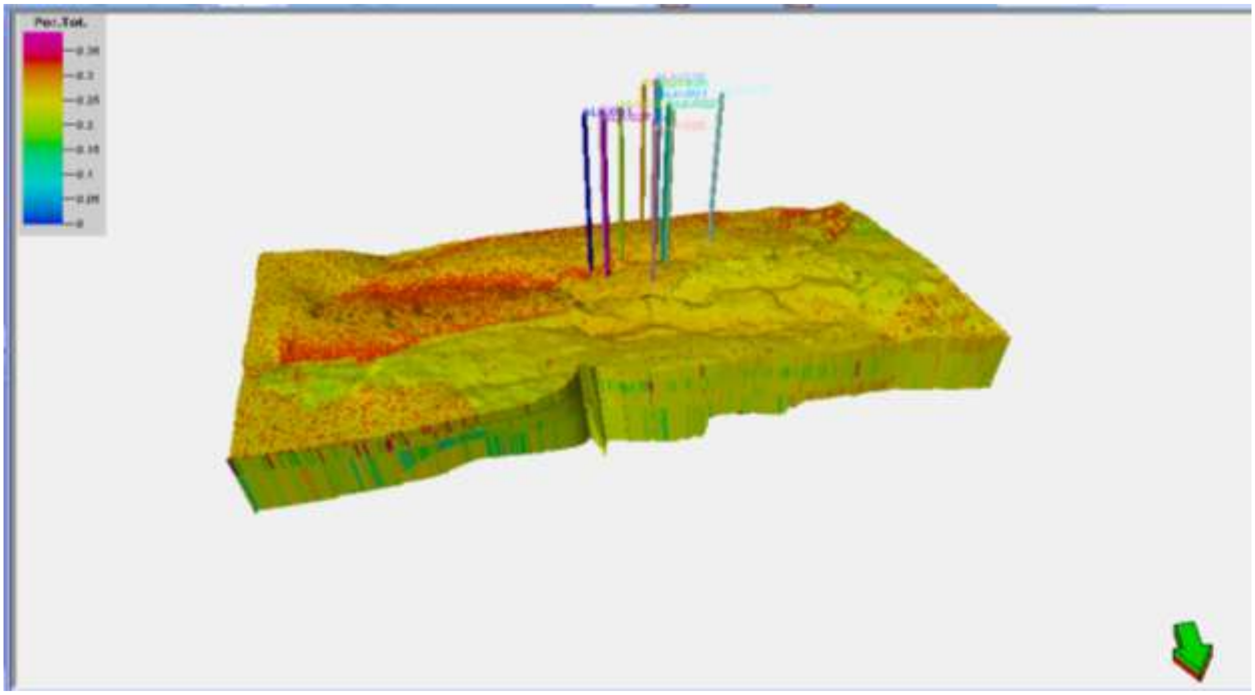


Figure 4.11: Porosity Model

4.3.2.2 <u>The Water Saturation Model</u>

Water saturation for the AK oil field was estimated to range between 10 to 35 percent. Regions with water saturation above 35 percent were considered Aquifer. See the legend for the water saturation distribution within the reservoir. As observed, at locations north-west, south-west and south-east, water saturations approaching 100 percent are encountered thus making it infeasible for the hydrocarbon production.

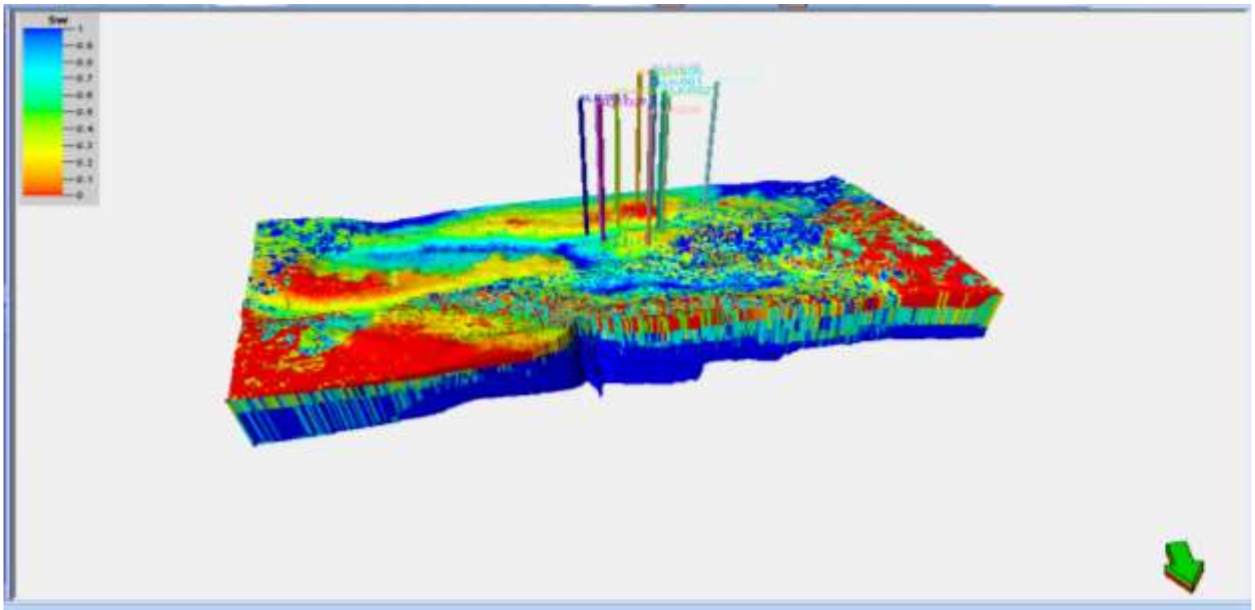


Figure.4.12: Water Saturation Model

4.3.2.3 <u>The Shale Volume Model</u>

Shale volume for the AK oil field indicates estimate of 20 to 40 percent at wells location. This indicates good productive zone with clean sand distribution.

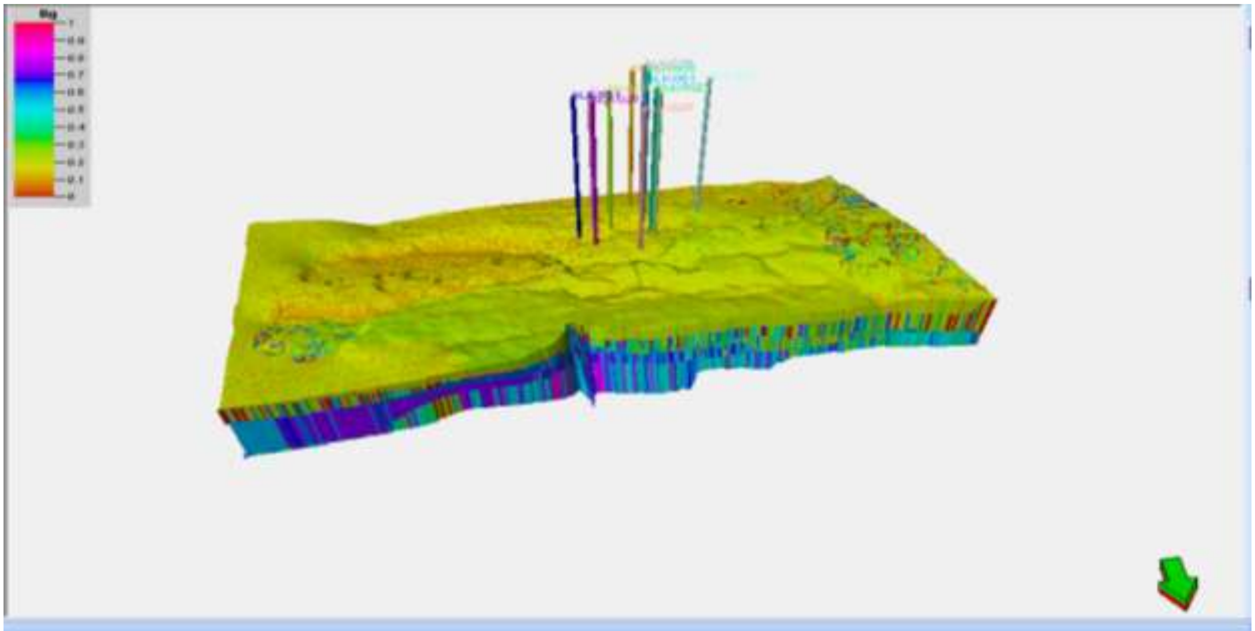


Figure 4.13: Shale Volume Model

4.3.2.4 <u>The Permeability Model</u>

Investigation of the permeability model revealed reservoir permeability of 10 to 100mD at wells location. At the north-east location of the wells, permeability is high between 100 to 1000 mD. With good hydrocarbon pore volume, high reservoir deliverability is expected within the producing zone of the reservoir.

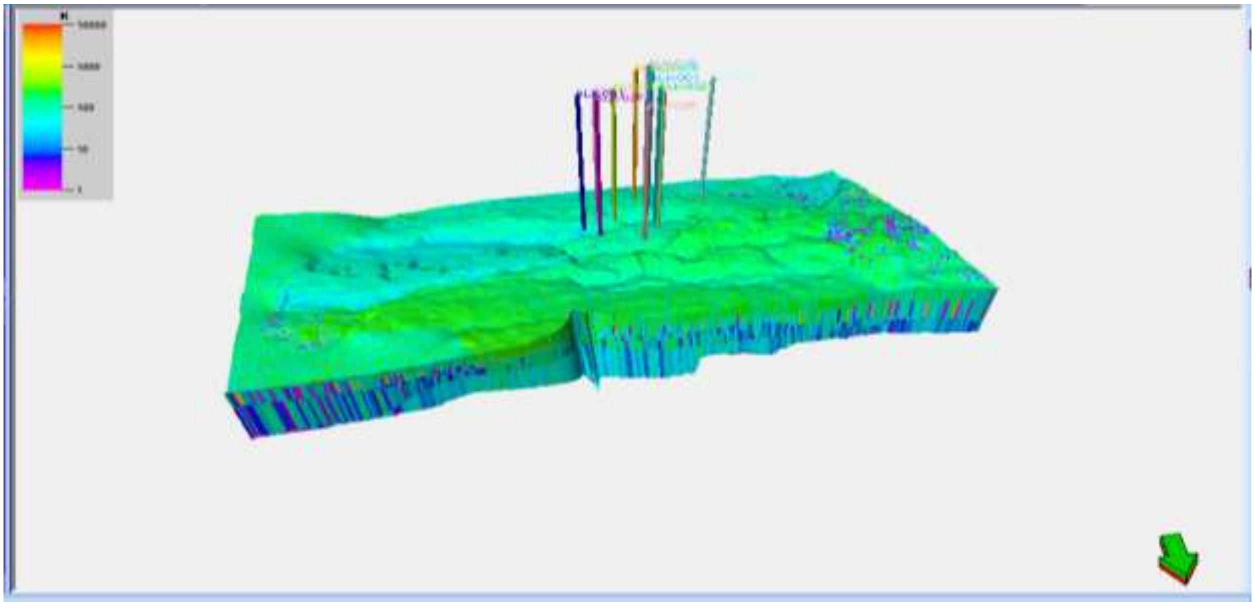


Figure 4.14: Permeability Model

4.3.2.5 <u>Net-to-Gross Ratio Model</u>

Net-to-gross estimates range from 60-80 percent. This indicates a relative large hydrocarbon zone when compared with the shale fraction.

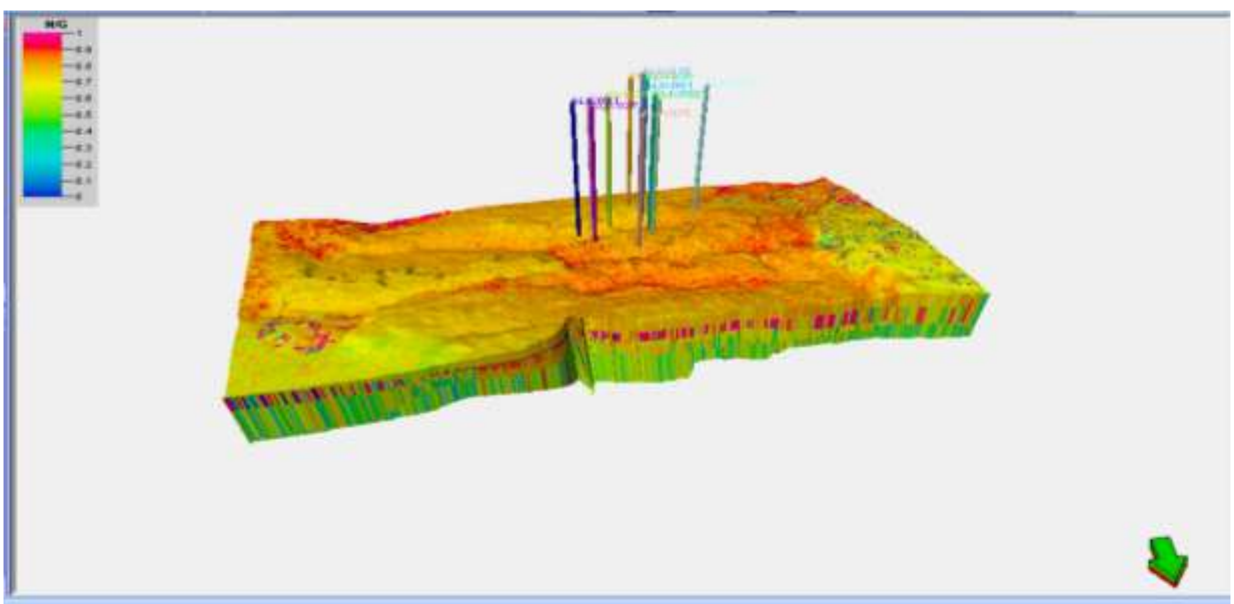


Figure 4.15: Net-to-Gross Model

Table 13 summarizes the estimates of reservoir properties as determined from the generated property models.

Table 13: Petrophysical Property values of the AK Field from modeling

No.	**Property**	Value **(Range)** obtained from Model based on the location of wells in the field
1	Porosity	25 - 35 %
2	Water Saturation	10 - 35 %
3	Shale Volume	20 - 40 %
4	Permeability	10 - 1000 mD
5	Net-to Gross	60 -80 %

4.4 <u>Graphical Interpretation of Intra-Reservoir Properties</u>

Three graphs were obtained to further explain the relationships between petrophysical/reservoir properties.

From Fig. 4.16, net-to-gross increases as depth decreases. At depth of 2200 m (7,218 ft approximately) a net-to gross of 0.56 (56% sand thickness) is observed. As depth of 1800m (5,906 ft approximately), a net-to-gross of 0.96 is attained. This trend indicates that the reservoir can be predicted to be located at relative shallow depth where higher oil recovery is likely. Increase field performance is likely to occur at lower depth.

Given the location of the production zone (where the reservoir is likely to be found), it would be economically viable if wells were drilled no deeper that 7,500 ft.

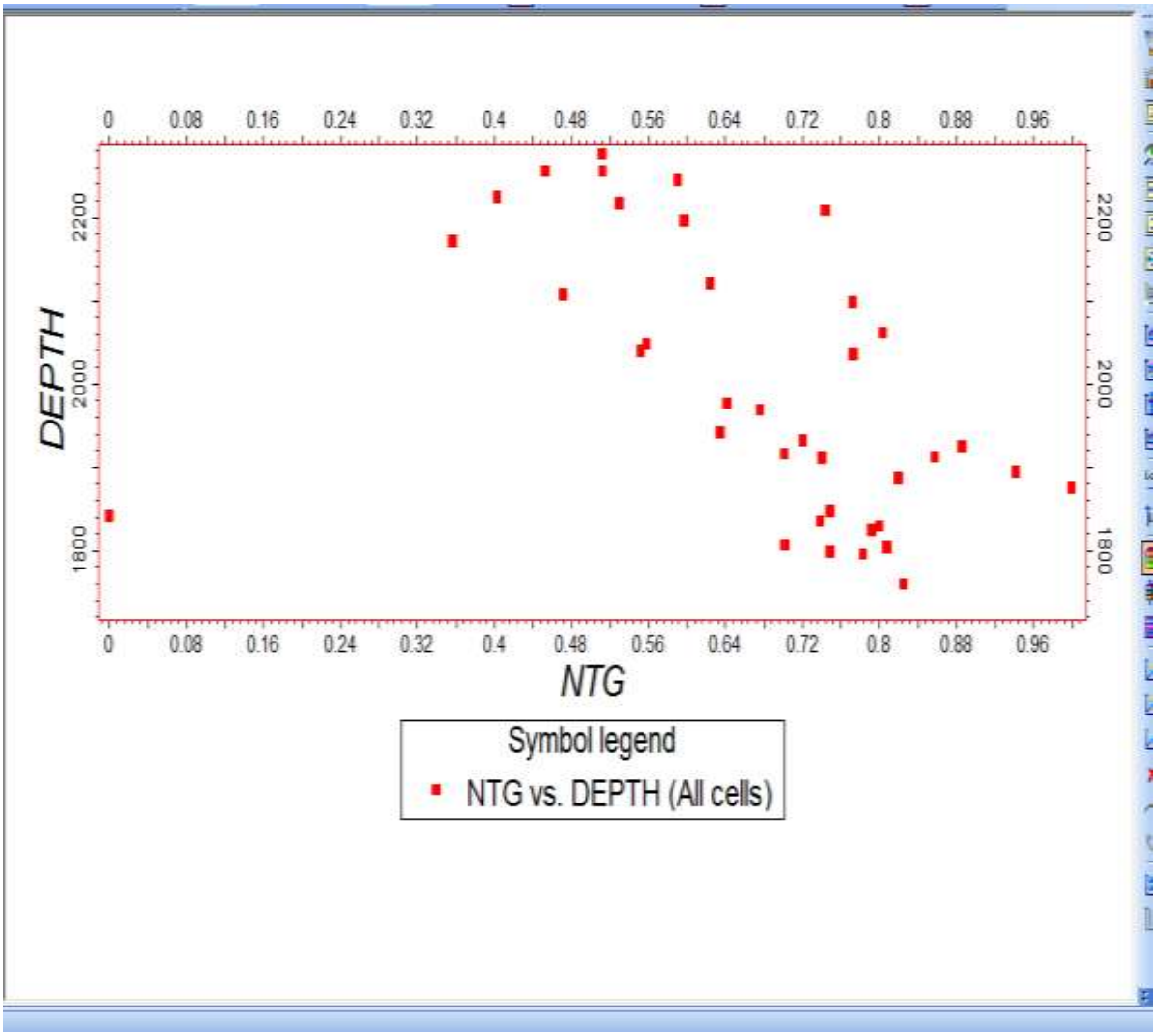


Figure 4.16: Graph of Net Sand Thickness versus Depth

In Fig. 4.17, the plot the depth versus porosity is shown. As observed, at depth greater than 2200 m, porosity of about 18% is attained. This in part could be due to overburden which brings about shrinkage in void spaces of the reservoir rock as a result of the weight of overlying sediments. Porosity increases further down the curve (that is at lower depth). It is likely that at depth beyond 2200m no production interval could be encountered.

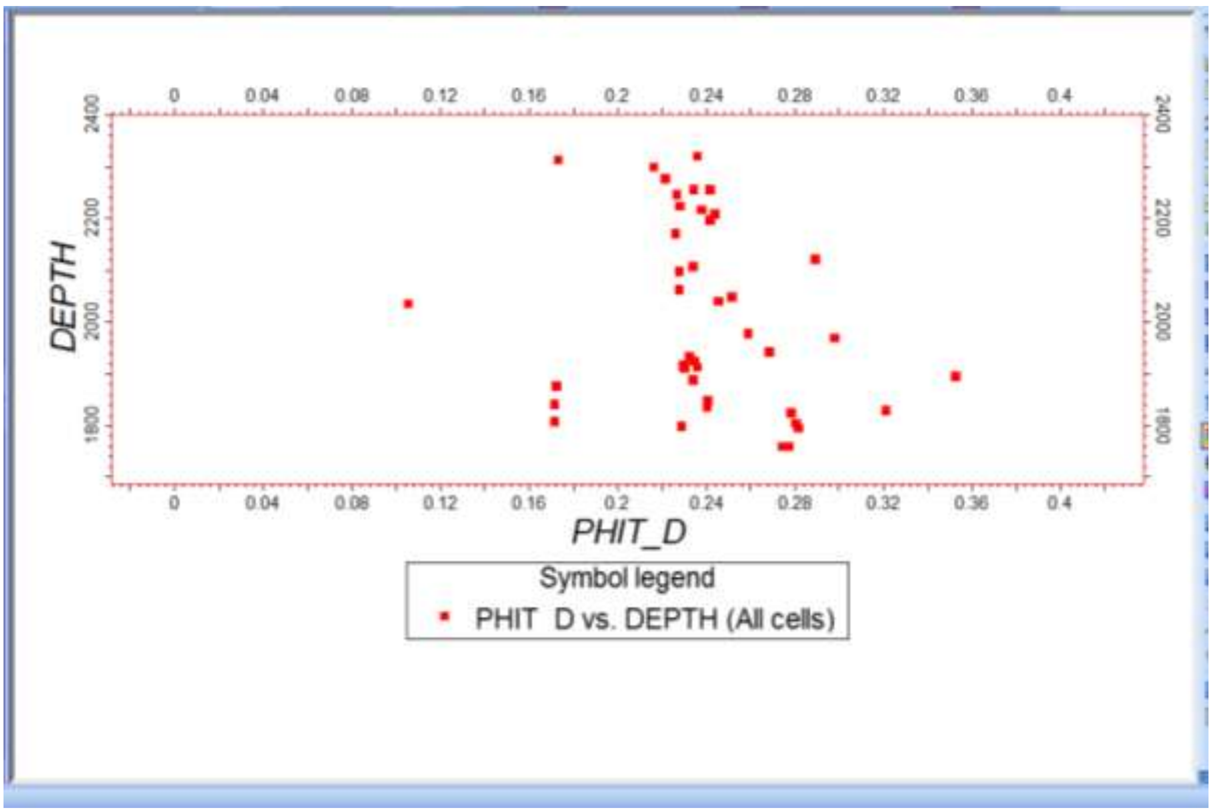


Figure 4.17: Graph of Porosity versus Depth

CHAPTER 5

Conclusions and Recommendations

From the result of this study, the following conclusion can be made:

- Through integration of seismic and well data a better reservoir description was achieved.
- The result from the petrophysical analysis indicated that the field average porosity, water saturation, shale volume, permeability, and net-to-gross respectively are: 30%, 22.5%, 27.5% 505 mD and 70%.
- These values are typical of the Niger delta formation and can inform the basis for technical decision of developing the AK field.
- Reservoir characterization by integrating data from various sources can significantly reduce uncertainty in the estimation of the hydrocarbon volumetric upon which most of the investment decisions are made.

It is therefore recommended that

- The developed models be validated/calibrated by history matching
- Detailed economic evaluation be carried out to establish the economic viability of the field.

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