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HYDROCARBON VOLUME ESTIMATION AND DEVELOMENT STRATEGY OF THE APPRAISAL CANDIDATE RESERVOIRS (A, B, C- D AND E) IN THE UTU FIELD

BY

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CERTIFICATION

This is to certify that this project was carried out by **CALISTA NATACHI IROMAKA,** University of Benin, PG/PSC/1514380, during her internship in the Shell Petroleum Development Company of Nigeria (SPDC) and submitted to the Center of Excellence in Geosciences and Petroleum Engineering, University of Benin, Benin City.

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DEDICATION

This project is dedicated to the Almighty God for his goodness and infinite mercies towards me who in his wisdom brought me thus far in good health of mind and body and to my beloved Parents High Chief and Lolo John Iromaka and to my siblings for being there for me.

ACKNOWLEDGEMENT

Firstly, I would like to thank God almighty for his faithfulness and seeing me through. He started this journey and he has also finished it to him alone be all the glory, Amen.

My profound gratitude goes to my parents and siblings for their, love, support and encouragement throughout my program.

I would like to acknowledge the entire management of Center of Excellence especially the Director; Prof. Joseph O. Ebeniro, Dr. Imasuen, Prof. Godfrey Ariaeve, Mr. Alex for their immense contributions towards the success of my program at the center.

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LIST OF ABBREVIATIONS

AG – Associated Gas

BScf – Billion Standard Cubic Feet DHI –
Direct Hydrocarbon Indicator E & P –
Exploration and Production FGIIP –
Free Gas Initially In Place GOC – Gas-
Oil Contact
GRV – Gross Rock Volume GWC –
Gas- Water Contact
MMSTB – Million Stock Tank Barrel NTG –
Net-to-Gross
PSDM – Prestack Depth Migration
RTM-Reverse time migration
PVT – Pressure Volume and Temperature STOIIP –
Stock Tank Oil Initially In Place

ABSTRACT

With continuous increase in demand for hydrocarbon resources, hydrocarbon estimation, reservoir modeling and uncertainty analysis have become increasingly important for field development optimization. A realistic reservoir description is vital for optimal exploitation of a field which also requires reservoir characterization, modeling and quantification of uncertainties. These uncertainties are mitigated using an integrated approach from wide range of disciplines ranging from Geophysics to Reservoir Engineering.

Hence, this study was focused on accessing, identification and mitigation of uncertainties associated with structure, fluid contact, lateral sand development and reservoir properties. The structural uncertainty was resolved through detailed structural interpretation, fluid contact uncertainty was resolved through amplitude extraction and fluid contact estimation, lateral sand development uncertainty was resolved using acoustic impedance volume from seismic while reservoir properties uncertainties were resolved using inversion method.

A structural framework was generated from structural interpretation result which served as input to the static model, porosity volumes were generated using inversion method also serving as an input to the static model and fluid contact estimation results were used for volumetric computation by the PG and RE respectively which played a crucial role in Production forecast and economic analysis. A generic depth uncertainty analysis of 0.5% was used to compute low case and high case values. The quick-look economics result shows that the project is economically viable with a positive NPV for the five reservoirs (A, B, C, D and E)

CHAPTER ONE

1.1 INTRODUCTION

Reservoir characterization and reserve estimation depends on various petrophysical parameters with wide range of uncertainties. For proper field development, these parameters and their uncertainty ranges must be taken into consideration. Hence, the goal of an E&P company is to extract producible hydrocarbon in an environmental friendly, socially responsible and economically viable manner.

Proper hydrocarbon estimation, reservoir management and field development planning is extremely important in field development project for maximizing the economics of the field which requires accurate reservoir characterization.

This entails detailed testing of reservoir properties using an integrated approach to the geological understanding of the depositional systems and petrophysical properties and controls on fluid flow in a reservoir. This was the missing link between Geosciences and reservoir engineering in field development before mid-1980s. Since then reservoir characterization has shown significant values in identifying both prolific and marginal fields, extending the production life of existing fields and increasing the hydrocarbon recovery from reservoirs. Successful reservoir characterization projects typically show high degree of integration.

Using an integrated approach helps in identifying the flow units of the reservoir and mitigate the uncertainties as much as possible to be able to ensure the recovery of an economical viable producible hydrocarbon.

Since uncertainty exist in GIIP, accurate measures are implemented to access and mitigate these uncertainties to be able to maximally recover hydrocarbon while minimizing cost using statistical approach.

This study integrates seismic data, well data, geological data, formation evaluation data and pressure volume temperature (PVT) data in resolving and managing reservoir uncertainties to estimate the hydrocarbon potential of candidate reservoirs in the UTU field onshore Niger Delta area of Nigeria.

1.2 PROBLEM STATEMENT

The UTU field is a green field located in the onshore area of Niger Delta area of Nigeria. It was discovered in 1971 by UTU 01 exploration well. There are three other wells namely UTU 002, UTU 003 and UTU 004 that penetrated the shallow reservoirs.

The A, B, C, D and E reservoirs are the deeper appraisal target with likelihood of been gas bearing. The field is faced with data limitation due to 3D seismic data quality and resolution and one well penetration resulting in high level of uncertainty in structure, lateral sand development, reservoir properties and fluid contacts. Hence, the need to accurately identify, quantify and manage these inherent uncertainties for optimal reservoir development.

This study is focused on using an integrated approached across relvant disciplines to identify, quantify and manage these uncertainties to safely and efficiently recover producible hydrocarbon economically.

1.3 PROJECT AIMS AND OBJECTIVES

The primary objective of this study is to evaluate and appraise the hydrocarbon potential of A, B, C, D and E reservoirs in the UTU field and propose an economically viable development strategy for them.

The key objectives of this study are categorized as follows;

1.3.1 BUSINESS OBJECTIVES

- To access the hydrocarbon potential in five (5) unapprised reservoirs (A, B, C, D, and E)
- To increase Shell reserve resource rate and add value to shell bottom line
- To provide an upside to the existing volumes in the field
- Provide an economically viable development strategy

TECHNICAL OBJECTIVES

- Develop a structural framework for input to the static model for A, B, C, D and E reservoirs
- Reservoir property prediction from seismic inversion for input to the static model
- Fluid contact estimation for GRV calculation

1.4 SCOPE OF WORK AND DELIVERABLES

Reservoir characterization generally involves an integrated approach from different disciplines. For this project, the specific scope and objectives includes;

- Gather and review all available data (well data and seismic data)
- Identify and manage key uncertainties
- Carry out detailed structural interpretation
- Build structural framework
- Execute reservoir properties prediction for A, B, C, D and E reservoirs
- Conduct fluid contact estimation for the A, B, C, D and E reservoirs for GRV calculations
- Carry out quick look economics and identify possible optimal development strategy for A, B, C, D and E reservoirs

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1.5 SIGNIFICANCE OF STUDY

- The result of this study will increase SPDC reserve recourse rate and provide an upside to the existing volumes in the field if found hydrocarbon bearing and economically viable.
- Enable M. Sc research interns to gain relevant practical and industry experience in partial

  Fulfilment for the award of an M.Sc Geophysics degree
- Create an enabling environment for the M. Sc research interns to gain technical competence in the use of industry software and improve inter-personal relationship skills

1.6 LIMITATIONS OF STUDY

- Poor 3D seismic data quality and resolution in the reservoirs of interest
- One well penetration in the reservoirs (A, B, C, D and E) of interest
- Incomplete suite of logs

  - **3D Seismic Data:** The seismic data used was a merge of different surveys which was acquired differently but the seismic which covered the area of interest was shot in 1991 with a 3km cable in the inline direction. This can be improved with a modern wide azimuth seismic data acquisition this will mitigate the degree of uncertainties in the plays and prospect identification.
  - **One Well Penetration:** One well penetrated the reservoirs of interest thereby creating a high level of uncertainty away from the well. This was mitigated by building velocity models and using a generic method to estimate depth uncertainties for top structure low and high cases.
  - **Incomplete suite of logs:** Incomplete suite of logs arising from one well control. This can be mitigated from acquisition of more logs when new wells are drilled.

    This was mitigated using reservoir properties derivation using inversion method.

1.7 METHODOLOGY SUMMARY

A multi-disciplinary integration approach was adopted to develop a representative model of the subsurface. The subsurface roles are as follows: Production Seismologist (PS), Reservoir Geophysicist (RG), Quantitative Interpretation (QI), Production Geologist, Petrophysics (PP), Reservoir Engineering (RE), Production Technologist (PT) which were undertaken by a Geophysicist, Geologist and Petroleum Engineer respectively in an integrative and iterative way. The integration approach used for this study is shown in the integrated workflow below;

PROJECT INTEGRATED WORKFLOW

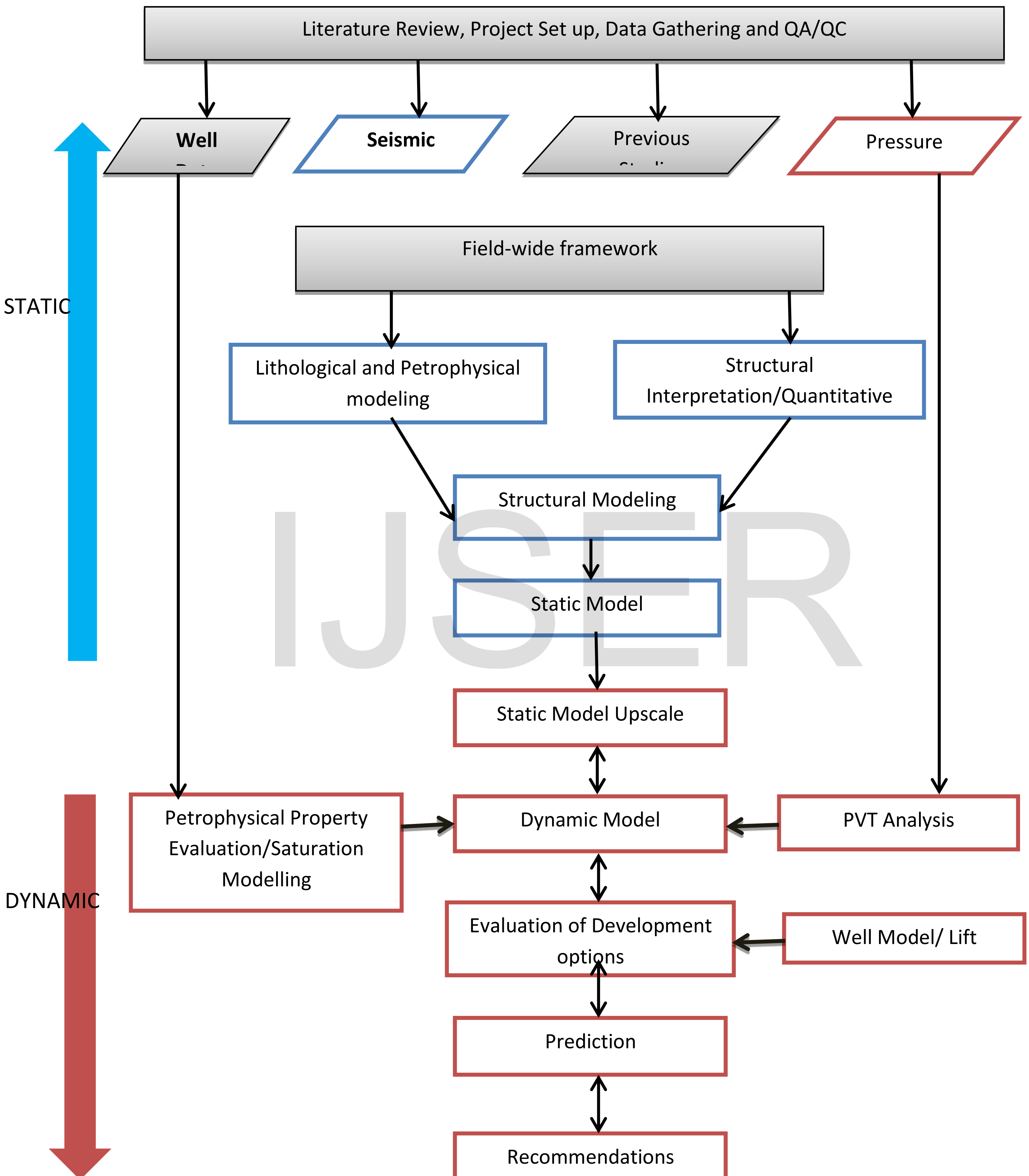

Figure 1. Integrated team workflow

CHAPTER TWO

LITERATURE REVIEW

2. 1 INTRODUCTION

The goal of the E & P Company is to explore and produce profitable hydrocarbon resources in a safe and environmental friendly way. However, this cannot be achieved independently. It involves a multi-disciplinary approach which includes Geophysics, Geology, Reservoir Engineering and Petro-Physics e.tc.

Reservoir performance prediction and characterization are important tools to provide a reliable reservoir model for flow simulation, assess recovery rate, performance and eventually minimize cost and improve Hydrocarbon productivity. This depends on various petrophysical quantities which have uncertainties despite the inter-disciplinary integration due to the complex nature of the sub-surface. Hence, these uncertainties must be accessed and mitigated for proper economically viable field development.

The reliability of the result depends on the data availability, the degree of uncertainty, available technology and the mitigation measures employed. Results have shown that successful reservoir characterization shows high level of integration across disciplines. Reservoir uncertainties can be reduced with better reservoir characterization by integrating available data and building static and dynamic models.

The purpose of this study is to build a reliable and consistent model with the available data that can access the hydrocarbon potential, offer an accurate future production predictions and provide better economic analysis with limited uncertainties.

2.2 NIGER DELTA GEOLOGY

The Niger Delta is situated in the Gulf of Guinea and lies between Latitude 3˚ and 6̊ N and Longitude 5̊ and 8̊ E respectively. Known oil and gas resource of the Niger Delta ranked the province as the twelfth most prolific petroleum producing tertiary Deltas and one of the most economically prominent sedimentary basin in African continent.

The Niger Delta province has only one identified Petroleum Systems (Ekweozor and Daukoru 1994). The system is referred to as the Tertiary Niger Delta (Akata-Agbada fm) petroleum system. The maximum extent of the petroleum system corresponds to the province boundary while the minimum extent of the system is defined by the areal extent of the field and known resources of 34.5billion barrel of Oil and 93.8 trillion cubic feet of gas (Petroconsult, 1996a). Presently, majority of the petroleum fields are located onshore or in the continental shelf between 100-200 meters deep. Among the provinces ranked in the U.S. Geological Survey's World Energy Assessment (Klett and others, 1997), the Niger Delta province is the twelfth richest in petroleum resources, with 2.2% of the world's discovered oil and 1.4% of the world's discovered gas (Petroconsultants, Inc. 1996a).

The Niger Delta formed along a failed arm of a triple junction related to the opening of the South Atlantic starting in the Late Jurassic and continuing into the Cretaceous (Burke et al., 1972; Whiteman, 1982). The two arms followed the Southwestern coast of Nigeria and Cameroon developed into the passive margin of west Africa while a third failed arm formed the Benue Trough. 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 possible contribution from interbedded marine shale of the lowermost Agbada Formation. Oil is produced from sandstone facies within the Agbada Formation, however, turbidite sand in the upper Akata Formation is a potential target in deep water offshore and possibly beneath currently producing intervals onshore.

The coastal sedimentary basin of Nigeria has been the scene of three depositional cycles. The first began with a marine incursion in the middle Cretaceous and was terminated by a mild folding phase in Santonian time. The second included the growth of a proto-Niger delta during the Late Cretaceous and ended in a major Paleocene marine transgression. The third cycle, from Eocene to Recent, marked the continuous growth of the main Niger Delta. A new threefold lithostratigraphic subdivision is introduced for the Niger delta subsurface, comprising an upper sandy Benin Formation, an intervening unit of alternating sandstone and shale named the Agbada Formation, and a lower shaly Akata Formation. These three units extend across the whole delta and each range in age from early tertiary to recent. They are related to the present outcrops and environments of deposition. A separate member of the Benin Formation is recognized in the Port Harcourt area. This is the Afam Clay Member, which is interpreted to be an ancient valley fill formed in Miocene sediments. Subsurface structures are described as resulting from movement under the influence of gravity and their distribution is related to growth stages of the delta. Rollover anticlines in front of growth faults form the main objectives of oil exploration, the hydrocarbons being found in sandstone reservoirs of the Agbada Formation.

2.2.1 TECTONICS

The tectonics framework of the continental margin along the West Coast of equatorial Africa is controlled by Cretaceous fracture zones expressed as trenches and ridges in the deep Atlantic. The fracture zone ridges subdivide the margin into individual basins and form boundary faults of the cretaceous Benue-Abakaliki trough which cuts far into the West African shield. The trough represents a failed arm of a rift triple junction associated with the opening of the South Atlantic. In this region, rifting started in the Late Jurassic and persisted into the Middle Cretaceous (Lehner and De Ruiter, 1977). In the region of the Niger Delta, rifting diminished altogether in the Late Cretaceous.

After rifting ceased, gravity tectonism became the primary deformational process. Shale mobility induced internal deformation and occurred in response to two processes (Kulke, 1995). First, shale diapirs formed from loading of poorly compacted, over-pressured, prodelta and delta-slope clays (Akata Fm.) by the higher density delta-front sands (Agbada Fm.). Second, slope instability occurred due to a lack of lateral, basin ward, support for the under-compacted delta-slope clays (Akata Fm.) For any given Depobelt, gravity tectonics were completed before deposition of the Benin Formation and are expressed in complex structures, including shale diapirs, roll-over anticlines, collapsed growth fault crests, back-to-back features, and steeply dipping, closely spaced flank faults. These faults mostly offset different parts of the Agbada Formation and flatten into detachment planes near the top of the Akata Formation.

2.2.2 AKATA FORMATION

The Akata formation is the primary source rock of the Niger Delta. The most prolific petroleum system in Africa located in the Tertiary Niger Delta. It is beneath the current producing intervals deep water offshore.

In petroleum Geology, source rocks refer to rocks which are capable of generating hydrocarbon. They form the elements of a hydrocarbon system. They are rick in organic material / sediments that have been deposited in a variety of environment ranging from marine, lacustrine to deltaic. This consists of 50% marine shale facies. Stacher (1995) proposed that the Akata Formation is the only source rock with significant volume with burial depth consistent with the depth of the oil window.

2.2.3 AGBADA FORMATION

The Agada formation are the major source rocks of the Niger Delta and contains an interval of Organic rich carbon content (Ekweozor and Okoye, 1980; Nwachukwu and Chukwura, 1986). It is the hydrocarbon prospective sequence, a paralic clastic sequence which is directly overlying the Akata formation and underlying the Benin formation.

The Agbada formation consists predominantly sandy units with minor shale intercalations and thick shale units at the base (alternation of paralic sands, shale and clay). This sequence is over 4,000m thick but thicker at the central part showing that the depocenter is in the Central Niger Delta (Evamy et al. 1978). The alternation of fine and coarse clastic sediments or clastic particles provides multiple reservoirs-seal couplets, the paralic sequence is present in all Depobelt, and the age ranges from Eocene to Pleistocene.

2.2.4 BENIN FORMATION

This is the youngest formation of the Niger Delta which is overlying the Agbada formation. It is approximately 280 meters thick. It consists mostly of continental sands with gravels. It prograde southward to westward from Eocene to present forming Depobelt that represents active part of the Delta at each stage of its development (Doust and Omatsola, 1990). The age of the formation is between Oligocene to the present non-marine sands deposits in the alluvial or upper coastal plain environment during the progradation of the Niger Delta. This formation thins basin ward and ends near the edge of the shelf. Depobelt showing the Agbada, Akata and Benin formations is shown below;

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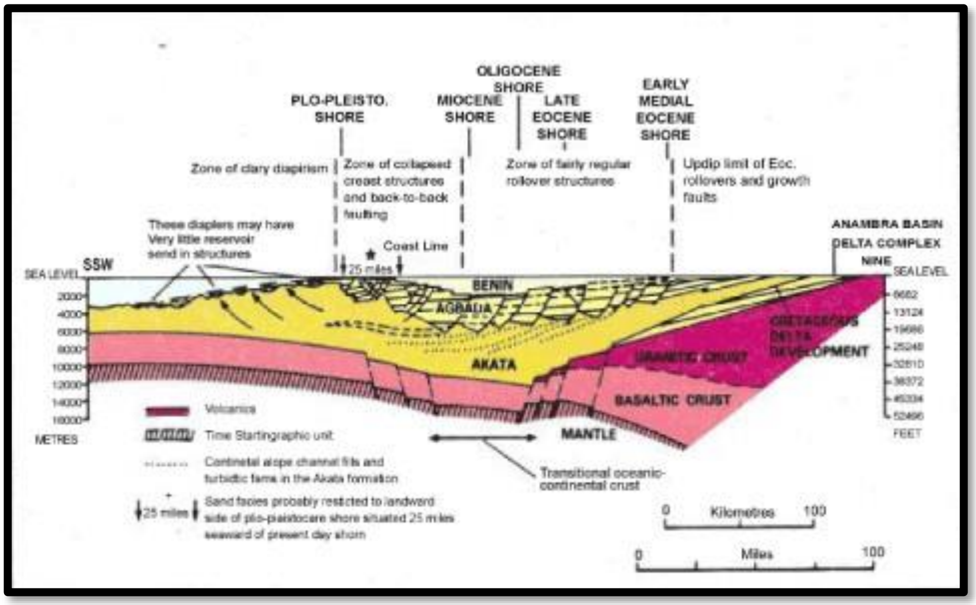

Figure 2.3. Niger Delta formations

2.2.5 DEPOBELT

Deposition of the three formations occurred in each of the five offlap siliciclastic sedimentation cycles that comprise the Niger Delta**.** These cycles (depobelt) are 30-60 kilometers wide, prograde southwestward 250 kilometers over oceanic crust into the Gulf of Guinea (Stacher, 1995), and are defined by syndepositional faulting that occurred in response to variable rates of subsidence and sediment supply (Doust and Omatsola, 1990). The interplay of subsidence and supply rates resulted in deposition of discrete depobelts when further crustal subsidence of the basin could no longer be accommodated, the focus of sediment deposition shifted seaward, forming a new depobelt (Doust and Omatsola, 1990). Each depobelt is a separate unit that corresponds to a break in regional dip of the delta and is bounded landward by growth faults and seaward by large counter-regional faults (Evamy and others, 1978; Doust and Omatsola, 1990). Five major depobelts are generally recognized, each with its own sedimentation, deformation, and petroleum history.

Doust and Omatsola (1990) describe three depobelt provinces based on structure. The northern delta province, which overlies relatively shallow basement, has the oldest growth faults that are generally rotational, evenly spaced, and increase their steepness seaward. The central delta province has depobelts with well-defined structures such as successively deeper rollover crests that shift seaward for any given growth fault. Last, the distal delta province is the most structurally complex due to internal gravity tectonics on the modern continental slope. The Niger Delta depobelt is shown diagrammatically below;

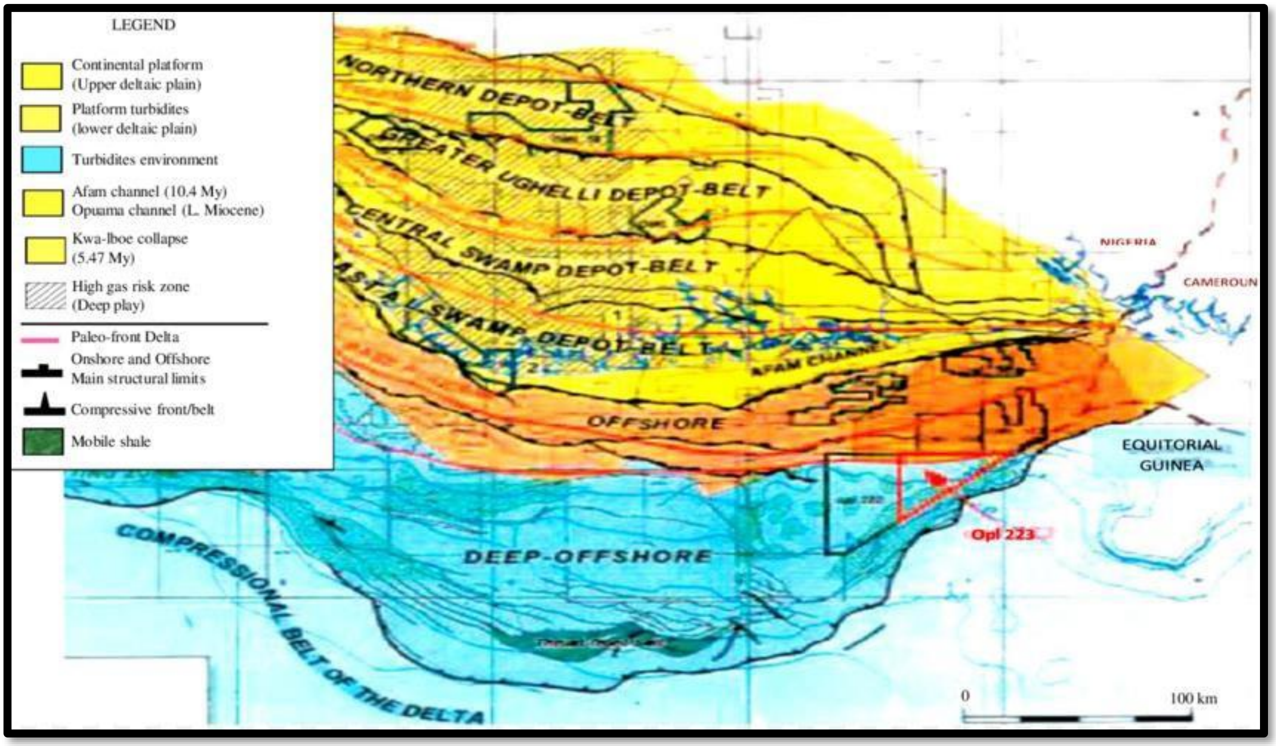

Figure 2.1. Location of the study area in the Niger Delta depo belt

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2.2.6 NIGER DELTA STRUCTURAL STYLE

The Niger Delta structural style is predominantly growth fault system are syndepositional evolving from margins of continental plates. These syndepositional faults are bounded by major bounding faults and vary in complexity from the proximal to the distal end. The structural complexity is identified as a depobelt with a unique structural style typified with some peculiar faulting style and gets younger form the proximal to the distal with the oldest located at the continental.

There are five major depobelts in the Niger Delta basin each having a unique trapping style namely; Northern Delta, Greater Ugheli, Central swamp, Coastal swamp and Offshore. Hence, the Northern Delta is the oldest while Offshore Niger is the youngest Niger Delta depobelt.

However, the central swamp is characterized by synthetic and antithetic faults bounded by major bounding faults. collapsed crest are also present in this depobelt. The field location is characterized by series of synthetic down to basin listric growth faults dipping basin ward. Series of counter regional and antithetic faults exists few kilometers away from the UTU field with evidence of back to back and collapsed crest structures. The trapping mechanism is predominantly rollover anticline with four way deep closures. The structural style is shown diagrammatically below;

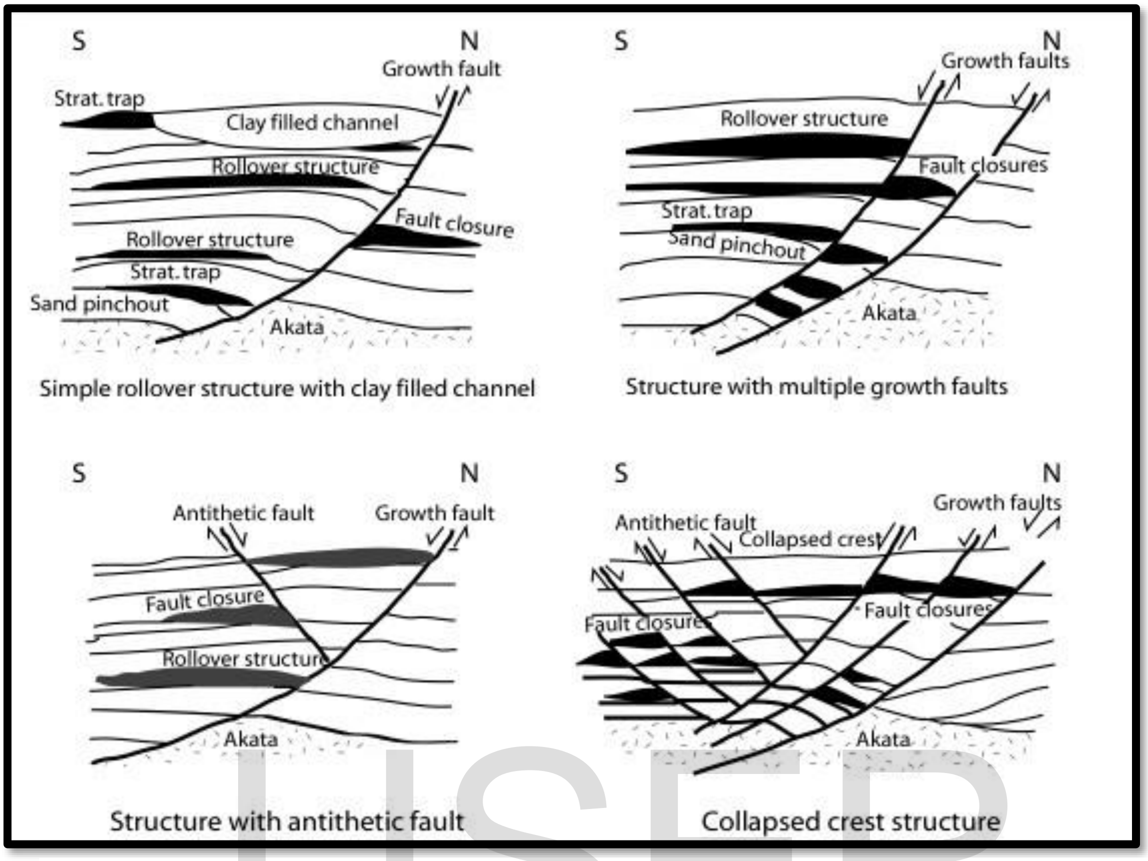

Figure 2.3. Geologic section of Niger Delta structural styles (Doust and Omatsola, 1990)

2.2.7 TRAPS AND SEALS

Most known traps in Niger Delta fields are structural although stratigraphic traps are not uncommon. The structural traps developed during syndepositional deformation of the Agbada paralic sequence (Evamy and others, 1978; Stacher, 1995). The structural complexity increases from the north to the south in response to increasing instability of the under-compacted, over- pressured shale. Doust and Omatsola (1990) describe a variety of structural trapping elements, including those associated with simple rollover structures, clay filled channels, structures with multiple growth faults, structures with antithetic faults, and collapsed crest structures.

On the flanks of the delta, stratigraphic traps are likely as important as structural traps (Beka and Oti, 1995). In this region, pockets of sandstone occur between diapiric structures. Towards the delta toe (base of distal slope), this alternating sequence of sandstone and shale gradually grades to essentially sandstone.

The primary seal rock in the Niger Delta is the interbedded shale within the Agbada Formation. The shale provides three types of seals—clay smears along faults, interbedded sealing units against which reservoir sands are juxtaposed due to faulting, and vertical seals (Doust and Omatsola, 1990). On the flanks of the delta, major erosional events of early to middle Miocene age formed canyons that are now clay-filled. These clays form the top seals for some important offshore fields (Doust and Omatsola, 1990).

2.2.8 PETROLEUM GENERATION AND MIGRATION

The present day Niger Delta Oil window is estimated to be within 240̊F (115̊ C) according to Evamy and others (1978). In the northwestern portion of the delta, the oil window lies in the upper Akata Formation and the lower Agbada Formation. To the southeast, the top of the oil window is stratigraphically lower (up to 4000′ below the upper Akata/lower Agbada sequence; Evamy and others, 1978). Top of the oil window is attributed to the distribution of the thickness of the thickness and sand/shale ratio between overburden rock (Nwachukwu and Chukwura, 1986; Doust and Omatsola, 1990; Stacher, 1995). The sandy continental sediment (Benin Fm.) has the lowest thermal gradient (1.3 to 1/8°C/100 m); the paralic Agbada Formation has an intermediate gradient (2.7°C/100 m); and the marine, over-pressured Akata Formation has the highest (5.5°C/100 m) (Ejedawe and others, 1984). Therefore, within any depobelt, the depth to any temperature is dependent on the gross distribution of sand and shale. If sand/shale ratios were the only variable, the distal offshore subsurface temperatures would be elevated because sand percentages are lower. To the contrary, the depth of the hydrocarbon kitchen is expected to be deeper than in the delta proper, because the depth of oil generation is a combination of factors (temperature, time, and deformation related to tectonic effects) (Beka and Oti, 1995).

In the late Eocene, the Akata/Agbada formational boundary in the vicinity of this well entered the oil window at approximately 0.6 R_O (Stacher, 1995). Evamy and other (1978) argue that generation and migration processes occurred sequentially in each depobelt and only after the entire belt was structurally deformed, implying that deformation in the Northern Belt would have been completed in the Late Eocene. The Akata/Agbada formational boundary in this region is currently at a depth of about 4,300 m, with the upper Akata Formation in the wet gas/condensation generating zone (vitrinite reflectance value >1.2; Tissot and Welte, 1984). The lowermost part of the Agbada Formation here entered the oil window sometime in the Late Oligocene.

Migration from mature, over-pressured shales in the more distal portion of the delta may be similar to that described from over-pressured shales in the Gulf of Mexico. Hunt (1990) relates episodic expulsion of petroleum from abnormally pressured, mature source rocks to fracturing and resealing of the top seal of the over-pressured interval. In rapidly sinking basins, such as the Gulf of Mexico, the fracturing/resealing cycle occurs in intervals of thousands of years. This type of cyclic expulsion is certainly plausible in the Niger Delta basin where the Akata Formation is over- pressured. Beta and Oti (1995) predict a bias towards lighter hydrocarbons (gas and condensate) from the over-pressured shale as a result of down-slope dilution of organic matter as well as differentiation associated with expulsion from over-pressured sources. The burial history chart s shown below;

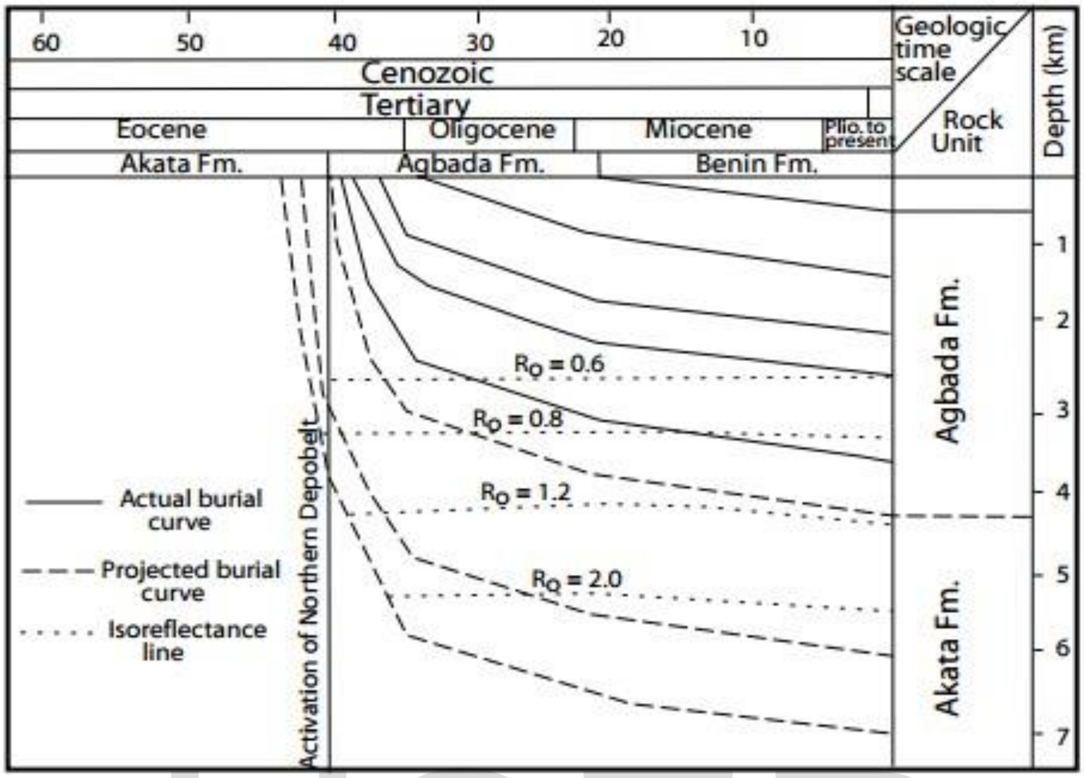

Figure 2.4. Burial history chart of the Niger Delta Petroleum System. Data from Oben-1 well in Northern Depobelt. Tuttle et al., 1999, Ekweozor and Daukoru, 1994)

2.3 RESERVOIR MODELING

Reservoir modeling is the process of generating numerical representations of reservoir conditions and properties using geological, geophysical and engineering data measured on the earth surface or in depth with limited number of well penetration. Subsurface reservoir modeling is a fundamental practice in many geoscience disciplines; hydrology, ground water analysis, geothermal studies and exploration and recovery of hydrocarbon resources. During exploration, appraisal, development and production stages of any hydrocarbon field cycle, reservoir models are widely used to broaden the available knowledge of the geophysical, geological and engineering aspect of the reservoir.

Hence, Reservoir modeling is a critical and challenging aspect of field development process. It is important to build an accurate and efficient modeling of complex reservoir geometry and heterogeneous reservoir properties.

An integrated reservoir modeling and optimization is significant in the petroleum industry field development process and continuous asset management evaluation. The interdependence between reservoir, surface pipeline network, process facilities and economic analyses are observed simultaneously. The integrated field model helps to determine some specific problems that are undetectable using stand-alone model simulation. A reservoir model is built using all available data to build an accurate reservoir model that is fit for purpose to the field development. A good model is an essential element for increasing the production life and extending the field development life. There are two basic type of reservoir modeling namely static (time independent geological properties) and dynamic reservoir modeling.

2.4 REASONS FOR BUILDING A RESERVOIR MODEL

The most common use of reservoir models is to provide a 3D numeric input to reservoir simulation. Reservoir modeling and simulation provides the basis for maximizing economic value for field development and operational decisions. The typical motivation for reservoir simulation is to increase profitability through better reservoir management. These includes development plans for new fields and depletion strategies for mature fields. Reservoir modeling and simulation can address oil, water and gas volume forecasting, decline analysis, infill drilling uplift, secondary or tertiary recovery options, well management strategies, water/gas handling strategies and facility constraints, contact movement, liquid dropout, reservoir surveillance strategies, injection strategies, and well and completion designs. Reservoir modeling and simulation can also be used for reserve estimation, equity determination, or support for funding large projects. Traditional mapping and cross-section methods worked relatively well for homogeneous reservoirs, but they tend to overestimate sweep efficiency for heterogeneous reservoirs. These methods may significantly under- or over-estimate in-place hydrocarbon resources because they lack 3D examination of reservoir heterogeneities. Reservoir modeling and simulation provide powerful tools for more accurate reservoir description and hydrocarbon production forecasting (Dubrule, 1989; Yu et al., 2011), and can help in reservoir management and field development. Accurate reserve assessment through reservoir modeling and simulation could help reduce cost and increase recovery rate.

Reservoir modeling is critical to rapid successful commercialization of discovered and undeveloped hydrocarbon resources, as well as optimizing depletion of mature fields. As a rapidly growing discipline, reservoir modeling has become an integral part of the field asset management. For large and capital-intensive development projects, reservoir modeling and simulation have almost become a necessity. Even for small to medium reservoirs, modeling and simulation can enhance efficient development, and depletion planning, and potentially increase reserves and yield cost saving. Modeling can also help in moving static resources to reserves.

Reservoir modeling is a critical link between seismic interpretation and reservoir simulation. Without reservoir modeling, integrated approaches to E&P solution and accurate reservoir evaluation are almost impossible. Building a reservoir model used to be very costly, but availability of increasingly versatile and sophisticated software packages has made reservoir modeling much more efficient and affordable.

2.5 UNCERTAINTIES

The subsurface complexity and limited data make the reservoir characterization and modeling complex which explains the large uncertainty space in managing a hydrocarbon resource project (Massonnate, 1997).

Quantification of uncertainty should be considered as much as possible uncertainty factors to approach the total uncertainty space. Uncertainty of each factor also should be correctly represented by a statistical distribution. When data that correlate with the target variable are introduced into the modeling, the uncertainty space can be narrowed. If the uncertainties in the input factors are reduced, the uncertainty space will be narrowed. Hence, Identification and quantification of uncertainties is the first step towards mitigation and management of reservoir uncertainties and key reservoir parameters that affect in-place volumes and recovery rate (Itotoi et al., 2010) both in the static and dynamic domains. However, variation of uncertainties from project to project is dependent on the availability of data and the complexity of the reservoir at the exploration and appraisal stage (Itotoi et al, 2010). Uncertainties are classified into the following;

- **Inference Uncertainty:** These are uncertainties which are introduced into a reservoir characterization and modelling process due to the assumptions made because of data limitations, data quality and data interpretation.
- **Predictive Uncertainty:** These are associated structural, lithofacies, and rock properties

  predictions. Increase in complexity of the Geology and reservoir architecture decreases the rate of properties predictions (Shepherd, 2009).

- **Measurement Uncertainty:** Uncertainty in data is mainly caused by uncertainties in measurements (e.g. seismic acquisition geometry, and log data sampling rates) and secondarily by post-acquisition handling e.g. processing algorithms, log normalization,

  depth shifting, reliability quotient of bio-data.

Uncertainty is ubiquitous in reservoir characterization, and it exists in various disciplines, including;

- Seismic data acquisition and processing
- Fault and horizon interpretation
- Time to depth conversion
- Structural modeling
- Petrophysical analysis
- Geological interpretation
- Fluid contacts
- Reservoir properties distribution

2.5.1 GEOPHYSICAL UNCERTAINTIES

Seismic data interpretations are based on the use of seismic inlines, crosslines, random lines (Buchanan et., 1988; Dalley et al., 1989; Tucker et al., 1983). Full utilization of all information contained in seismic data is today's challenge. Interpreters needs to combine knowledge within geology and geophysics disciplines. Lack of sound geological understanding leads the geophysicist to interpret unrealistic and inaccurate results. The impact of the uncertainties inherent in the inputs of the geophysicist into the integrated reservoir model is discussed in greater detail below.

2.5.2 SEISMIC DATA ACQUISITION UNCERTAINTIES

Abernethy et al., (2009) discovered that uncertainty related to seismic acquisition is very much dependent on the quality of data acquired in the offshore or onshore environment. Although in marine acquisition "feathering" of acquisition streamers due to ocean currents may pose a certain risk, pre-processing and proper QC can mitigate data quality and minimize associated uncertainties. However, in land data acquisition uncertainties are much larger and are very much dependent on both geographical location and geological terrain. Here resulting uncertainties can be significant especially in foothills settings or in near coastal areas due lack of proper acoustic coupling/ propagation, ground noise and missing traces. These will impact the subsequent processing sequence and ultimately the seismic image.

2.5.3 SEISMIC DATA PROCESSING UNCERTAINTIES

Substandard seismic data pre-processing may obliterate the final seismic image. Incorrect statics will impact the shape, position and continuity of reflectors. Inadequate reflection strength will lead to inaccurate rock property analysis. Stacking is an important phase of seismic data processing because the image is constructed at the stage. Use of incorrect velocity will result to reduction of the overall energy of the stacked data. Abrahamsen (1993) was the first to use geostatistical condition simulation techniques to generate multiple realizations of imaged surfaces in depth; Vincent et al. (1999) addressed the question of optimal well placement given the uncertainty on imaged structures. Thore et al. (2002) presented the sources of uncertainty in seismic processing in details along with a methodology for generating realizations of structures and a procedure for optimal well placement of future wells.

Migration is the process of collapsing diffraction and moving events to their actual subsurface position Abernethy et al., (2009). Its impact, in terms of structural image is crucial (at least, when dips are not negligible) and it recovers much of the lateral resolution of the seismic data (for all dips). Migration moves reflectors in their true position and collapses diffractions. Therefore, the impact in terms of the structural image is crucial especially if reflectors are dipping. Migration uncertainty depends on the accuracy of the velocity and on the migration algorithms (Singh et al., 2009). The uncertainty associated with the velocity should be determined prior to migration.

As in the case of acquisition, sources of uncertainty will need to be incorporated through image interpretation and accounted for in the final structural framework.

2.5.4 SEISMIC DATA INTERPRETATION UNCERTAINTIES

Seismic data interpretation is a processing of interpreting the events to generate the reservoirs geometry and architecture. To achieve this, a combination of different available information such as seismic data and information from wells. The reservoir extent and geometry are defined from this process. The uncertainty related to this process is properly identified and addressed. The velocity model is used to convert the time structure maps to depth maps.

O'Dell and Lamer (2005), in a study in a green field, identified some subsurface uncertainties as: Gross Rock Volume (GRV) and Hydrocarbon-Water contacts, saturation, reservoir architecture, faults and fractures (compartmentalization), reservoir properties, pressure/volume/temperature (PVT), relative permeability, compaction, compressibility etc.

Suzuki and Caers (2006) considered structural scenario uncertainties in addition to horizons and faults position uncertainties. History matching is performed by stochastic search methods (Suzuki and Caers, 2006), by searching efficiently for reservoir models that matches historical production data considering "similarity measure" between likely structural model realizations. Structural framework definition can become very complex because of poor seismic resolution and fault shadows. Faults are inferred by diffractions and spatially aligned discontinuities of different horizons on several sections. This is often a time-consuming task as the quality of the seismic often deteriorates in the vicinity of the fault. Fault uncertainty is peculiar because it is broadly horizontal, whereas the main direction of uncertainty of horizons is vertical. When picking faults, it is important to determine those seen in the seismic data and those belonging to a conceptual geological model. Some of the uncertainties related to seismic interpretation are discussed below:

1. Structural Modelling Uncertainty: The structural model consists faults and stacks of horizons tied to well tops. Velocity modeling errors, incorrect fault interpretation are sources of structural model uncertainty. Other uncertainty sources are interpretation when building the structural framework: tying seismic markers and well synthetic seismograms, picking horizons and their continuity, fault detection, velocity model building and depth conversion of the time interpretations. Interpreter's bias based on prior knowledge on geological setting of the area, experience and interpretation concepts. (Shell IRM Team, 2009). Structural uncertainty also results from the depth conversion calculation. This uncertainty will increase with distance from the well control. As the top reservoir surface defines the upper envelope for the reservoir, the gross rock volume (GRV) between the top of the reservoir and the fluid contacts. The combination of structural uncertainty with fluid contact uncertainty (GRV estimate) typically provides the largest uncertainty of the input parameters used for volumetric evaluation (Shepherd, 2009).

2. Reservoir Area Uncertainty*:* This arises from predicting reservoir continuity away from the well location due to sparse direct sampling and seismic data resolution. For structurally-trapped accumulations, uncertainty in reservoir area is controlled by mapping of the structural trapping components e.g. fluid contact elevation, fault position and spill points.

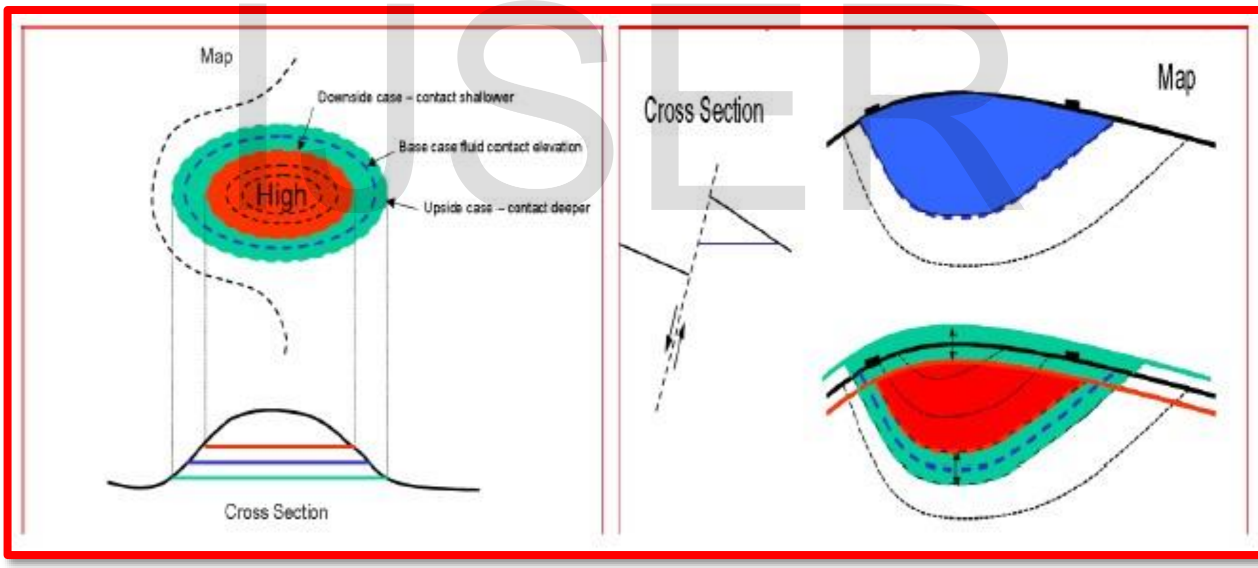

Figure 2.5. Left four (4) way dip closure with area controlled by top depth and contact elevation and Right Three (3) way dip closure with area controlled by contact elevation and fault position

3. Fluid Distribution and Contact Uncertainty

Density, reservoir compartmentalization and difference in source rock charging control the vertical and lateral distribution of fluid type in a reservoir. The contact occurs where there contrast in amplitude versus depth plots due to density contrast and buoyancy effect e.g GWC, OWC. Fluid contact uncertainty can be as a result of non- penetration of the contacts by the drilled wells, lack of differentiation between fluids on available logs, unavailability of pressure data, compartmentalization of reservoirs leading to differences in contacts at different fault blocks. Fluid distribution can be determined from the following data: logs, formation pressure tests, downhole fluid sampling, core sample UV light fluorescence, Mud logs (gas detections, cuttings shows), Seismic DHIs etc. Unavailability of these or their ambiguity can lead to uncertainties in fluid distribution.

2.6 NEED TO QUANTIFY UNCERTAINTY

In the petroleum industry, quantities such as original hydrocarbon in place, reserves, and the time for the recovery process are all critical in the economical aspect. Those quantities play a key role in making important decisions. The lack of available data in the appraisal stage of a field, or incomplete reservoir description even during the development stage, increases the risks associated with investment decisions. Quantification of these uncertainties and evaluation of the risks would improve decision making (Salomão and Grell, 201). However, estimating these uncertainties is complicated because it requires an understanding of both the reservoir's static structure and dynamic behavior during production. Even a producing field can result in a financial loss, and even mature fields have uncertainties in the reservoir description (Capen, 1975).

2.7 ACCESSING UNCERTAINTIES

Azeke et al (2009) proposed a systematic approach to evaluating uncertainties for a field development decision process. In this, the parameters are initially varied individually (one parameter at a time) to rank the key uncertainties and then an experimental design is used to estimate the impact of uncertainty in the parameters with the largest impact on the project. Firstly, a range of static and dynamic models (low, mid and high cases) are built and different development schemes tested on each model and the scheme with the optimum recovery was taken forward for further uncertainty analysis prior to field development. A probabilistic method, Gaussian approximation was used in estimating the degree of uncertainty around the base case value of a parameter. A tornado chart was used in ranking the effect of these parameters as a screening tool to identify the major parameters influencing the hydrocarbon in place.
O'Dell et al (2005) adopted a two-phase approach: sensitivity analysis and scenario modelling. In the sensitivity analysis phase, uncertainties that would have the greatest impact on volumes are identified and ranked. The key impact parameters were then analyzed using the Monte Carlo technique. In the scenario-modelling phase, several subsurface realizations were generated to capture the full range of possibilities and optimize development. The realizations were notionally organized from high-high to medium-medium to low-low.
Stochastic models offer the possibility to quantify the uncertainty related to the geological description. Infinite possible realizations of the random function can be obtained just by varying the generator seed and the comparison of' a sufficiently large number of geological images will provide a measure of the uncertainty associated with the assumed geological model. One of the most interesting applications of uncertainty quantification concerns the computation of the oil in place. The combination of several realizations of the various geological parameters provides a useful insight into the uncertainty existing in the oil in place figure. Unlike the deterministic approach of O' Dell et al (2005), Itotoi et al (2010) proposed a stochastic approach to uncertainty analysis, to adequately capture and manage uncertainties. In applying this stochastic approach to cases where the base parameters have widely varying ranges of uncertainties, the proposed use of statistics since all the possible realizations would require many runs. Hence, the adopted the Experimental Design approach, whereby he identified both static and dynamic uncertainties, performed Monte Carlo simulations using probability distribution and generated probability density functions (PDF) for uncertainty levels. A measure of the uncertainty related to the reservoir structural model can be evaluated in a deterministic way, using alternative interpretations and velocity models, a more thorough and rigorous exploration of the uncertainty domain can be done through a stochastic approach (Abrahamsen et al.,)

In general, the potential uncertainty that exists in the structural modeling phase of a reservoir study is significant, a recent paper discusses the results of the application of probability fields to the evaluation of the structural uncertainty (Vincent et al., 1999). The oil initially in place (OOIP) computed by means of 200 realizations of the stochastic model showed a considerable dispersion of the values, with the 5th quartile (Q5) being about half of the 95th quartile (Q95).

Interestingly, similar results were obtained in the framework of the Great Reservoir Uncertainty Study, performed on a North Sea Brent reservoir by a consortium of Norwegian companies. The results of this project showed that the structural geological uncertainty, including fault description and reservoir top and base maps, accounted for three quarters of the total reserves uncertainty (Bu and Damselth, 1996)

2.8 FIELD OVERVIEW

The UTU field was discovered by the UTU exploration well in 1977 onshore Niger Delta area of Nigeria. It is in the central swamp Depobelt of the Niger Delta Basin, Nigeria. The field is a green field without any appraisal well. It is ca. 14sq.km onshore Niger Delta. It is situated in the Lyzta field with series of rollover anticlines bounded from the north to the south by major bounding faults.

The UTU filed has a total of four (4) well penetrations but only one well penetrated the A, B, C, D and E reservoirs wet. There is no production history in the reservoirs till date. The depositional environment is Channelized Shoreface of a wave dominated deltaic environment with stacks of reservoirs in the Agbada formation sand shale sequence. Structurally, the hydrocarbons are trapped in a NE-SW trending rollover anticline with synthetic and antithetic faults bounded by major faults. The reservoirs have Eastern and Western culminations separated by a saddle. Result from the study will help company determine whether to go on and drill an appraisal well to test the western flank for possible hydrocarbon accumulation. The study area is shown in the map below;

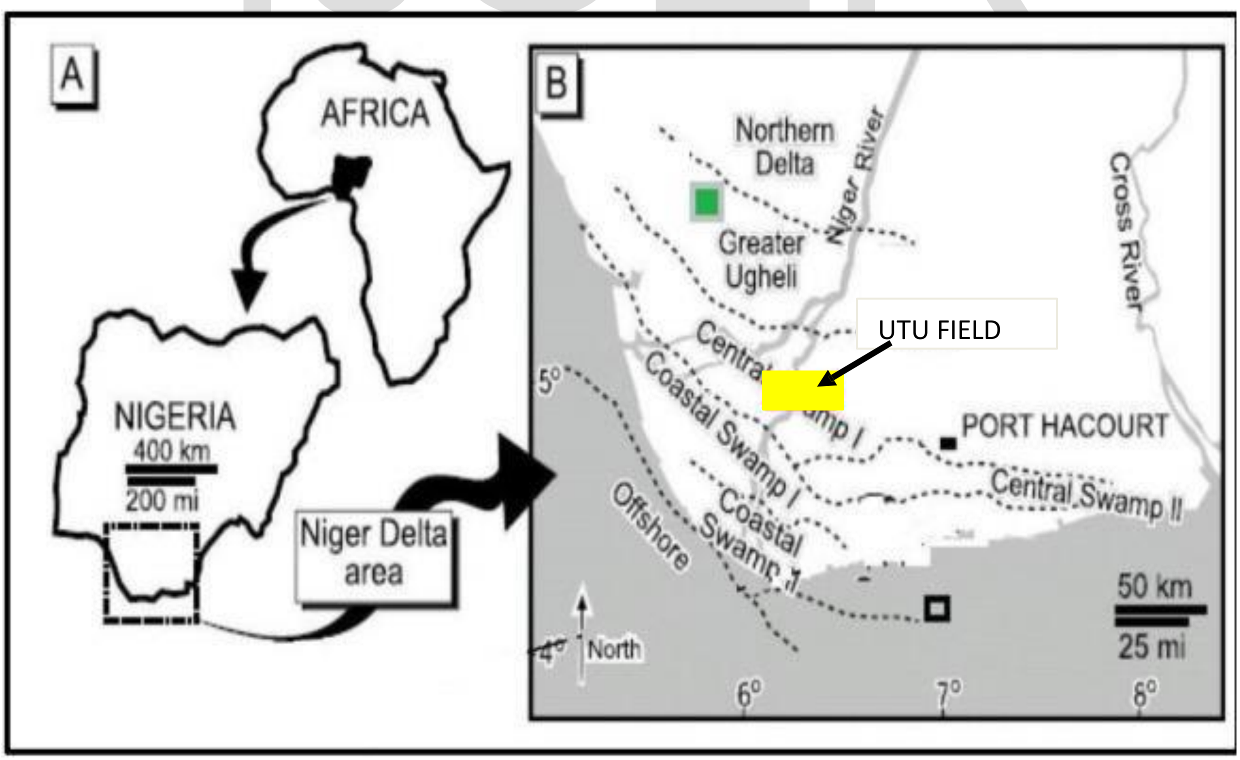

Figure 2.6. Location of the study area

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CHAPTER THREE

METHODOLOGY

3.1 Preamble:

This aspect is focused on the various methodologies adopted in carrying out this project.

This encompasses the structural interpretation and the reservoir Geophysics (QI) aspect that yielded the results that were inputted into the static and dynamic models respectively. However, this was realized using the discipline workflow below;

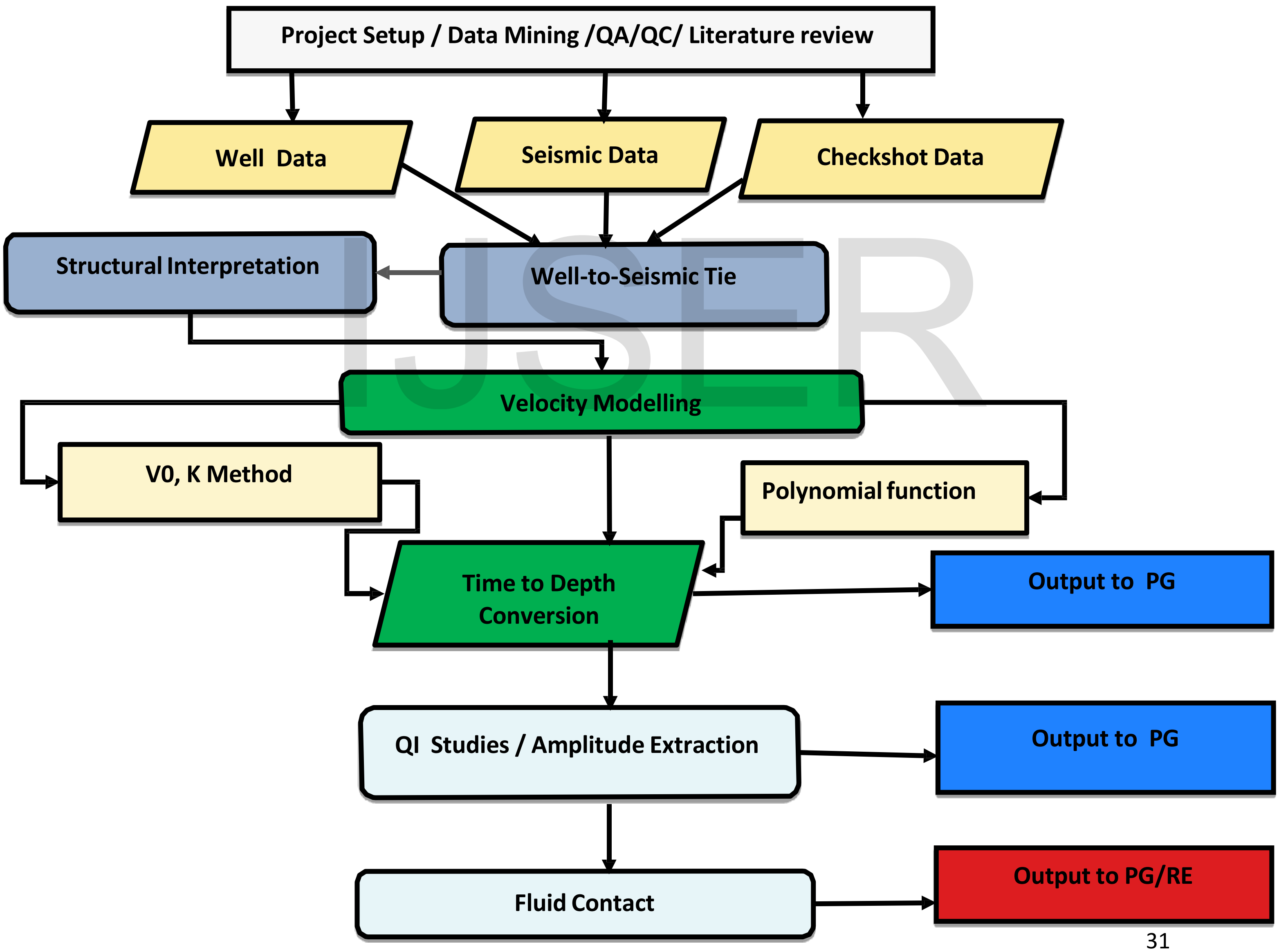

Figure 3.1. Discipline workflow

3.2 DATA AVAILABILITY

Table 3.1. Data availability

DATA	AVAILABILITY	REMARK
3D Seismic	Yes	Poor seismic quality in the area of interest
Inverted seismic volume	Yes	Good quality
Check shots	Yes	One (UTU 01) check-shot
Well tops	Yes	Available in A, B, C, D and E reservoirs
SUITE OF LOGS AVAILABILITY		
LOG	**AVAILABILITY**	**REMARK**
Gamma ray	Yes	Good quality logs
Neutron	No	Not available
Density	Yes	Good quality log
Sonic	Yes	Good quality
Resistivity	No	Not available

3.3 SEISMIC DATA ACQUISITION AND PROCESSING

A 3D seismic data was used for this project which consists of the filtered, non-filtered and an RTM volume respectively. The filtered and non-filtered volumes were a mega merge of different surveys.

The UTU field seismic was acquired in the inline direction in 1997 with a 3km cable.

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The seismic was re-processed in 2011 and 2016 respectively. However, the 2016 re-processed seismic did not fully cover the area of interest.

Hence, it is worthy to know that the different volumes were used for this project due to the complexity of project.

3.3.1 SEISMIC DATA

Different processed seismic volumes were used and they are as follows;

- Full stack filtered volume
- Full stack non-filtered volume
- Near stack
- Mid stack
- Far stack
- RTM full stack

3.3.2 WELL LOGS

The UTU field having one well penetration has the log availability listed earlier in table 3.1 above.

CHECK-SHOT

The reservoirs of interest have one check-shot data availability because of its one well penetration. This study was therefore limited to the one check-shot available.

3.4 DATA LOADING AND QUALITY CONTROL

All available data were imported and quality checked using the appropriate software. This was a way of ensuring that all available data was of good quality.

3.5 WELL LOG QUALITY CONTROL

Edited logs from QI studies were used but the caliper log was further used to QC the logs to ensure that there is no wash out zones. The logs were deemed okay for the project.

3.6 SEISMIC DATA QUALITY CONTROL

The 2011 re-processed seismic data quality was good at the shallow but deteriorates around 2ms which was generally due to fault shadow effects. The 2016 RTM seismic was of a better quality because of the modern processing algorithm that it underwent but the limitation was that it did not cover the entire prospect area. Hence, the 2011 and 2016 re-processed seismic data were used to successfully achieve the project objectives

3.7 REFLECTIVITY PATTERN ANALYSIS

The first step in seismic data interpretation is usually reflectivity pattern analysis. It is a forward modeling process which models the Density and Sonic log to understand the reflections at different lithologies. It is done before the seismic to well tie and the result guides the interpreter in achieving an accurate well tie result thereby giving rise to a more robust and accurate mapping of the correct seismic loops.

However, this is guided by the SEG and Anti-SEG conventions which are the two basic polarity conventions. The trough represents the top of the sand in the SEG convention while the peak represents the top of the sand in the Anti-SEG convention. The Anti-SEG convention was used which is what is acceptable in SPDC. This can be demonstrated in the figure below;

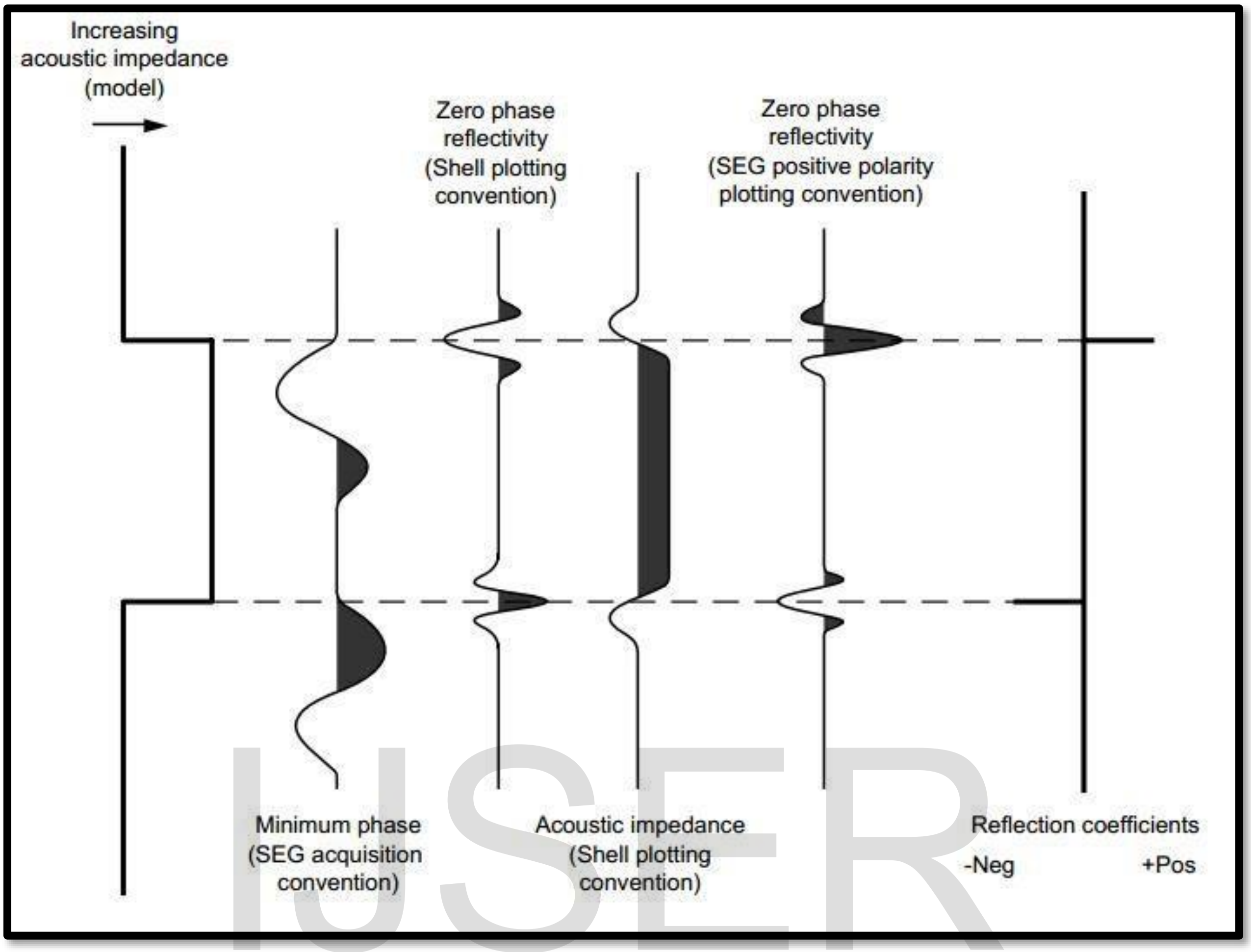

Figure 3.2. Polarity convention

A positive response gives rise to a soft kick which signifies that the top of the reservoir is soft while a negative response signifies a hard kick which implies that the top of the reservoir is hard. These are represented on seismic as blue and red loop respectively.

For this project, UTU 01 density and sonic logs were modeled to generate the lnϱv (acoustic impedance) which gives the acoustic impedance contrast of the lithology. The resultant synthetics were phase shifted in accordance with the European convention.

Question answered from the reflectivity pattern analysis includes;

- What should be the mapping strategy?
- What is the expected DHI?
- What could be the expected reservoir response on seismic

The result showed that the top of the A, B, C, D and E reservoirs were hard. The reflectivity pattern analysis was carried out using the UTU 01 check-shot and the result can be seen in the figure below;

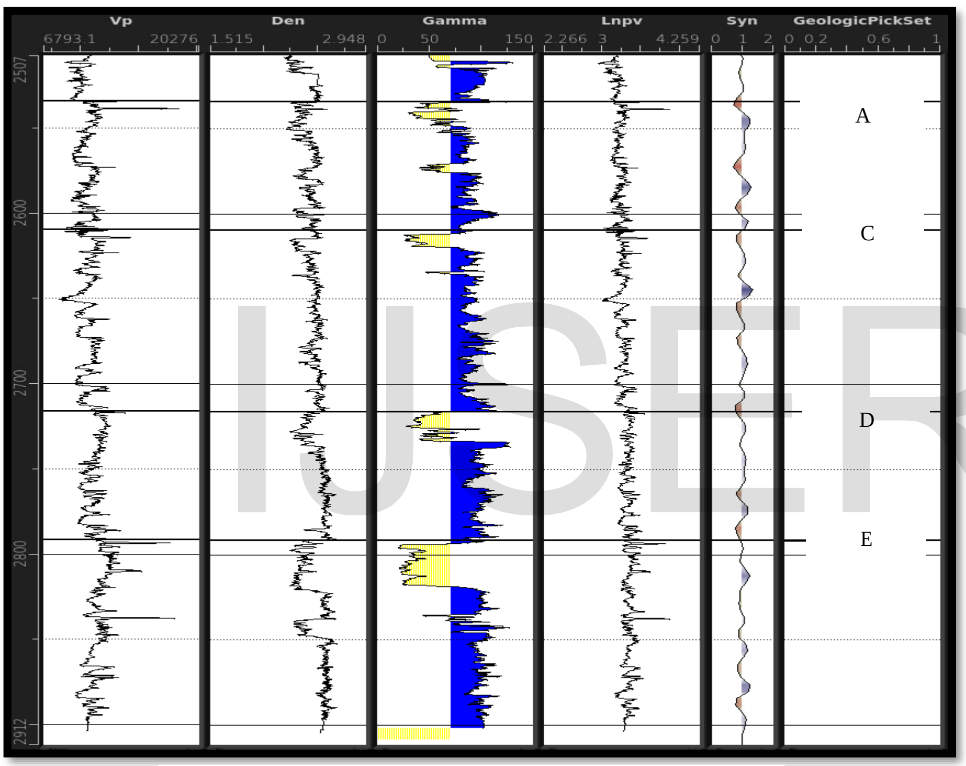

Figure 3.3. Reflectivity pattern analysis result

3.8 SEISMIC TO WELL TIE

This is a critical aspect of seismic data interpretation which is the process of tying the strong reflectors on seismic to events on the well. This is forward modeling the density and sonic logs to generate a synthetic seismogram to match the seismic reflections with the generated synthetic.

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Link between rock properties and seismic data are created from the synthetic seismogram using the convolutional model of the earth reflectivity response from the well and the seismic wiggles enabling us to determine seismic response at well location.

However, since seismic is recorded in time and borehole measurements are recorded in depth a time depth relationship is usually established using seismic velocity, checkshot velocity or VSP. Generated synthetic seismogram is used to verify the time depth relationship. The following are needed to generate a synthetic seismogram;

- Well logs (Density, Sonic, Gamma ray, Resistivity and Caliper)
- Seismic data
- Seismic wavelet
- Checkshot

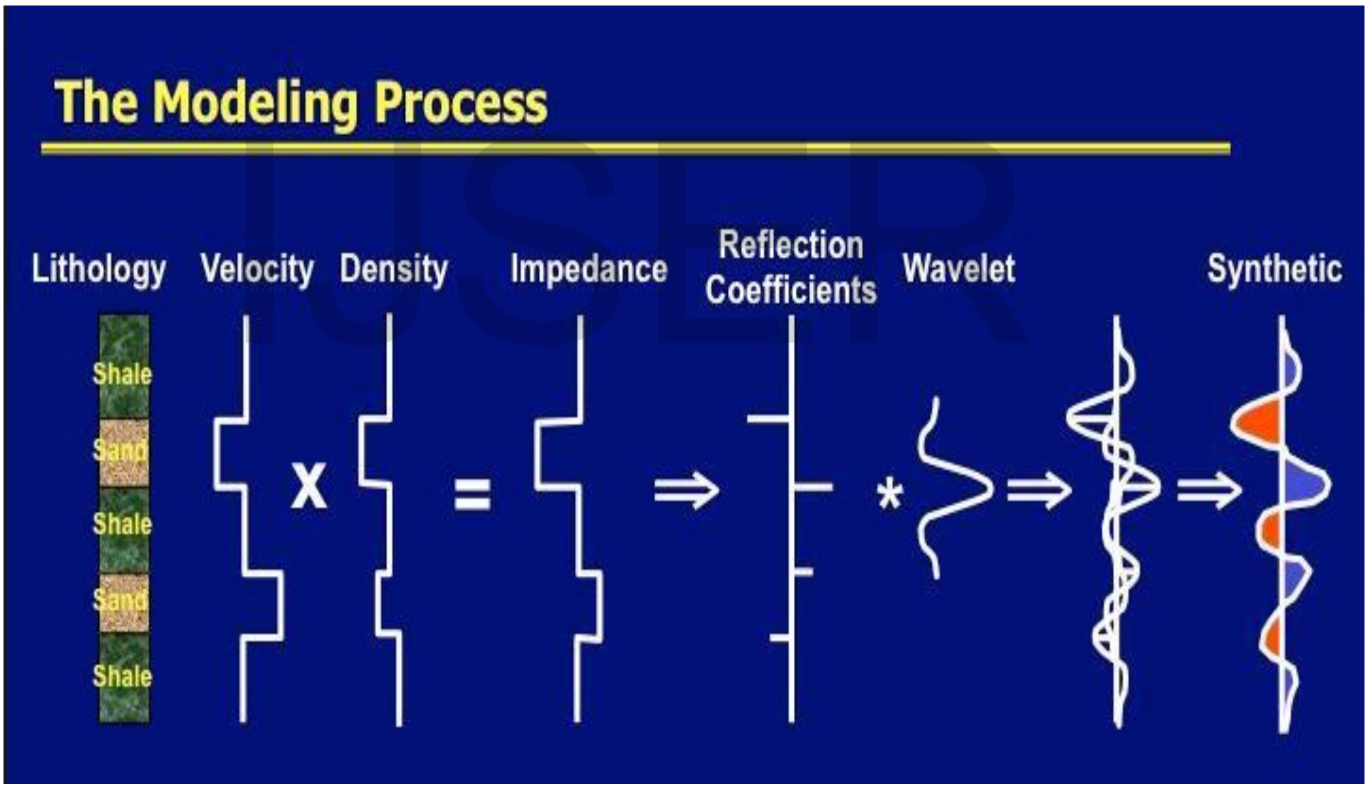

Figure 3.4. The earth convolutional model

For this project, the input to the seismic to well tie includes; UTU 01 check-shot, the density sonic logs and caliper logs.

A phase shift of 180 degrees was implemented. The tie was achieved using stretch and squeeze method with a bulk shift of 11.7ms. The seismic to well tie result is shown below;

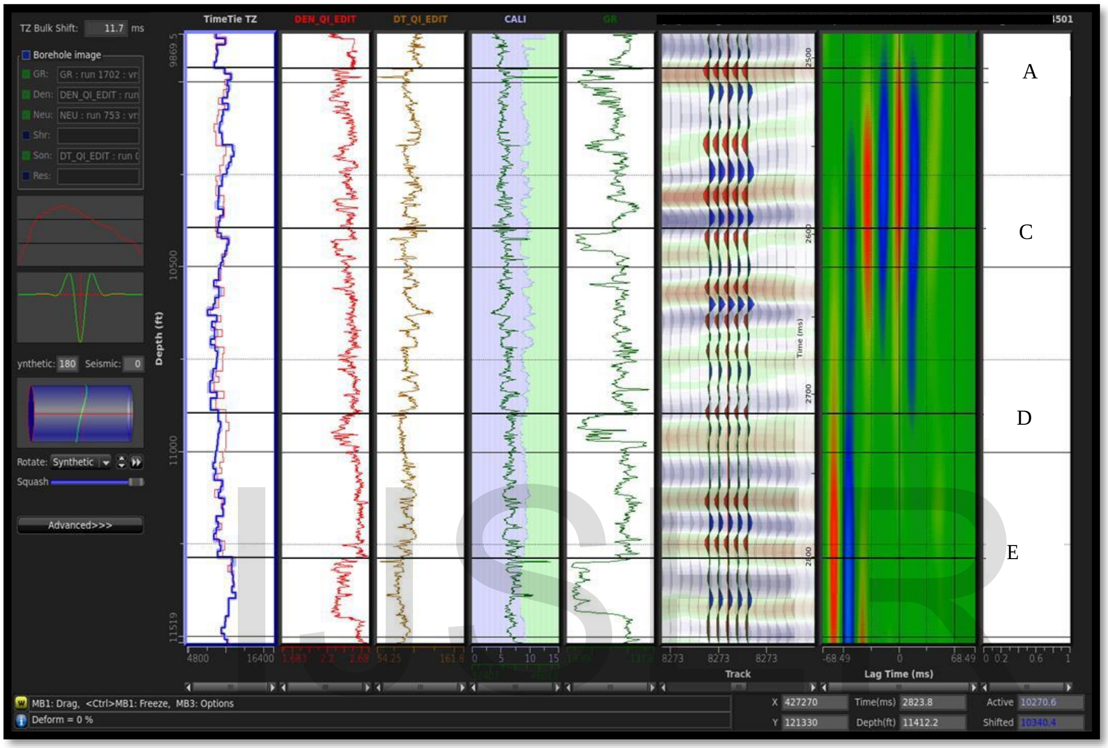

Figure 3.5. Seismic to well tie result using UTU 01 well check-shot

3.8.1 Benefits of seismic to well tie

- Used in structural interpretation because it enables the interpreter to identify the correct loops to interpret
- Wavelet estimation for seismic inversion and acoustic impedance generation
- Important in fluid contact detection/estimation

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- Update the TZ relationship for time to depth conversion
- Used in determining seismic dominant frequency

3.9 STRUCTURAL INTERPRETATION

This entails fault and horizon interpretation. However, certain tools like semblance cubes guide the seismic interpreter in picking the correct fault; it is a fault interpretation QC tool.

3.10 SEMBLANCE CUBE

Semblance or coherence is one of the widely used seismic attributes for identifying faults and fractures. It measures the degree of similarity or dissimilarity between adjacent seismic traces. Hence, it provides an efficient and objective way to visualize and identify fault geometry in seismic cube. Fault geometric attributes such as length, height, and fault segmentation can be extracted from such fault seismic attribute volumes.

It is a measure of the lateral changes in seismic response as a result of variation in structure, stratigraphy, lithology, porosity and presence of hydrocarbon. It often highlights faults in a seismic volume at a glance. It is also useful in detecting subtle stratigraphic features in map view.

For this project, an SOF semblance cube was generated using the 3D seismic volume full stack as shown below;

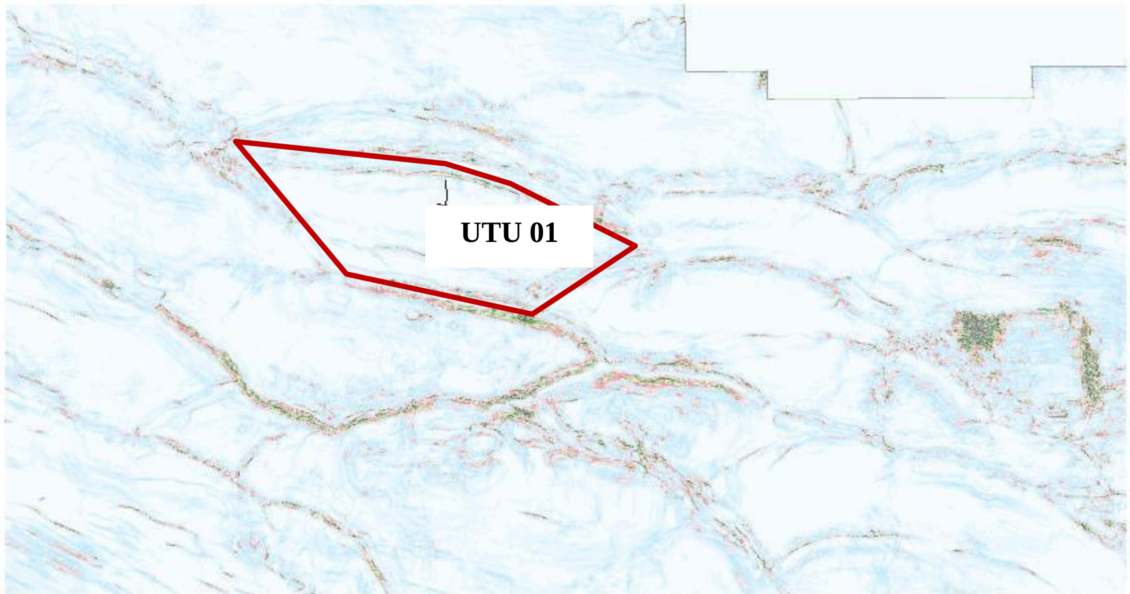

Figure 3.6. A semblance cube

3.11 FAULT INTERPRETATION

Faults are displacements caused by extensional and compressional forces beneath the earth surface. Faults can act as barriers to flow in reservoirs. Hence, fault interpretation in seismic data is a critical task that must be completed to thoroughly understand the structure and geometry of the reservoir. Development of similarity-based attributes allows geoscientists to effectively interpret seismic data and highlight the discontinuities that are often associated with fault systems.

Faults are identified as discontinuities or reflection cutoff during fault picking. Good knowledge of the structural styles and geology of the study area is important for the interpreter to be able to map the faults correctly.

For this study, faults were interpreted every 10 lines in the cross-line direction using a semblance cube as a guide to QC the fault at time 2500ms. The fault orientation was better seen and interpreted in the crossline direction. The interpreted faults were growth faults with rollover anticlines with faults trending from East to West typical of Niger Delta structural style.

However, major and minor faults were identified and interpreted during the fault interpretation. The major faults define the reservoir geometry they are referred to as synthetic faults which are the downthrown faults as a result of progradation while the few antithetic faults were identified and interpreted.
Fault interpretation is demonstrated in the figure below;

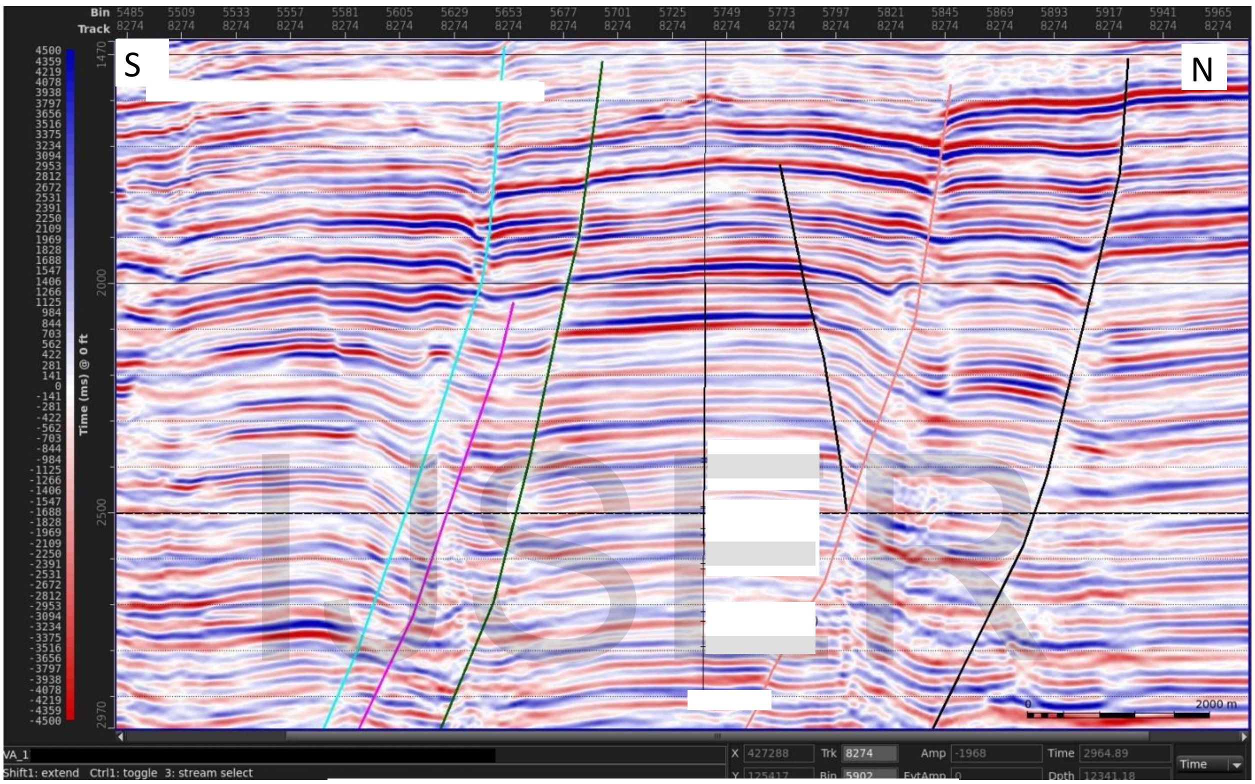

Figure 3.7. Fault Interpretation

3.12 HORIZON INTERPRETATION

Horizon interpretation methods includes, manual picking in traverse window and auto-tracking in the volume view.

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The velocity function from seismic to well tie is usually used to display the well tops so as to map the actual Horizons.

For this study, the interpretation honored fault throws and the interpreted faults were validated in the process. The tops of A, B, C, D and E reservoirs fell on the trough and zero-crossing respectively and they were interpreted every 10 in the inline and cross line direction at different time to define to capture the reservoir geometry.

Seed grids were generated for all these reservoirs which were later converted to surfaces to fill the spaces in-between the seed grids. The later s referred to as Time Maps.

Horizon interpretation is shown below;

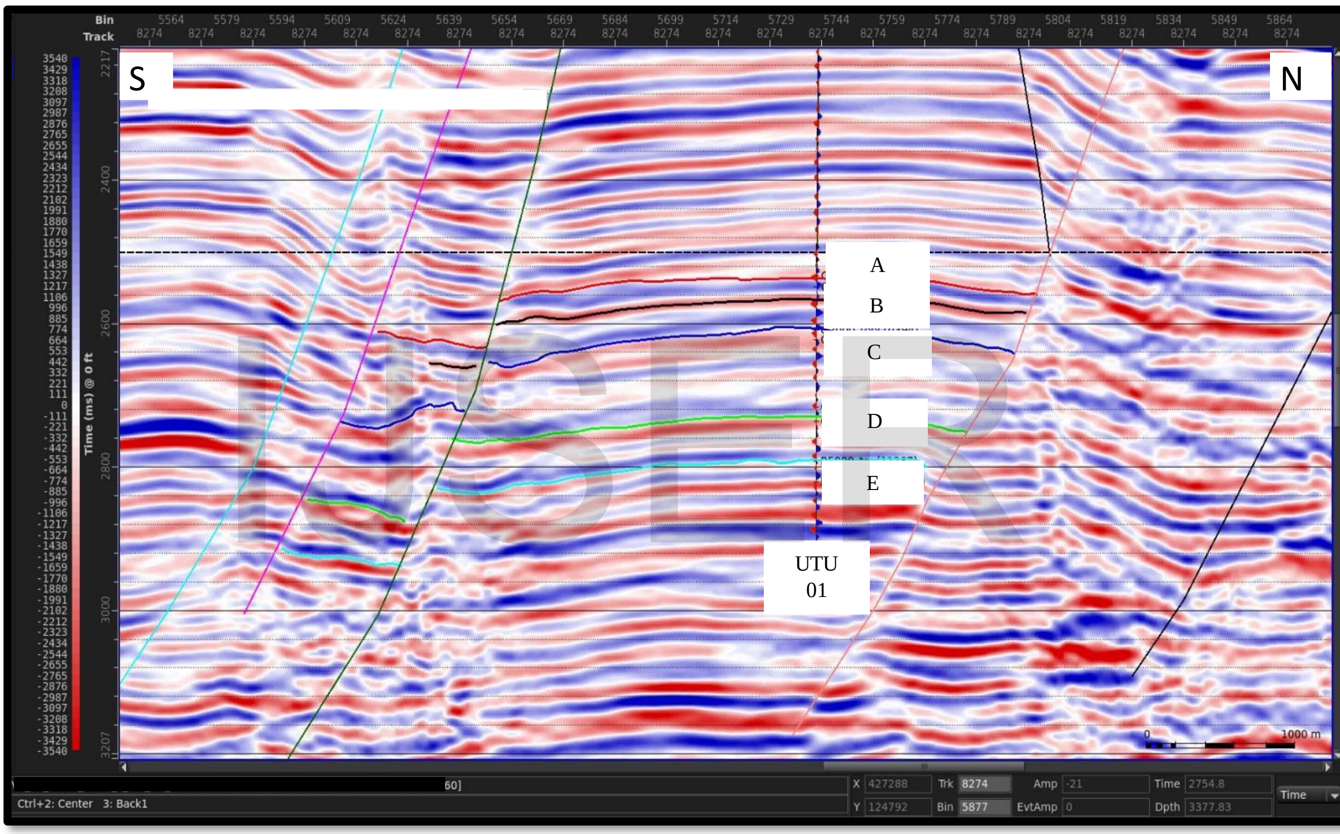

Figure 3.8. Interpreted horizons

3.13 VELOCITY MODELING AND TIME TO DEPTH CONVERSION

Since seismic data are interpreted in time and driller drill in depth. The need for accurate time to depth conversion exists because the discovered hydrocarbon accumulations exist in time due to time interpretation. Time to depth conversion is the process of converting interpreted faults and horizons from time domain to the depth domain. The time to depth conversion is a critical element in the overall seismic interpretation process. Results from depth conversion enables the E&P industry to calculate the available hydrocarbon accumulation in the reservoirs of interest and guides in reserve booking and decision making process. For example, a lateral variation in velocity could indicate lithological changes or differences in burial/uplift history

Velocity increases with depth as a result of compaction, digenesis and overburden effect. Hence, an accurate velocity model that will honor the Geology is usually built to account for the lateral velocity variations and accurately depth convert the time event. Clastic sedimentary rocks experience velocity increase with depth.

However, sparse velocity information derived from existing wells is inadequate to account for lateral velocity variations. Hence, Seismic time to depth conversion is usually problematic due to large variables influencing the velocity such as porosity, compaction, under-compaction and digenesis making it difficult to derive accurate velocity information. A probabilistic model of velocity may be more realistic since there is no unique velocity solution

To build a velocity model, care is taken to ensure that it incorporates geological lateral velocity variations and all available well information. Different methods of velocity modeling exist but the choice of the method to adopt is dependent on the average residual when tied to the well tops after depth conversion. The method with the least residual is adopted for time to depth conversion

3.13.1 Purpose of Velocity modeling

- Prognosis of well formation tops
- Well trajectory planning
- Estimation of prospects and field hydrocarbon volumes
- Regional scale maps for basin modelling

3.13.2 The time to depth conversion is a HSE critical activity and it is related to the following

- Formation tops, fault intersections, prediction of fluid fill for exploration, appraisal and developmental wells
- Formation pore pressure, fracture gradient and borehole stability prediction for exploration,

  Appraisal and developmental wells, well entry and abandonment projects.

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3.13.3 Time to depth conversion is related to the following DCAF controls

- End of well report
- Well proposal
- Well function specification
- Pore pressure prediction report
- Static and structural modeling

3.13.4 The depth conversion method includes

- Polynomial function method
- The V0, K method

- The seismic velocity method

3.14 POLYNOMIAL FUNCTION METHOD

This is usually calculated using the updated velocity derived from seismic to well tie process. The updated velocity function displays both the two-way time (TWT) and the true vertical depth subsea (TVDSS) when plotted in a spreadsheet.

This is then copied to an excel spreadsheet from which a plot of TVDSS against the TWT is made. A third order polynomial equation with a trend line is generated from this plot. The accuracy of this method is directly related to the polynomial order. Hence, the higher the order of polynomial the more accurate it is. Values of the TVDSS versus TWT are estimated around the area of interest by taking values at regular order using a third order exponential equation. This can be demonstrated using the plot below;

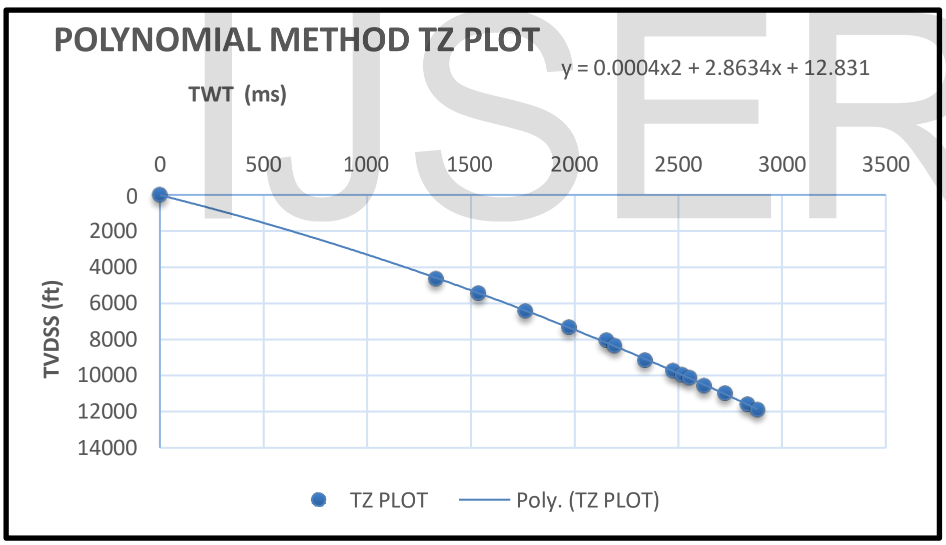

Figure 3.9. Polynomial function method TZ Plot

3.15 VO, K METHOD

The TWT (ms) and the TVDSS (ft) inputs were generated from seismic to well tie using UTU 01 well. This method was adopted for this study due to its ability to account for compaction with depth. It can be approximated with linear regression of well data.
Mathematically, it is given by; V=V0 +KZ. where K is the compaction coefficient.

The function above defines velocity as a function of depth. In the T/D conversion process only "T" is known a priori and depth is the parameter to be solved.

V0, K breaks down in case of;

- Few well control
- Lateral facies change / diagenesis change
- Invasion area
- Well covers little depth spread

The depth of a certain horizon is given by the equation;

$$Z_1 = \frac{V_0}{k} \cdot \left(e^{k \cdot t_1} - 1\right)$$

$$Z_2 = \left(\frac{V_0}{k} + Z_1\right) \cdot e^{k \cdot \Delta T} - \frac{V_0}{k}$$

Z_1 = base layer 1 depth, Z_2 = Base layer 2 depth, t_1 = Base layer 1 time, ΔT = Delta travel time

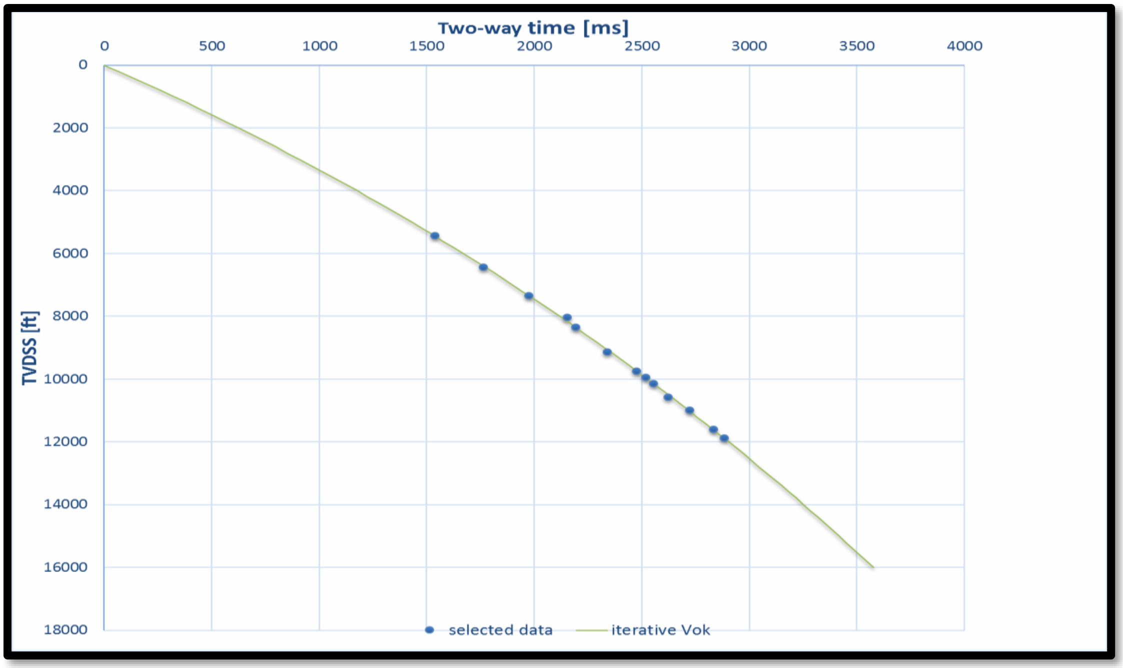

Figure 3.10. V0, K TZ plot

3.16 STRUCTURAL FRAMEWORK

A structural framework is usually built to properly capture the reservoir geometry and architecture. It is a non-unique solution which is built using the depth converted events. For this project, the depth converted fault and horizon interpretations were imported into Petrel. They were quality controlled for consistency in the fault dip, modeled and pillar gridded to get achieve a structural model. These are shown in the diagrams below;

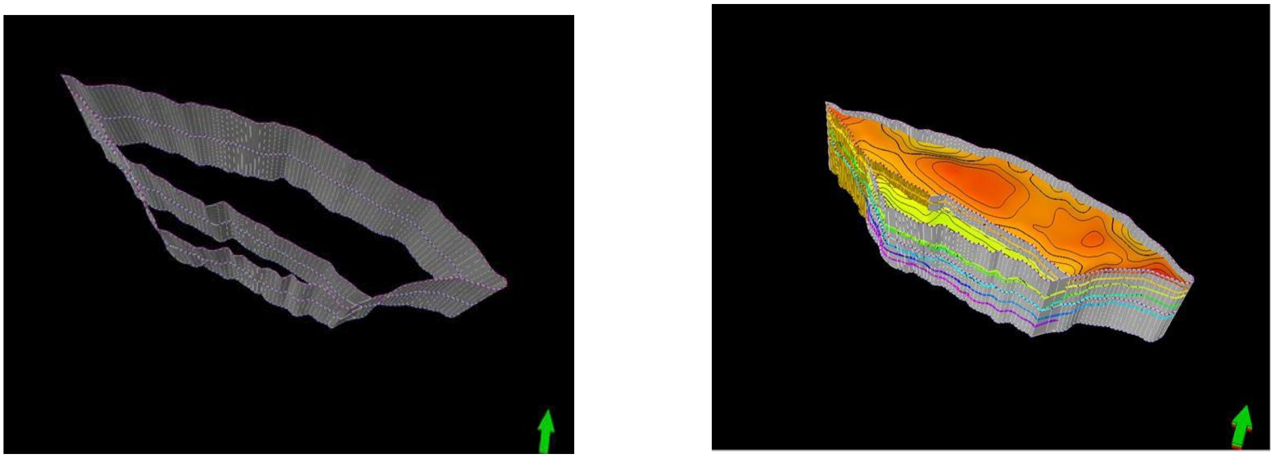

Figure 3.11. Fault framework without horizons (Left) and fault framework with horizons (Right)

3.16.1 Benefits of structural framework

- Shows fault cutoffs and errors quickly
- It allows QC of fault throws
- Allows us to quickly ensure that we have a water tight model

3.17 ATTRIBUTE EXTRACTION

This is a process of extracting amplitude maps for the interpreted horizons of interest which may include localized amplitude anomaly associated with the geology.

Seismic attributes are features that helps seismic interpreters to better visualize, analyze, quantify and map geological features associated with hydrocarbon accumulation. It's a powerful tool that helps in improving the accuracy of interpretations and predictions in hydrocarbon exploration and development process. The purpose of seismic attribute analysis is to identify and map the possible DHI's such as the bright spots and dim spots. It offers information on the lithology, porosity and fluid contact estimation.

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These allows Geoscientists to interpret faults, channels, depositional environments and unravel structural deformations. They are useful in checking the quality of seismic data for artefact delineation, seismic facies mapping, prospect identification, risk analysis and reservoir characterization. A good seismic attribute is sensitive to geological features or reservoir property and allows us to define the structural or depositional environment and thereby infer properties of interest. 3D seismic attribute can be applied in the delineation of structural features and depositional environments.

Amplitude maps are the output of an amplitude extraction process. Presence of bright spots and dim spots on amplitude maps signifies presence of hydrocarbon accumulation.

Hydrocarbon are often seen around the crest due to buoyancy effect. Major faults on the other hand forms major traps and amplitudes found around faults and enclosed by contours are said to be conformable to structure while scattered amplitudes are said to be non-conformable to structure.

For this project, however, amplitudes were extracted from Zero Line from reflectivity data using different windows.

3.17.1 Benefits of Attribute Analysis

- Reservoir characterization
- Mitigation of drilling risk
- Prospect identification
- Fluid contact estimation

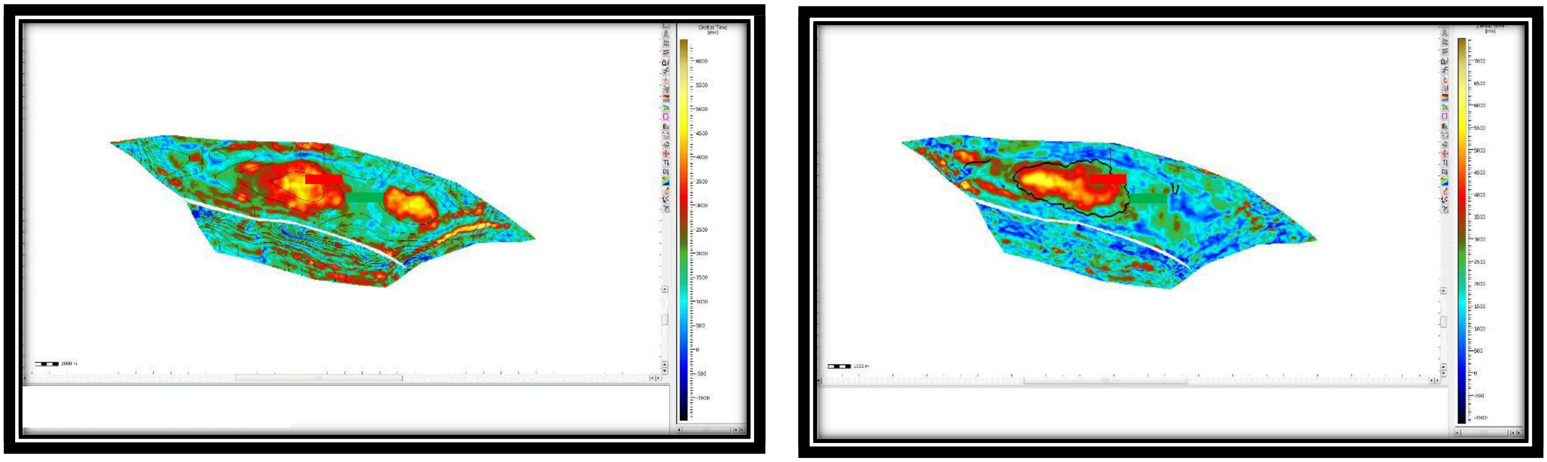

Figure 3.12. Generated amplitude maps

3.18 INVERSION

Inversion is a backward modeling process of transforming seismic reflection data into quantitative estimate of rock property. As such, a rock property gives a better description of a reservoir. Hence, inversion is a non-unique solution.

Since seismic frequencies is between 8-40Hz, implicit in this approach is the integration of a low frequency model information into high frequencies from the seismic. This is important since low frequencies are present in logs but absent on seismic and are required in inversion to make it broadband. However, the low frequency result of the impedance inversion is neither stable nor reliable. The Merge Cutoff Frequency is used to decide the transition between the log based low frequency model and the seismic-based inversion result. Choosing a suitable value for the cutoff frequency is an iterative process.

The low frequencies from 3D solid model is defined from interpreted horizons and generated impedance logs. It is important to understand the a priori log information on the final inversion. Hence, the goal is to transform high frequency seismic information into a reasonable geologic information using a low frequency model. There are three steps to building aa low frequency model which includes;

- Creating a framework based on interpreted horizons
- Generate a broadband model based on the AI calculated from well logs, propagated throughout the volumes following the horizons
- A low pass filter is used to filter the broadband to yield a low frequency model.

Typical low frequency model is shown below;

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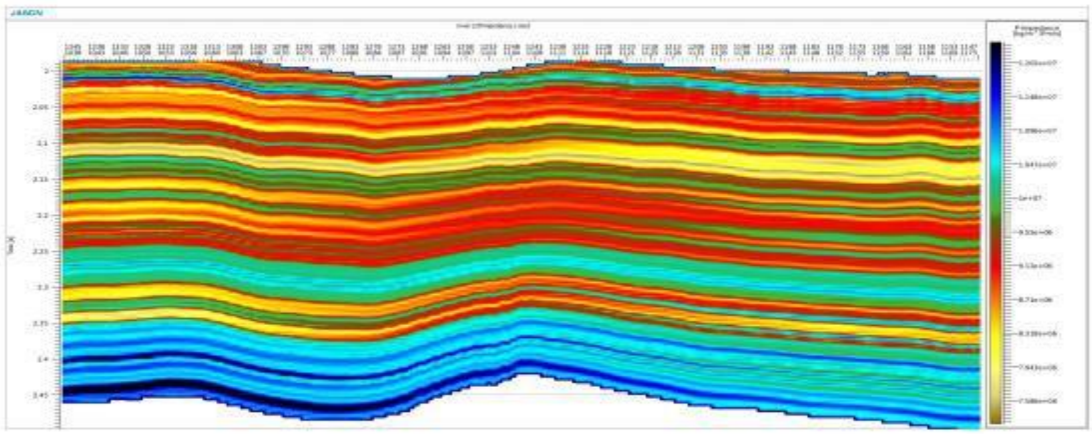

Figure 3.13. Low frequency model

3.18.1 Seismic inversion data input includes;

- Estimated wavelets
- Estimated horizons
- Trace gate
- QC wells
- QC time gate
- QC traces

Testing of sensitive QC parameters is an important aspect of inversion

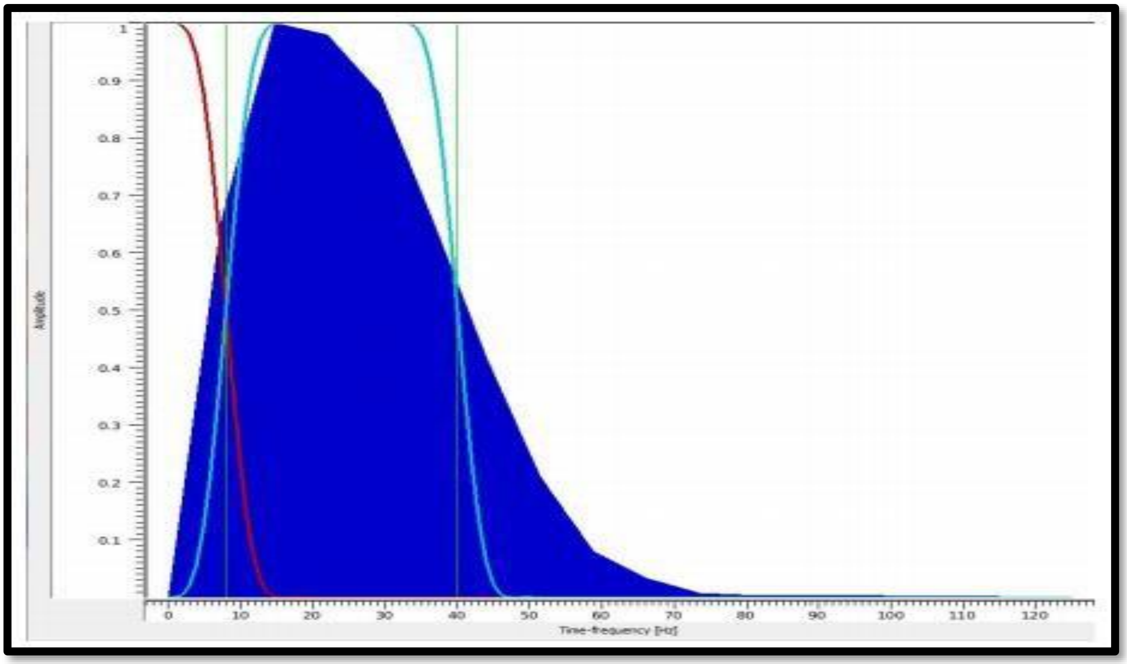

Figure 3.14. A low pass filter (8Hz) for the low frequency model is shown on red, the light blue represents the bandpass filter for the initial inversion result while the solid blue is the spectrum of the seismic data for field.

Misfit in P-impedance, seismic signal to noise ratio, cutoff frequency, wavelet scale factor will ultimately affect the inversion result. High signal to noise ratio will lead to a high correlation between the synthetic and seismic data. Contrast Misfit P-impedance Uncertainty controls the scarcity of the reflection coefficient sequence. If it is small, the reflection coefficient sequence is sparser. The wavelet for inversion is the average wavelet from two wells' wavelet estimations. Since the inversion time gate is different from the wavelet estimation time gate, it is important to set the Wavelet Scale Factor Seismic to a suitable value.

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On	QC parameter	Info	Current	Lower	Upper	Select
	Contrast misfit P-Impedance uncertainty		0.0066	0.002	0.05	☑
	Seismic misfit signal to noise ratio penobscot_2800 [dB]		13.23			☐
	Seismic misfit power		1.55			☐
	Wavelet scale factor penobscot_2800		2.6			☐
	Merge cutoff frequency [Hz]		8			☐

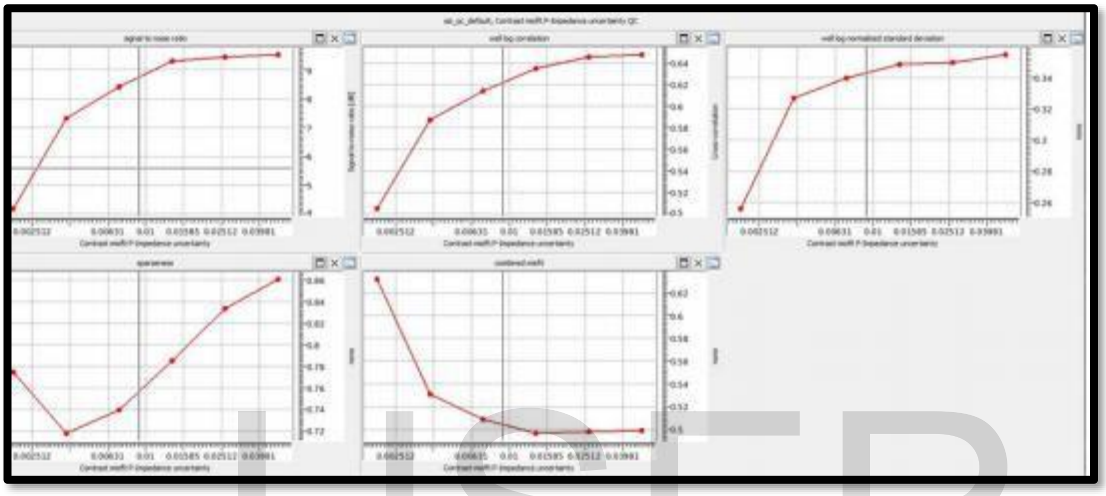

Figure 3.15. Wavelet QC

3.18.2 Earth Model building

The first step in model building is to design the structure. This is done by providing two pieces of information - the interpreted horizons and the model "framework". The framework, in the form of a spreadsheet, describes the ordering of the horizons in space and time and their behavior at faults. The horizons, which can include interpreted faults, provide structure information. Together, these form a blueprint for the model. The model is completed by populating it with geophysical information, usually input in the form of well log data. We are most interested in impedance since this is needed to complete the low frequency portion of the seismic inversion.

3.18.3 ACOUSTIC IMPEDANCE

Acoustic impedance is a layer property which is a product of seismic velocity and density. It is therefore a rock property that can be used to characterize a reservoir. It can be derived from seismic inversion process. For instance, hydrocarbon fill is usually associated with low acoustic impedance contrast produces high porosity

Seismic reflection data, are generated by changes in acoustic impedance contrast between geologic formations. This can give a more detailed and accurate structural, stratigraphic, lithologic and fluid distribution properties than that obtained from conventional seismic interpretation. Moreover, some production information such as net pay and average porosity maps can be generated from reservoir characterization results. Several algorithms have been developed to estimate acoustic impedance from seismic data such as discrete recursive algorithms, that compute acoustic impedance from the reflectivity coefficients. They assume that seismic amplitudes are proportional to reflection coefficients.

This method is also described as band limited, because the resulting acoustic impedance will contain the same frequency content as the input seismic data. These algorithms are fast and reliable but are unstable at high values of reflection coefficients and noise spikes. Large reflection coefficients and noise or erroneous spikes (large amplitude spikes compared to the spikes in the reflectivity series) will cause large acoustic impedance values that will give rise to instability during the inversion.

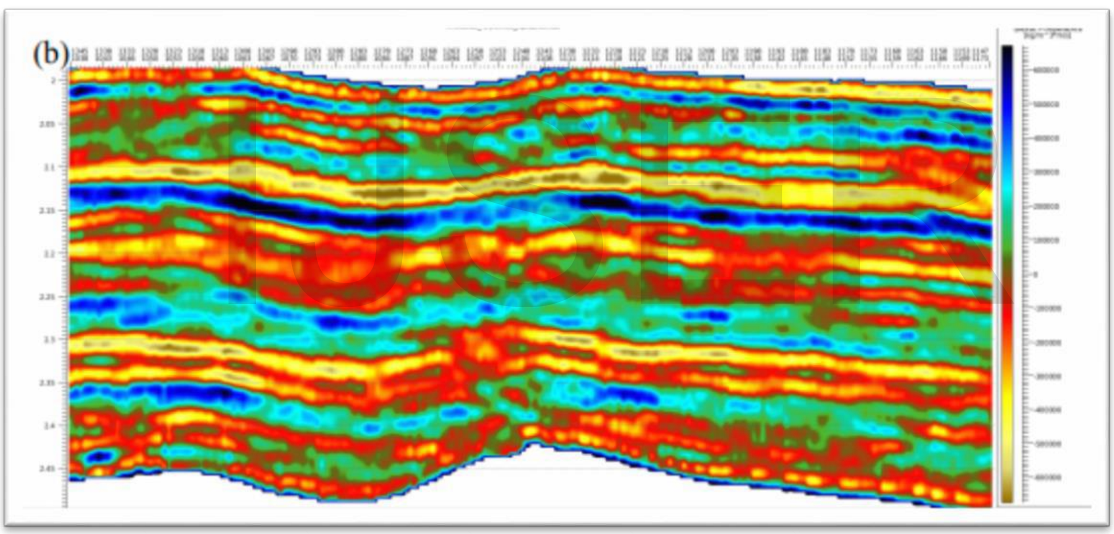

Figure 3.16. Acoustic Impedance AI volume

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SEISMIC INVERSION PROCESS

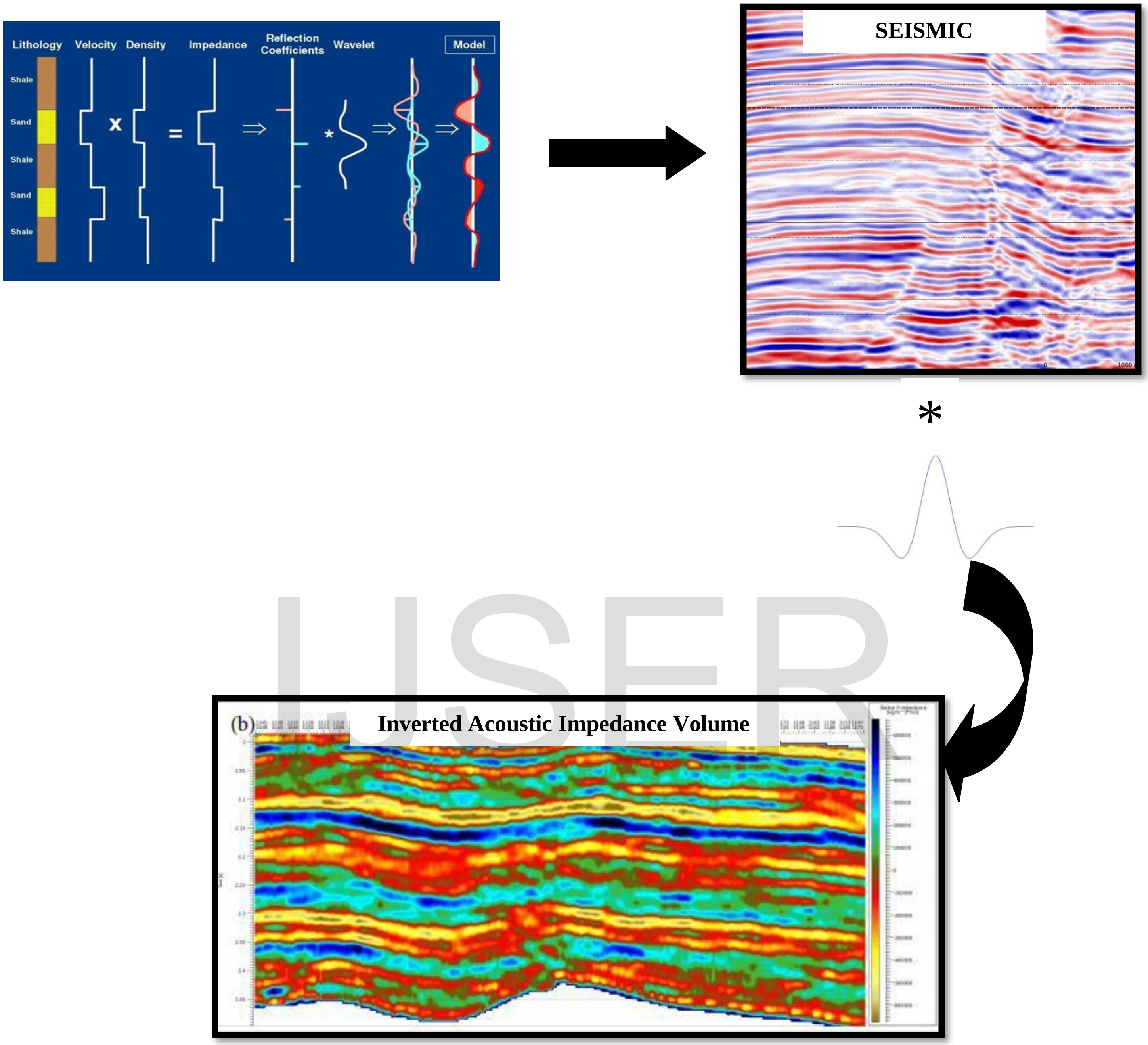

Figure 3.17. Seismic inversion process

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3.18.4 INVERSION BENEFITS

- Removes tuning effect
- Reservoir characterization
- Well placement
- Gives lithology information / indicator
- Layer properties
- Higher resolution of layer thickness
- Increases bandwidth

3.18.5 LIMITATION

- Band limited
- Non-unique solution
- Limited lithology prediction

3.19 FLUID CONTACT ESTIMATION

Fluid contact is the bedrock of the E&P business since absence of fluid contact means absence of hydrocarbon and hence no business prospect.

For this study, fluid contact estimation was carried out for the A, B, C, D and E reservoirs to resolve the fluid contact uncertainty issues in the sands. And to enable economic evaluations in the reservoirs of interest.

A polygon was drawn at different angles on the generated amplitude maps and the depth converted events. A corresponding amplitude versus depth cross plot was generated showing amplitude contrast between the hydrocarbon and water. The fluid contact values were read off at the point where density contrast happened. This was done independently for A, B, C, D and E reservoirs.

The generated values were passed on to the PG and RE for volumetric estimation. This however, served as the bedrock for the static modeling, dynamic modeling, economic analysis and production forecast.

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CHAPTER FOUR

RESULTS AND DISCUSSIONS

4.1 REFLECTIVITY PATTERN ANALYSIS

The density and sonic logs from UTU 01 well was modeled to understand their seismic response in relation to the acoustic impedance contrast of the tops of A, B, C, D and E reservoirs. The resultant acoustic impedance log from the modeling showed that the top of the reservoirs was hard as a result of compaction, diagenesis and overburden effect with depth. Hence, the result form the reflectivity pattern analysis corresponded to the seismic to well tie result. This result in shown in the diagram below;

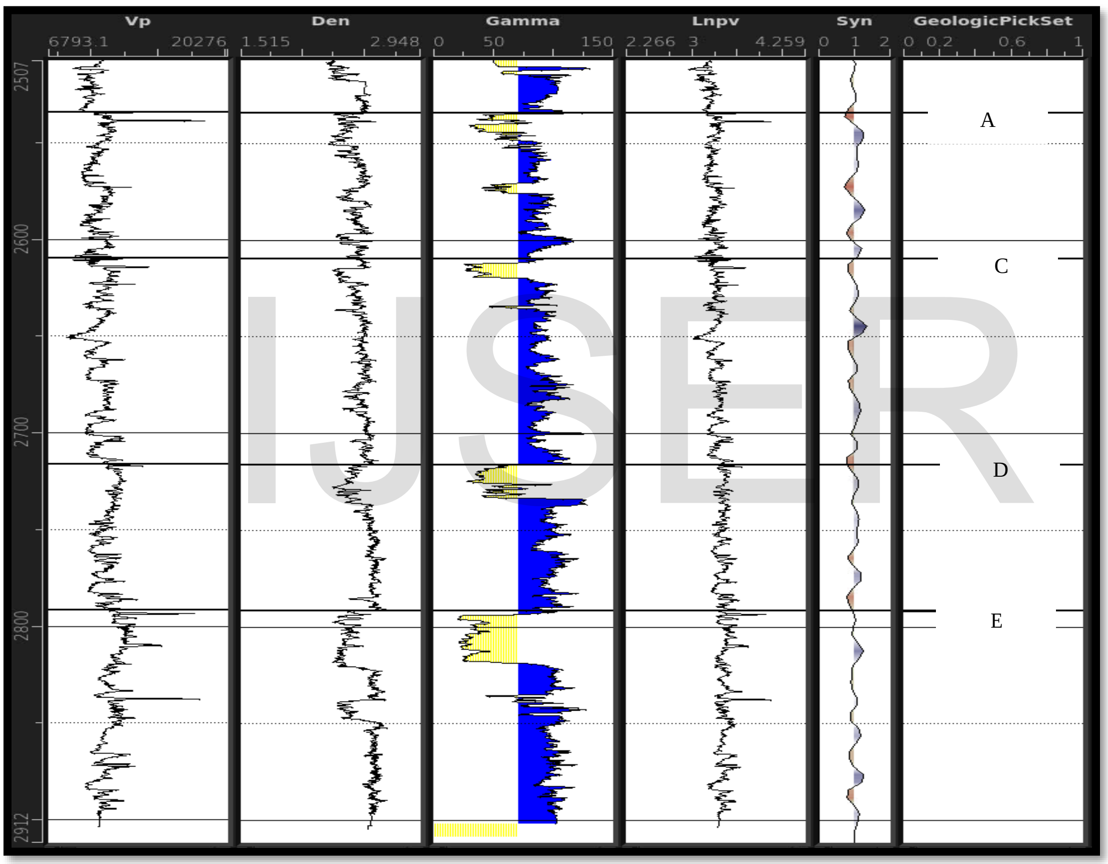

Figure 4.1. Reflectivity pattern analysis result using UTU 01 checkshot

4.2 SEISMIC TO WELL TIE

This was done using UTU 01 Checkshot. The density, sonic and caliper logs were used to conduct the seismic to well tie. A phase shift of 180 degrees Anti-SEG convention was implemented. A good tie was generated at 11.7ms using stretch and squeeze method. The result showed that the top of A, B, C, D and E reservoirs were hard which corresponded to the reflectivity pattern analysis result. However, the resultant velocity function, wavelet and logs were saved for further interpretation. The seismic to well tie result is shown diagrammatically below;

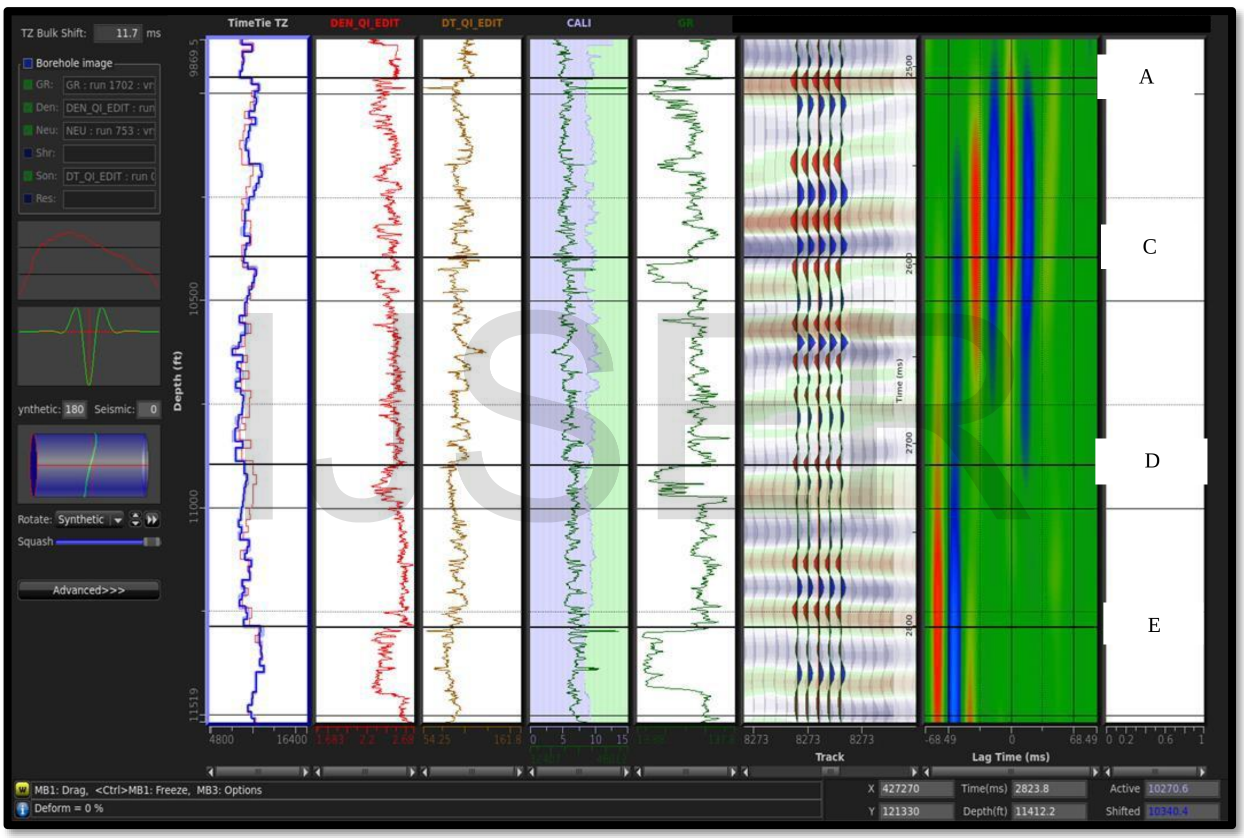

Figure 4.2. Seismic to well tie result using UTU 01 Checkshot

4. 3 SEMBLANCE MAP

An SOF semblance cube was generated from a full stack 3D seismic volume. The resultant semblance cube was effective in identifying faults and fractures. It was used to guide and QC fault interpretation. The result of the semblance map QC process shown in the figure below;

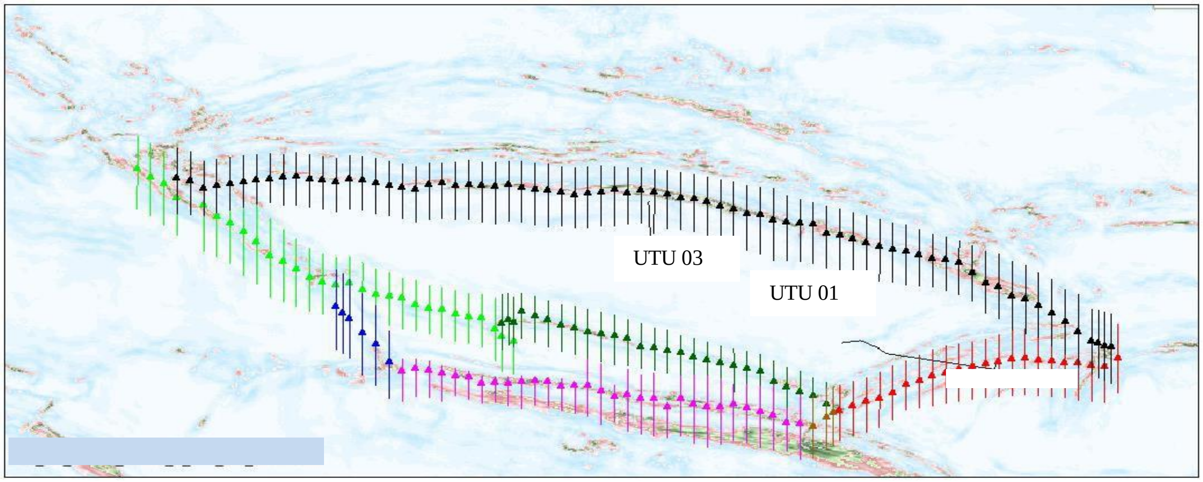

Figure 4.3. Interpreted faults on SOF Semblance Cube

4.4 FAULT INTERPRETATION

Faults were interpreted every 10 spacing in the cross-line direction. This is because fault orientations are more visible in the crossline direction.

The result from the fault interpretation showed that the interpreted faults were lytric fault with rollover anticline bounded in the North and South my major bounding faults. The UTU structure was defined structurally by six (6) faults, four major faults and two intra-reservoir faults. the faults were growth faults which is typical of Niger Delta structural style. The interpreted faults re displayed in the figure below;

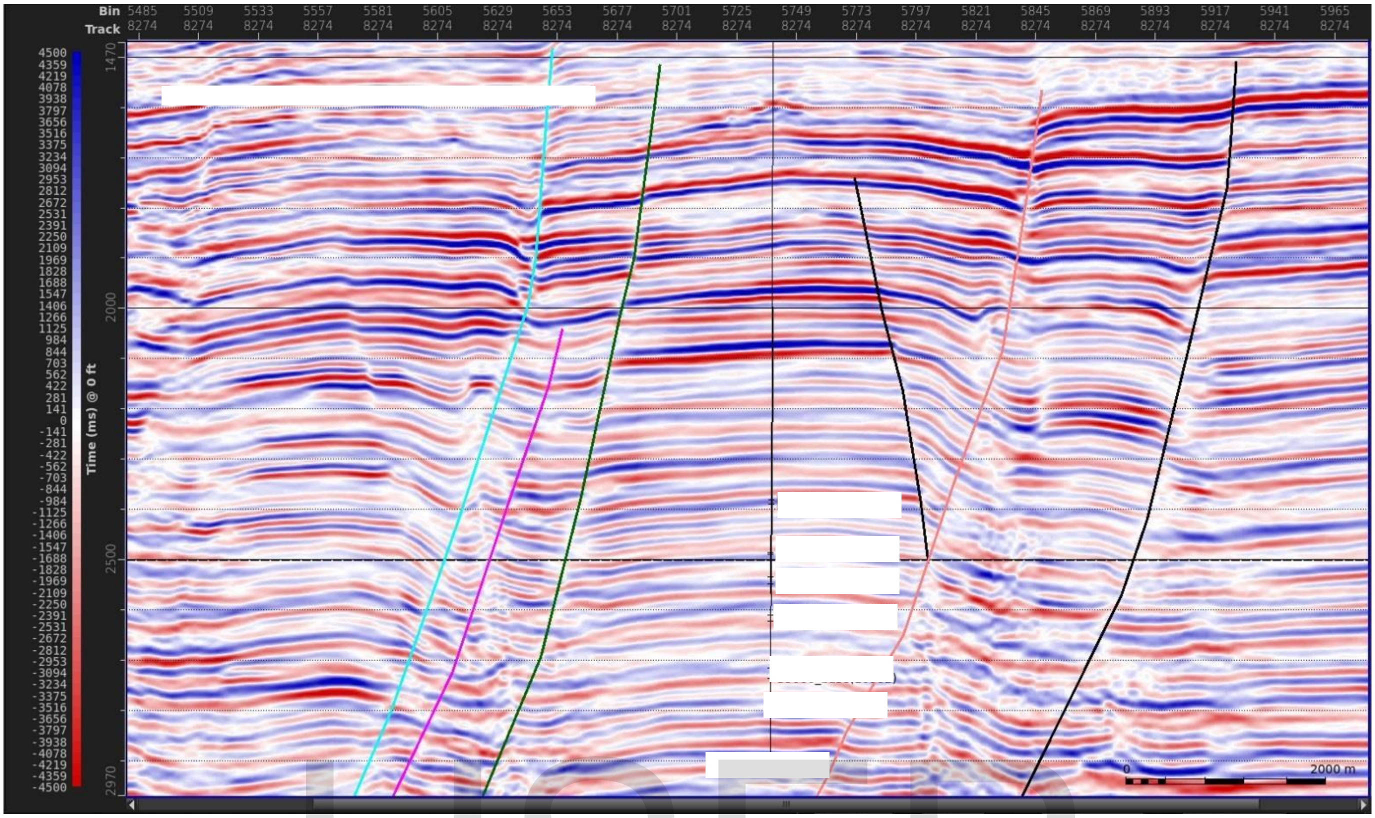

Figure 4.4. Fault interpretation faults in traverse view

4.5 HORIZON INTERPRETATION

Horizon interpretation was done to accurately define the reservoir geometry and architecture. The velocity function from the seismic to well tie was activated in the traverse to enable accurate mapping of the top of the reservoir as seen by the well. The generated synthetic, well and well tops were displayed to ensure that the correct loops were mapped. The figure below shows the horizon interpretation.

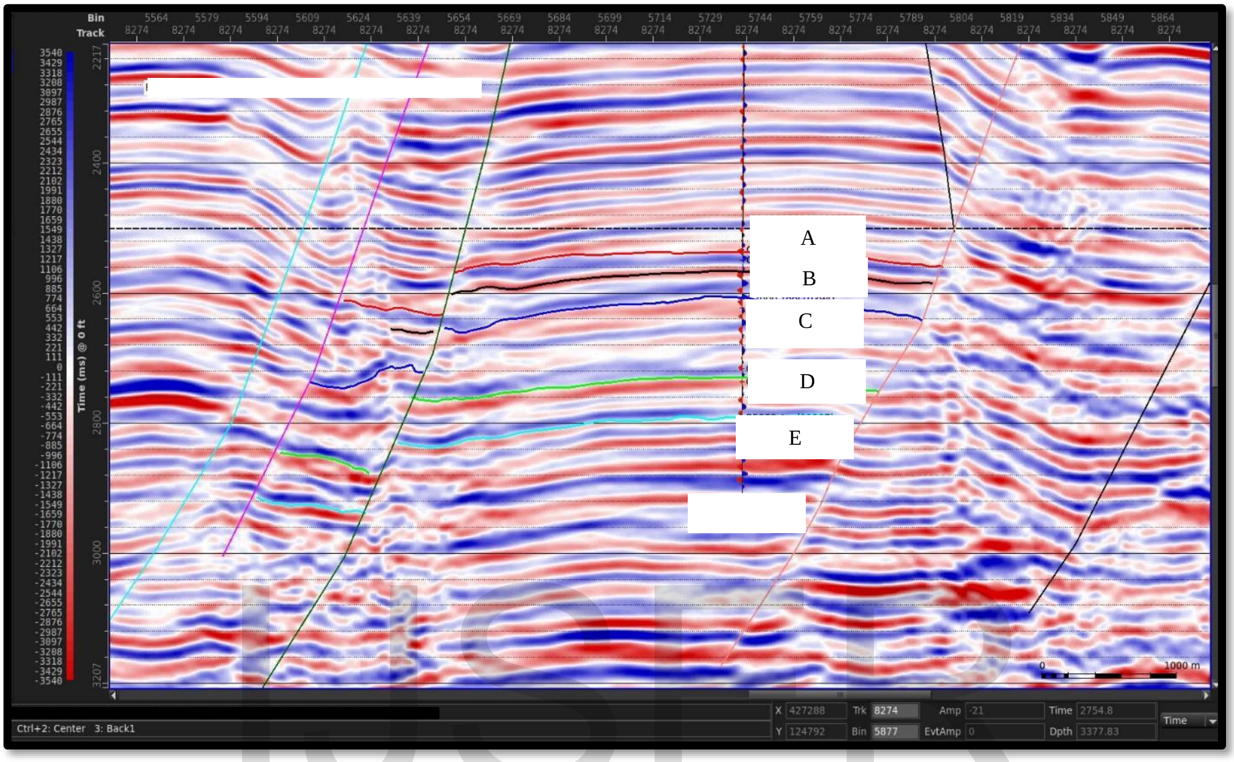

Figure 4.5. Horizon interpretation in traverse view

4.5.1 SEED GRIDS

The horizons were interpreted manually every 10 in the inline and crossline direction forming seed grids for A, B, C, D and E reservoirs in the process. The interpretation honored fault throws and some interpreted faults were updated in the process. generated seed grids for A, B, C, D and E reservoirs are shown diagrammatically below;

Figure 4.5.1. Seed grids generated from Horizon interpretation

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4. 6 TOP STRUCTURE MAPS (TIME MAPS)

The spaces in between the seed grids were filled to make a top structure maps (time maps).

This shows the actual reservoir geometry. The result from this showed the kind of closure present which was a four-way deep closure. The generated top structure maps for A, B, C, D and E reservoirs are shown below;

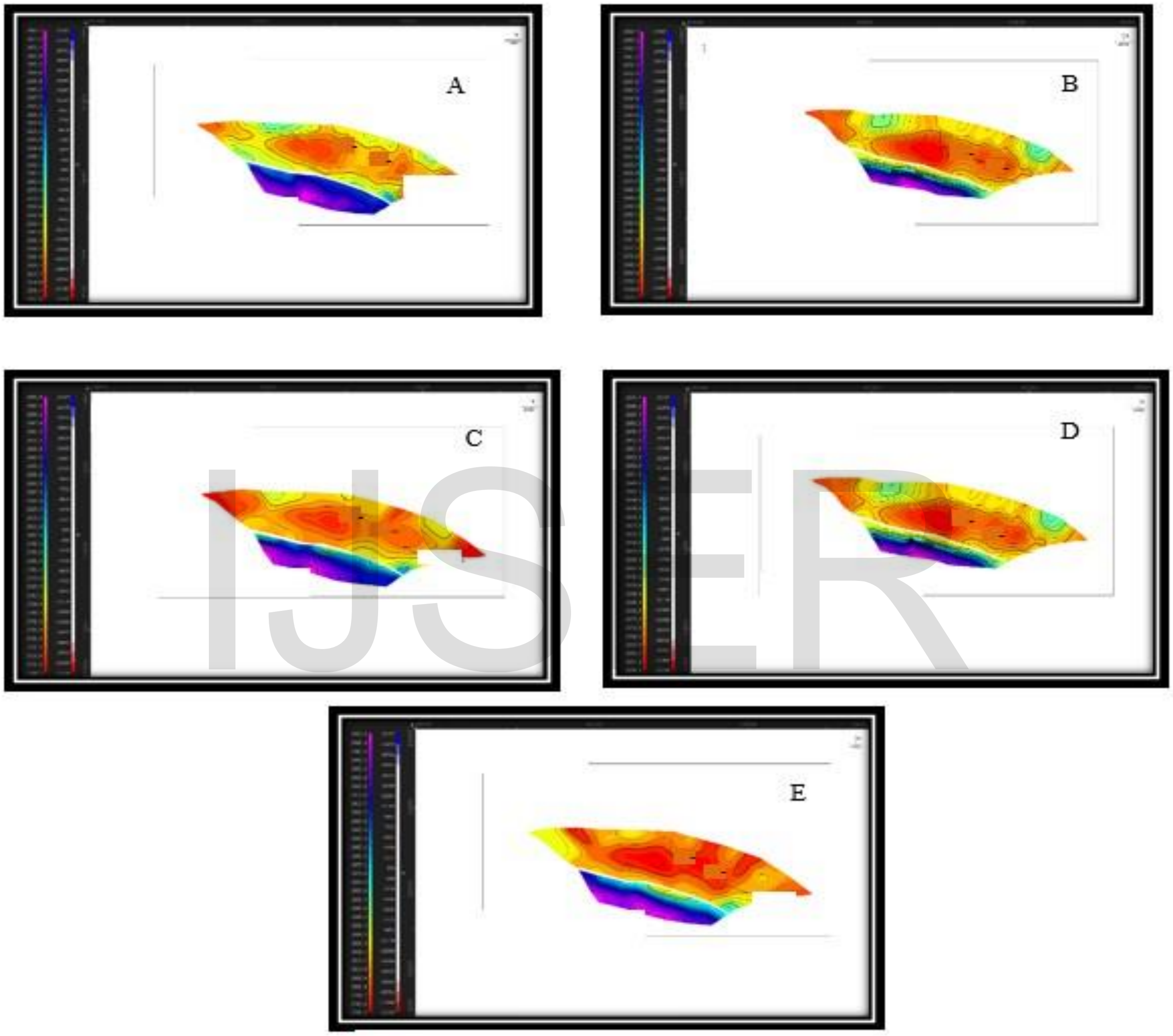

Figure 4.6. A, B, C, D and E Time maps

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4.7 VELOCITY MODELING AND TIME TO DEPTH CONVERSION

Two velocity models were built to properly depth convert time events and account for lateral velocity variation away from the well location. They are the polynomial function method and the V0, K method respectively.

UTU 01 well checkshot was used for velocity model building and subsequent time to depth conversion after analyzing their residuals.

TZ plots were generated for the two methods respectively. The plots showed a consistent increase in velocity with depth which is typical of Niger Delta classical normal compaction trend. This can be shown below;

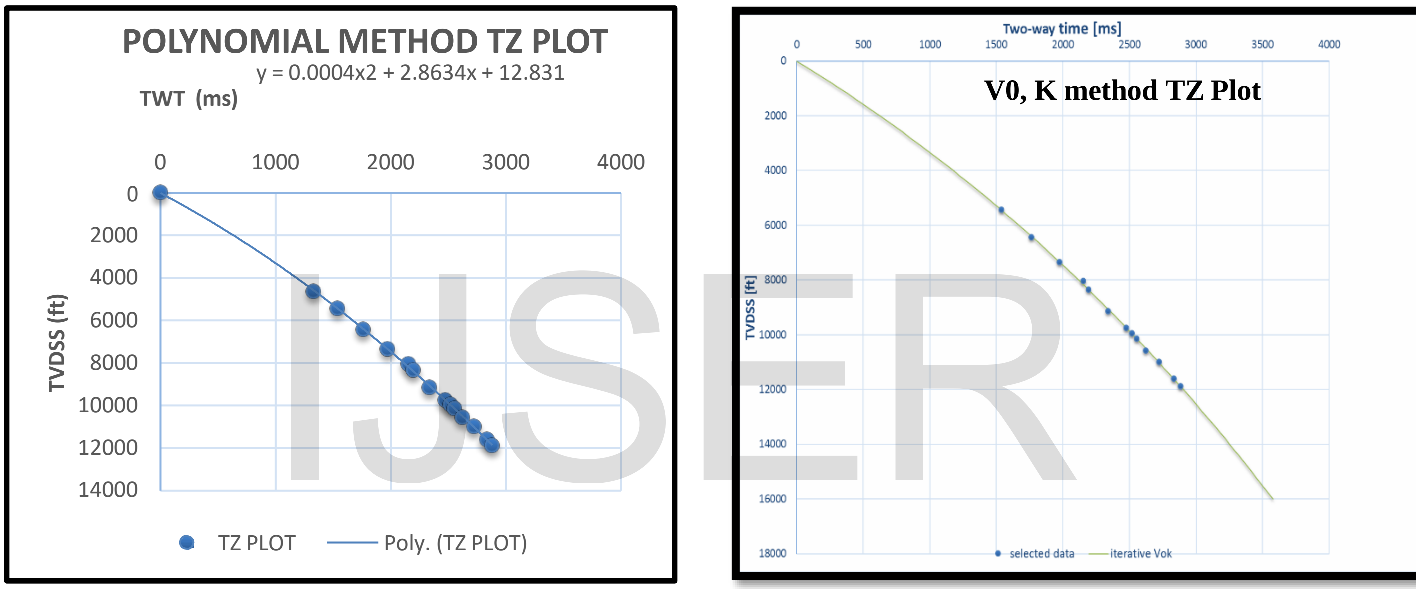

Figure 4.7.1. Polynomial function method (Left) and V0, K method (Right) TZ plots using UTU 01 well checkshot

The generated velocity models were used for time to depth conversion of time events. The residuals from the depth conversion was analyzed to determine the method with the least residual. The V0,

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K method was adopted for time to depth conversion because it gave the least residual and accounts for compaction with depth. The result of the residual analysis is shown in the table below;

Table 4.7. Residual analysis

			POLYNOMIAL METHOD		V0, K METHOD	
Well	Reservoir	MD (ftss)	Initial Residual	Final Residual	Initial Residual	Final Residual
UTU 01	A	10030	-66.17	-0.32	-22.68	-0.92
UTU 01	C	10463	40.67	0.67	-2.32	-2.32
UTU 01	D	10966	-50.55	-1.45	-88.1	-0.28
UTU 01	E	11356	-1.89	-1.89	37.7	1.68
			POLYNOMIAL MTHD. STD = 53.09		**V0, K MTHD. STD = 52.54**	

4.8 DEPTH MAPS

The depth converted events were tied to well tops after residual analysis by applying a bulk shift relative to the residual value. This output served as an input to the static model built by the PG. The generated depth maps were also useful in determining the depth of the A, B, C, D and E reservoirs as well as be used in Volumetric evaluation and well trajectory planning. Depth converted events are displayed below;

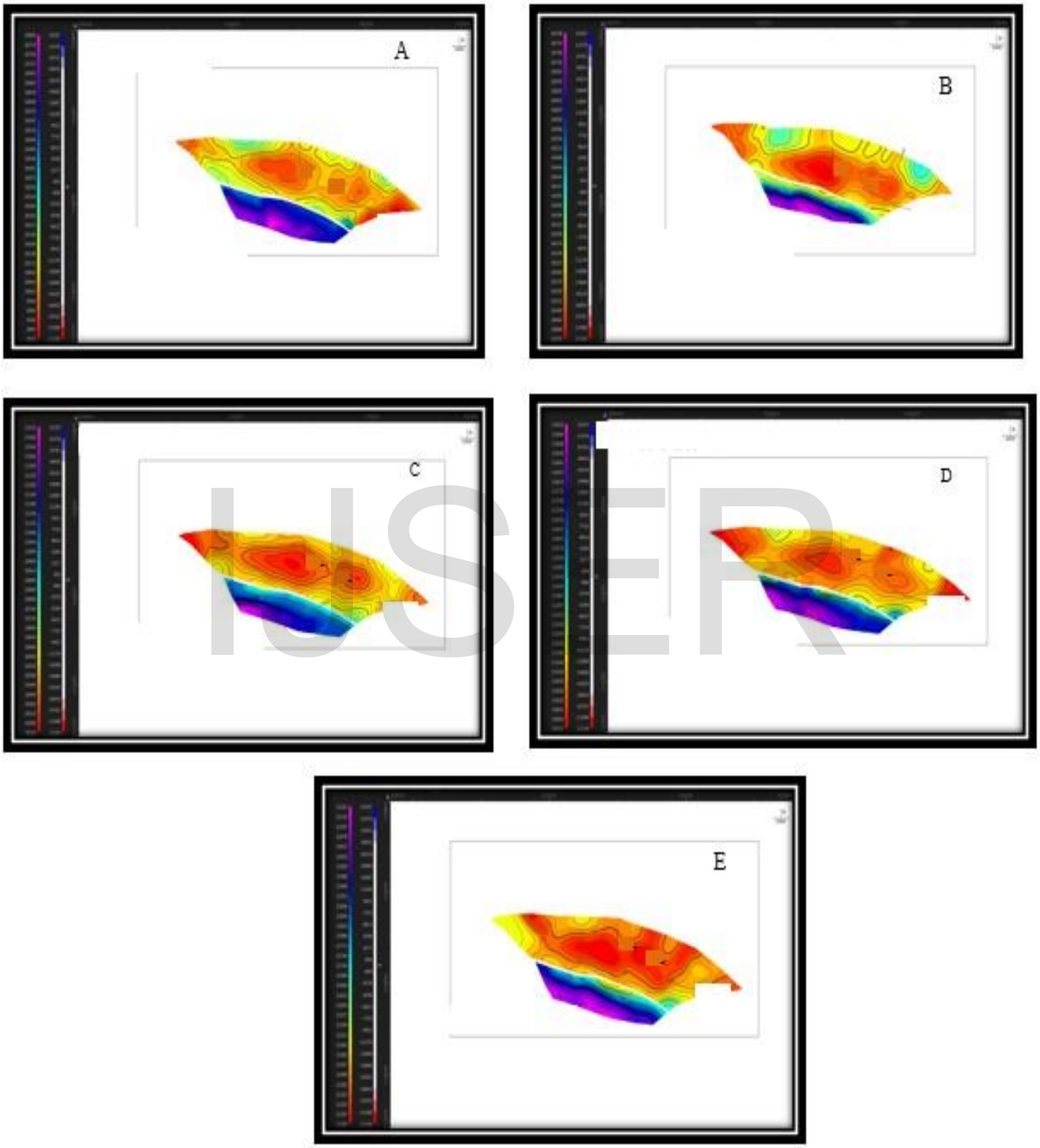

Figure 4.8. A, B, C, D and E depth maps

4.9 DEPTH UNCERTAINTY ANALYSIS

Depth uncertainty analysis is usually calculated from the average residual values from the depth converted events.

For this project, however, a more generic approach was adopted over the statistical approach to define the depth uncertainty due to paucity of data (one well penetration) in the area of interest Uncertainty range of 0.3% - 0.5% of total depth was use which is a standard approach for solving this type of challenge based on regional correlation of the Niger Delta. These values were comparable with the ranges used in other fields such as; Nata, Lyzta and Koca fields e.t.c.
However, result from depth uncertainty analysis is shown below;

Table 4.9. Depth uncertainty analysis

WELL	RESERVOIR	DEPTH (ftss)	% RELATIVE TO RESERVOIR DEPTH	APPROVED DEPTH UNCERTAINTY (ftss)
UTU 01	A	10030	0.5	+/- 50.15
UTU 01	B	10223	0.5	+/- 51.12
UTU 01	C	10463	0.5	+/- 52.32
UTU 01	D	10966	0.5	+/- 54.83
UTU 01	E	11356	0.5	+/- 56.78
AVERAGE UNCERTAINTY = 53.04 (ftss)				

Approved depth uncertainty values in the table above were given to the PG for Low and High case volume estimation.

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4.10 STRUCTRAL FRAMEWORK

This was built from depth converted faults and horizons that were tied to the well tops using Petrel. It helps Geoscientist to define reservoir geometry and architecture. The resultant watertight model was used as input to the static model. The developed structural framework building process is shown below;

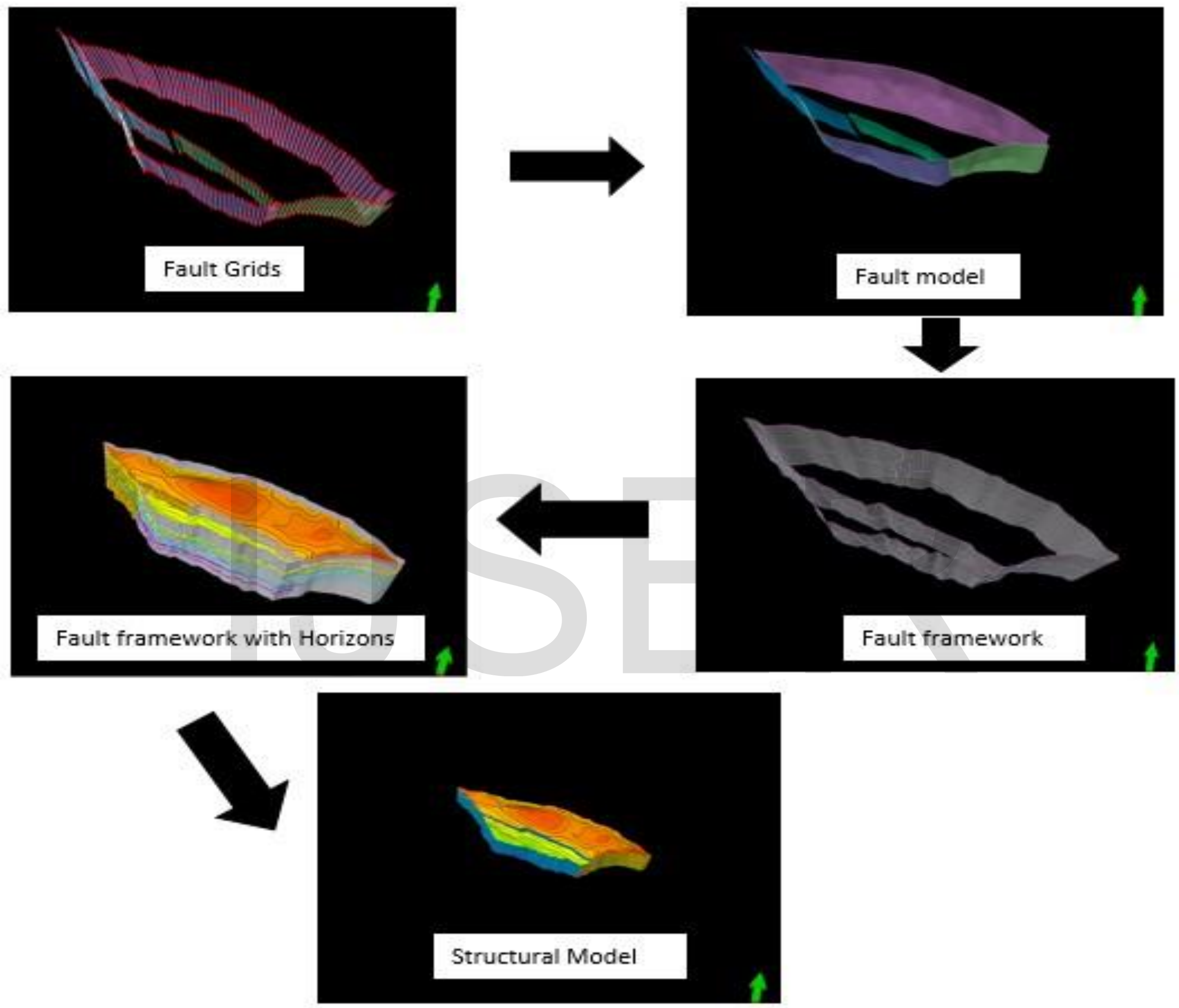

Figure 4. 9. Structural framework building process

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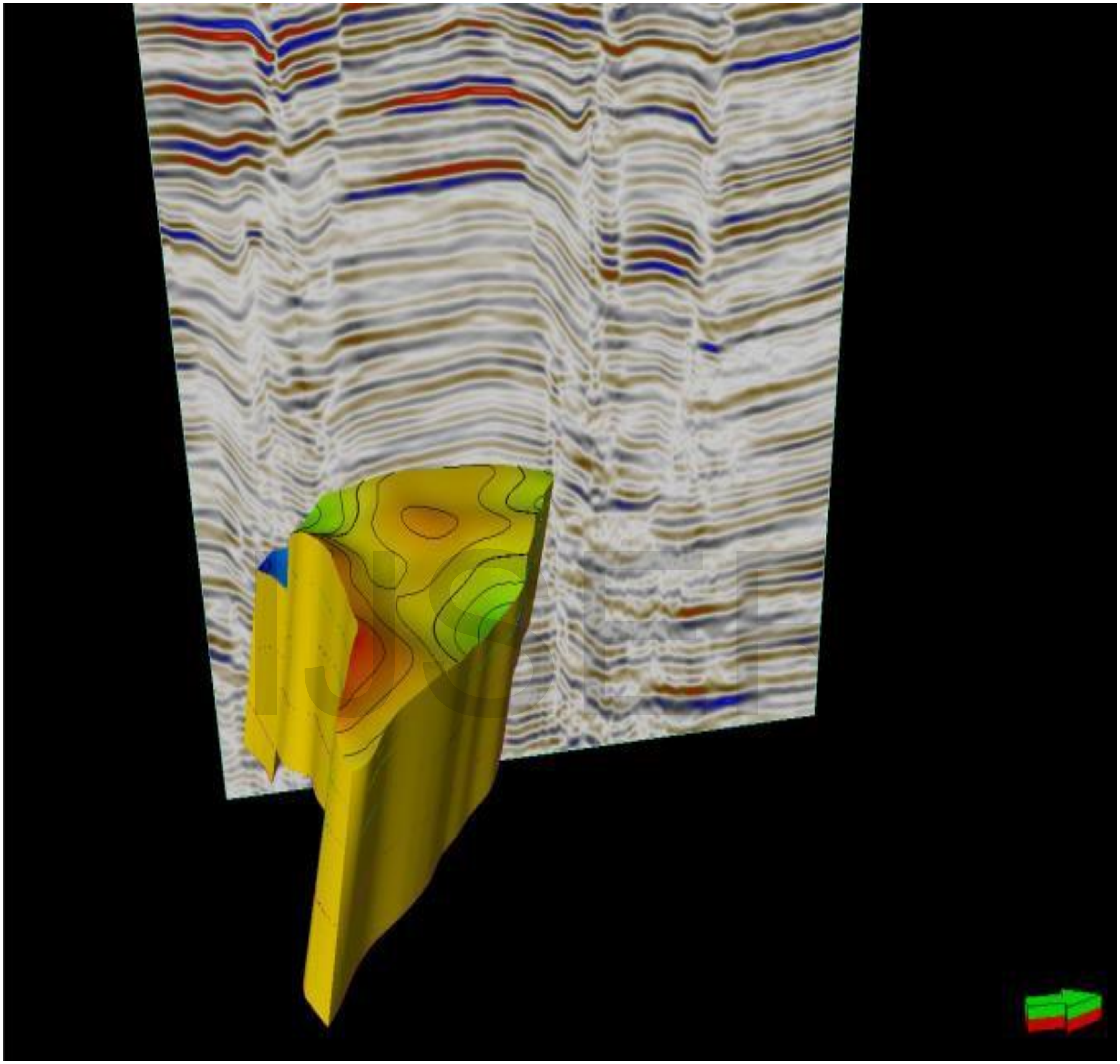

Figure 4.10. Structural framework QC process

4.11 AMPLITUDE EXTRACTION

Amplitude maps were generated from the time top structure maps to analyze the amplitude anomaly associated with the individual geology. This is to ascertain the possibility of hydrocarbon accumulation in the reservoirs of interest. Amplitude maps were extracted from Zero Line from reflectivity data using various widows. Amplitude extraction result for A, B, C, D and E reservoirs are shown below;

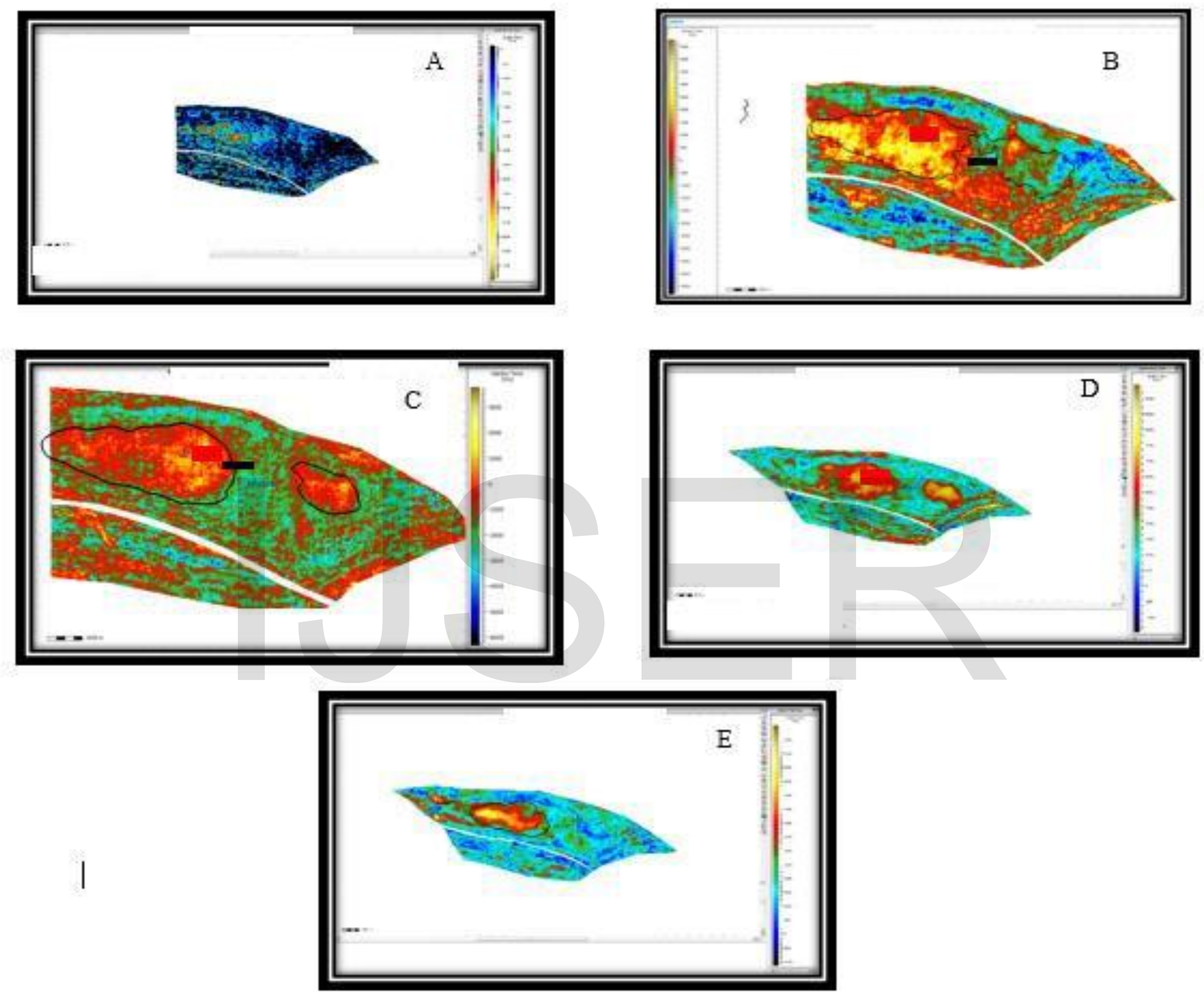

Figure 4.11. A, B, C, D and E Reservoirs amplitude maps

4. 12 INVERSION

Inversion is a backward modeling which a process of transforming seismic reflection data into quantitative estimate of rock property. As such, a rock property gives a better description of a reservoir. Hence, inversion is a non-unique solution.

A 2011 re-processed seismic was inverted to remove tuning effect and derive an acoustic impedance volume for reservoir propertied prediction. The inverted volume is shown below;

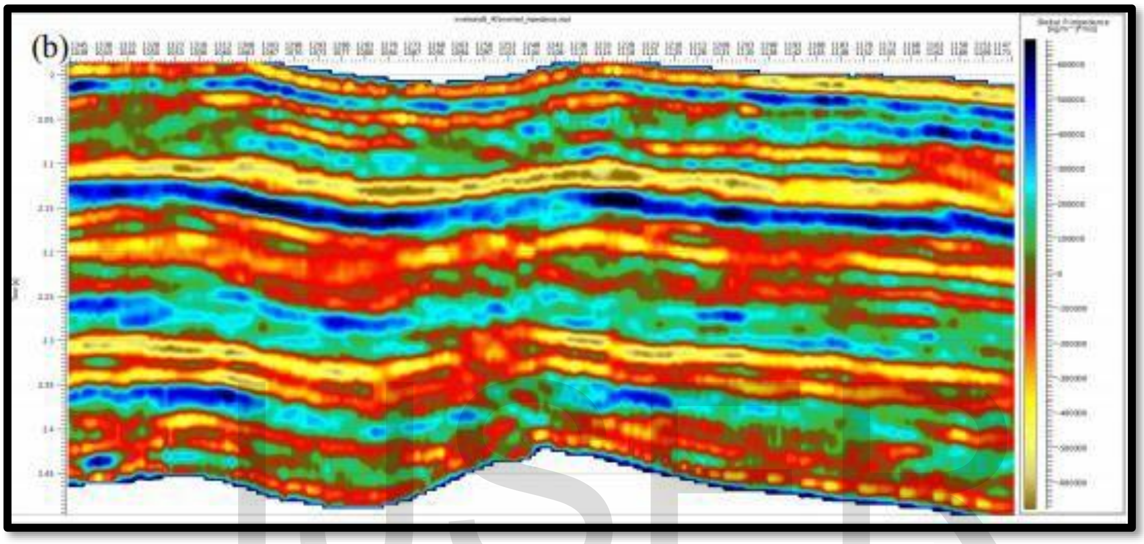

Figure 4.12a. Acoustic Impedance Volume

The resultant acoustic impedance volume was used for reservoir property prediction and for resolving lateral sand development uncertainty.

Acoustic impedance maps were generated for A, B, C, D and E reservoirs. The acoustic impedance maps generated showed that the A, B, D and E reservoirs had good sand development going from the eastern to the western part of the field. This is shown in the diagrams below;

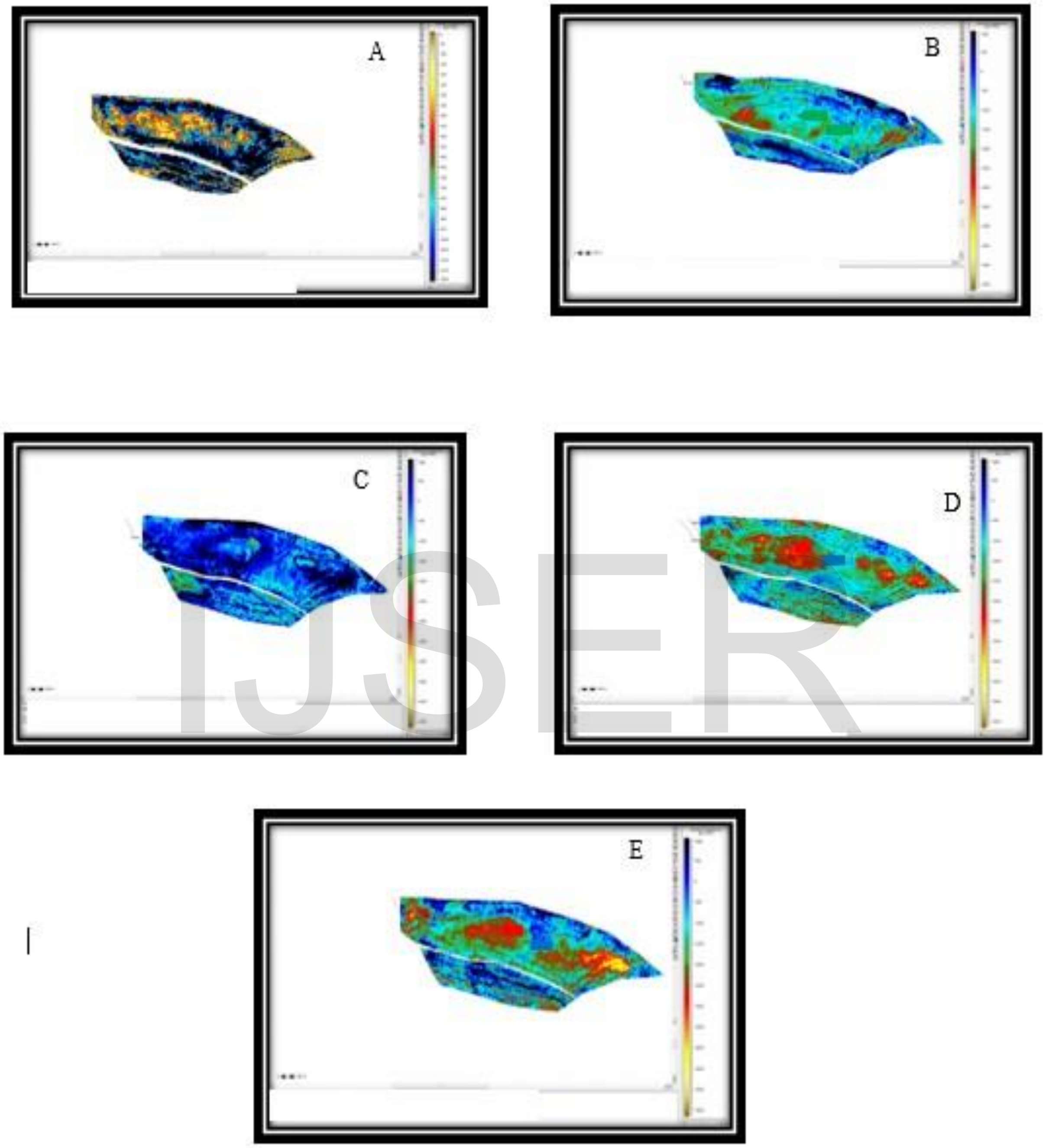

Figure 4.12b. A, B, C, D and E Acoustic Impedance Maps

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4.13 LINEAR REGRESSION AND POROSITY VOLUME

A linear regression was drawn in the depth of interest to be able to generate constant values for the straight-line equation for generation of a porosity volume since porosity has a direct relationship with acoustic impedance.

Mathematically, acoustic impedance is given by, $Z=PV$

Where Z = acoustic impedance, V= velocity and P= density

While porosity is mathematically given by,

$$\emptyset = \frac{Pma - Pb}{Pma - Pf}$$

Where ϕ = Porosity, Pma = matric density, Pb= bulk density and Pf= fluid density Respectively. The generated porosity volume and porosity maps are shown below;

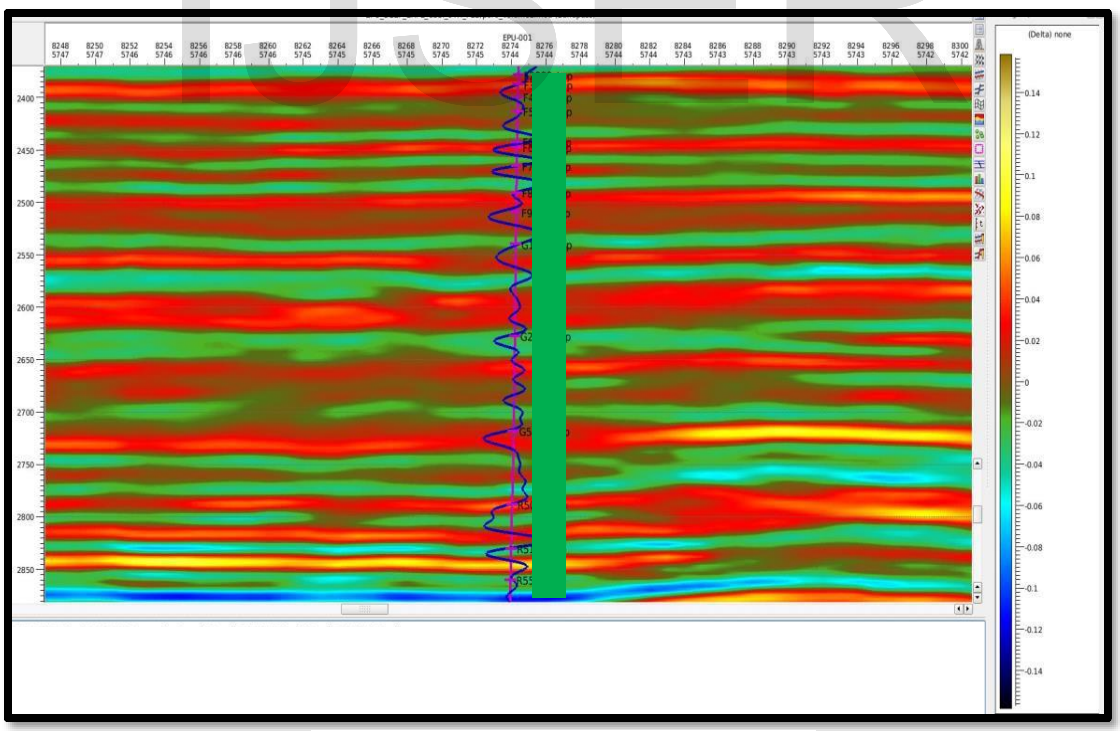

Figure 4.13a. A Porosity Volume

POROSITY MAPS

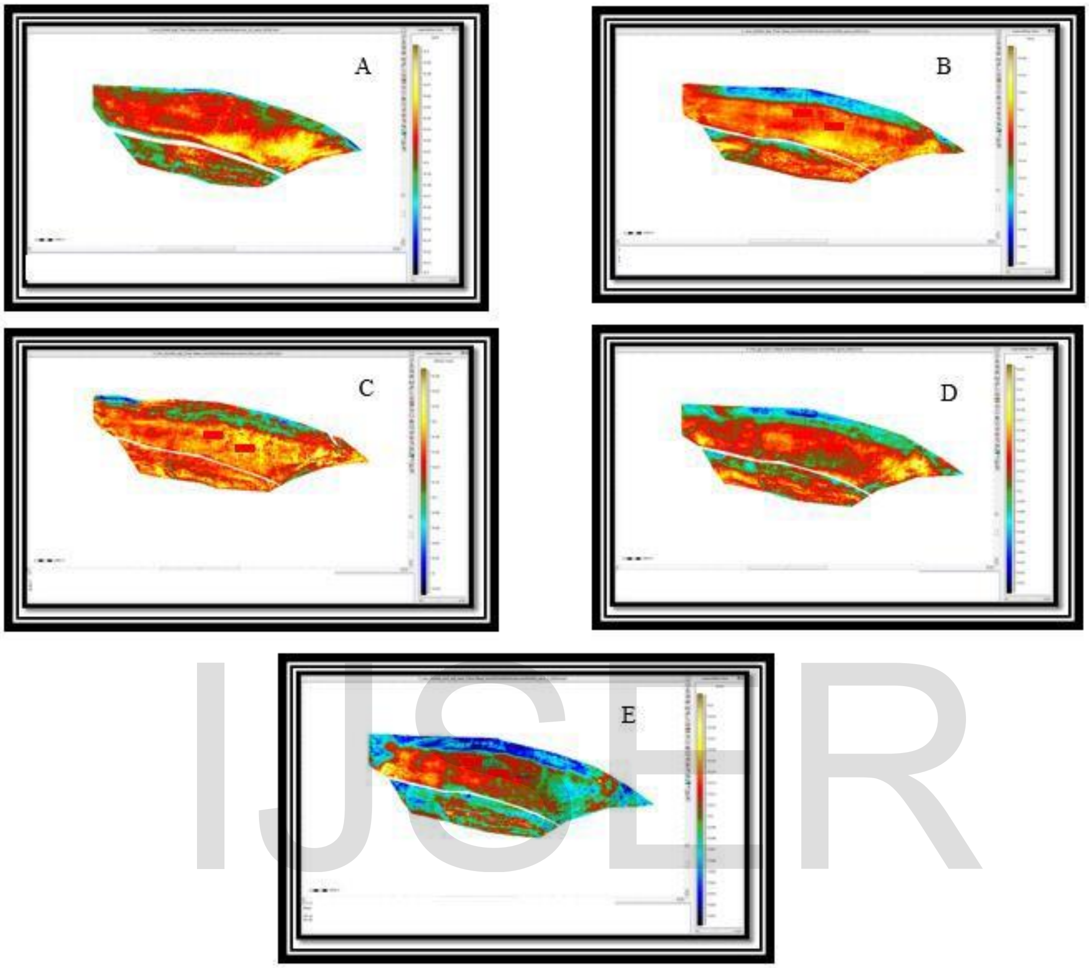

Figure 4.13b. Porosity Maps

Table 4.13. Average porosity values maps

RESERVOIR	QI POROSITY (%)	WELL POROSITY(%)
A	22	18
B	19	17
C	18	20
D	17	17
E	14	18

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The result from the average porosity measured around the well path showed a consistent decrease in porosity with depth as a result of compaction and overburden effect. This result is shown in the table above.

4.14 FLUID CONTACT ESTIMATION

Fluid contact estimation was carried out for the A, B, C, D and E reservoirs to resolve the fluid contact uncertainty issues in the mentioned sands.

A polygon was drawn at different angles on the generated amplitude maps and the depth converted events. A corresponding amplitude versus depth cross plot was generated showing amplitude contrast between the hydrocarbon and water. The fluid contact values were read off at the point where density contrast happened. This was done independently for A, B, C, D and E reservoirs. The generated values were passed on to the PG and RE for volumetric estimation. This however, served as the bedrock for the economic analysis and production forecast.

The fluid contact estimation results are shown below;

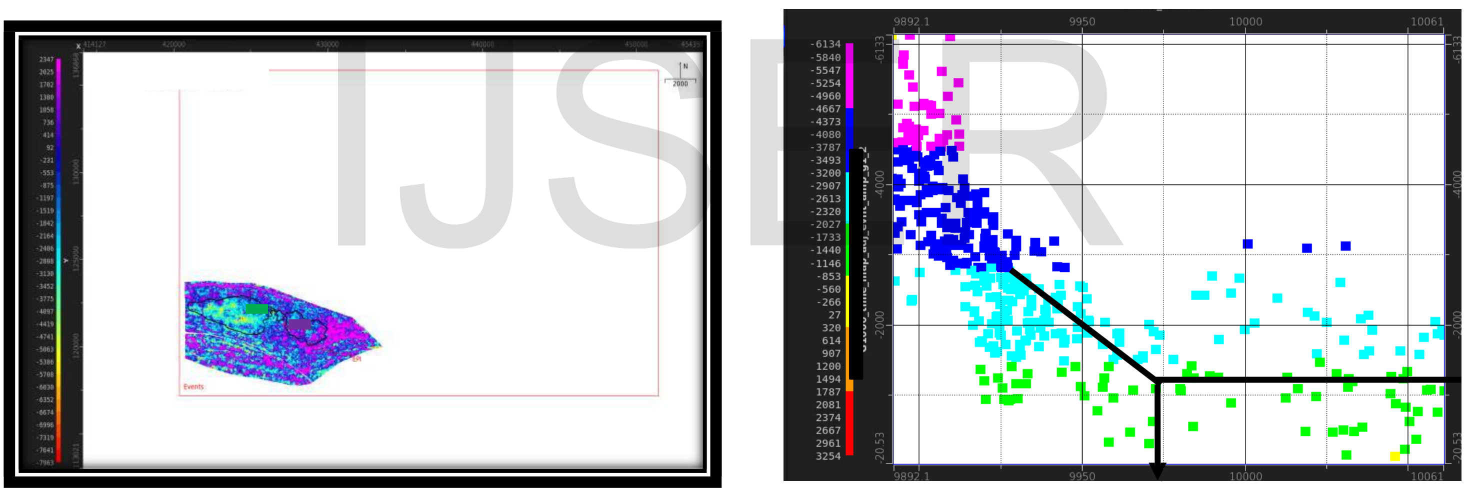

Figure 4.14a. A Reservoir fluid contact estimation

A reservoir contact values

Low case = 9957ftss

Base case = 9967ftss

High case = 9972ftss

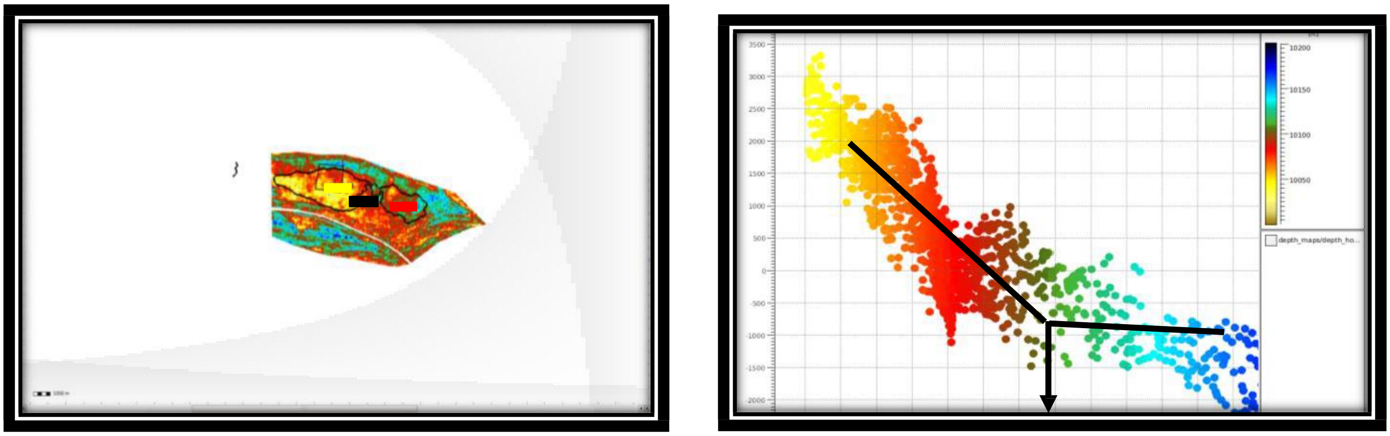

Figure 4.14b. B Reservoir fluid contact estimation

B reservoir contact values

Low case = 10132ftss
Base case = 10122ftss
High case = 10112ftss

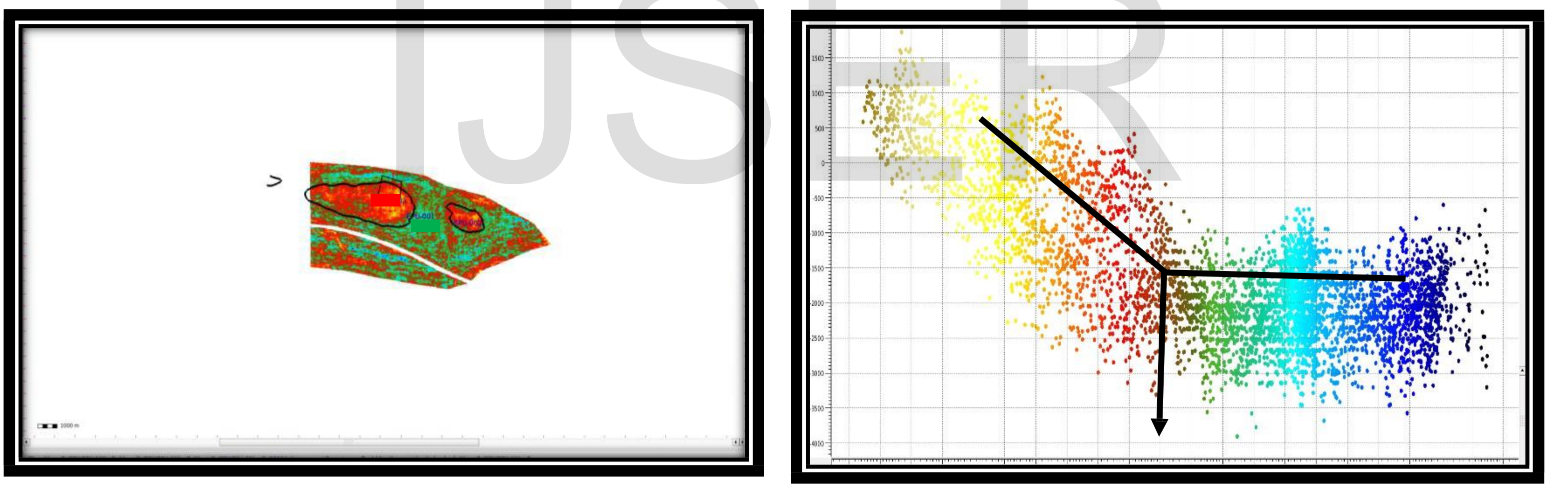

Figure 4.14c. C Reservoir fluid contact estimation

C reservoir contact values

Low Case = 10338
Base Case = 10353
High Case = 10373

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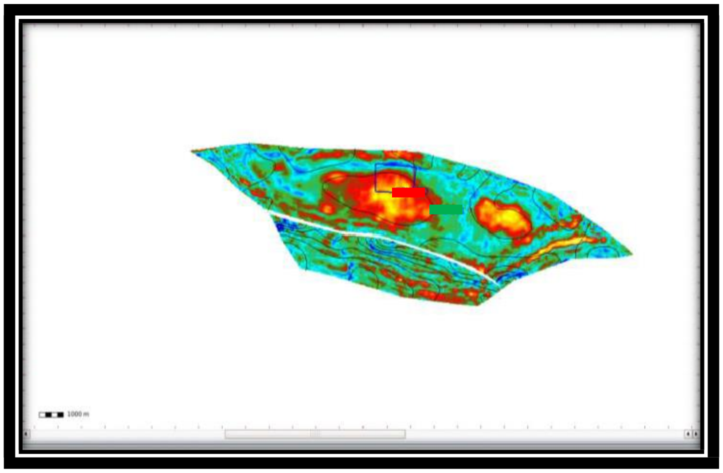


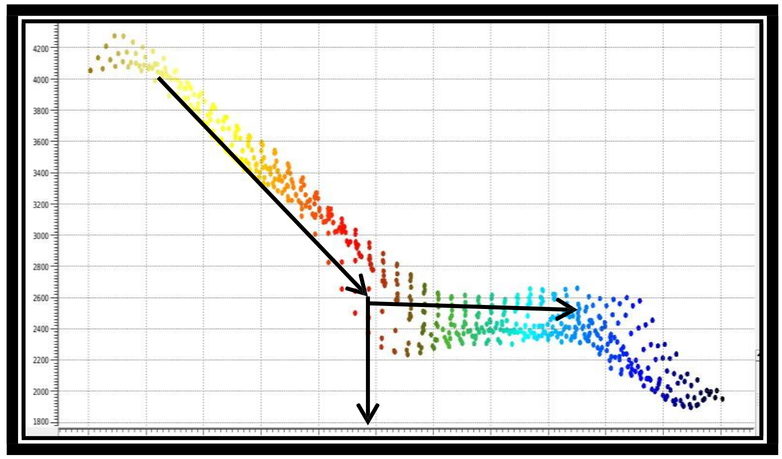
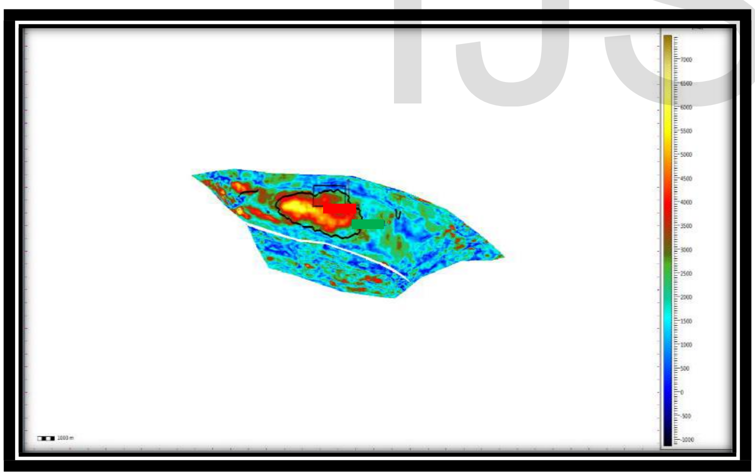
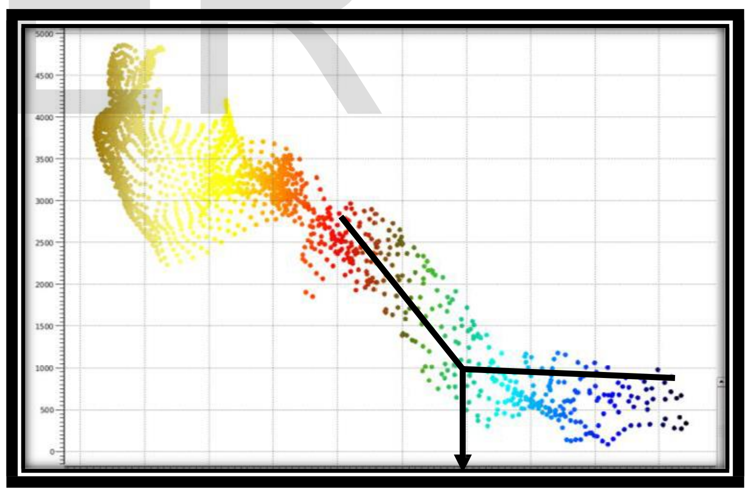


Figure 4.14d. D Reservoir fluid contact estimation

D reservoir contact values

Low case = 10879ftss
Base case = 10887ftss
High case = 10900ftss





E reservoir contact values

Low case = 11226ftss Base case = 11231ftss High case = 11256ftss

CHAPTER FIVE

CONCLUSION AND RECOMMENDATION

5.1 CONCLUSION

- The reservoir geometry for UTU A, B, C, D and E Reservoirs has been defined from detailed structural interpretation using available 3D seismic data.
- Reservoir properties and lateral sand development uncertainties has been resolved through

  QI reservoir property prediction using acoustic impedance (AI) volume.
- Fluid contacts uncertainties have been resolved from QI. Thus, providing input to volume estimations for low, base and high cases.

5.2 RECOMMENDATION

- New seismic with long cable needs to be shot for improved imaging of the area.
- The deeper plays need to be appraised for possible hydrocarbon accumulation and possible increase in resource reserve rate.
- More wells should be drilled to further validate estimated fluid contacts.

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