

CHAPTER ONE

INTRODUCTION

1.1 GENERAL STATEMENT

Over the years, the search for oil has become increasingly intense with marked technological improvement from all branches of science. In Nigeria like other countries the world all over, science and technology has made the oil industry experience a remarkably high success ratio for exploratory wells. Recently, discovery of new technology in petroleum exploration has caused enhancement of former non – economic fields. Current oil reserves are rapidly becoming depleted due to an increase in global demand for hydrocarbons as primary source of energy. This is a consequence of the fact that new petroleum plays are becoming increasingly complex, important and arduous to deal with. This state of affairs has prompted the oil industry to be very accurate, consistent and efficient to augment production from the estimated recoverable hydrocarbon reserves within minimal time.

There are several depositional basins in Nigeria, of all these, the Niger Delta Basin has proved to possess great potentials for oil and gas exploration. Exploration activities in Nigeria dates back to 1908 led by a German Company, the Nigerian Bitumen Corporation and later by Shell d’Arcy which became the precursor to Shell-BP and subsequently Renaissance Africa Energy Limited (RAEC) formally Shell Petroleum Development Company (SPDC) Nigeria. Currently, there are so many companies operating in the Niger Delta area.

Nigeria is one of the most prolific oil producing countries in Sub-Saharan Africa because of the significant hydrocarbon concentration in the Niger Delta Region. Due to its significant

hydrocarbon accumulation, the Niger Delta Basin has been the focus of ongoing geologic research, with studies commencing as early as 1956 when oil was discovered in commercial quantities in the Oloibiri-1 well. Because of the ongoing need for petroleum products and the ongoing search for hydrocarbon, researchers have consistently expressed interest in reevaluating the ageing fields within the Niger Delta (Itiowe *et al.*, 2021).

In petroleum reservoir characterization, it is crucial to understand the mineralogy and the shape of the hydrocarbon-bearing rocks which are usually sandstones or fractured limestones. The importance of petrophysical studies is based on the need to evaluate porosity from the grain size of the rock, but also permeability from the throw thickness of sands and the clays contained within the rock. This is the case in southern Africa where petrophysics are extensively used at the first stage of exploration, to predict physical properties of reservoir zones.

Since oil and gas occur in subsurface structures not exposed to easy production, the geologists with the inputs from other geo-scientists tries to construct a picture of the subsurface. Exploration and characterization of hydrocarbon reservoirs represent a multifaceted challenge that demands a holistic understanding of subsurface geology, rock properties, and fluid behavior. In the pursuit of optimal reservoir evaluation and characterization, the integration of diverse datasets becomes paramount. Among the primary sources of invaluable information are well logs, seismic data, and core data, each offering unique insights into the intricate complexities of subsurface formations.

Subsurface data interpretation is the core business of petrophysics. Petrophysical evaluation involves an in-depth examination of reservoir properties encountered during oil well drilling operations to determine potentials as viable hydrocarbon-bearing reservoirs. The goal of

such evaluation includes the detection and location of reservoir, identification of productive fluids and the estimation of recoverable hydrocarbon. A reservoir is a subsurface rock which is both porous and permeable and contains a reasonable quantity of producible hydrocarbon, if entrapment conditions are right. The amount of oil and gas contain in a unit volume of the reservoir is the product of its porosity by the hydrocarbon saturation.

The main geophysical tool with respect to reservoir characterization has been well-logging. Other tools includes, seismic reflection methods. The targets of the above mentioned tools is to investigate different revoir properties of reservoirs that exist at various depths in the earth's crust. Well logs, acquired during the drilling process, provide continuous measurements of rock properties such as lithology, porosity, permeability, and fluid saturations. These logs serve as high-resolution records of the geologic formations encountered along the wellbore, offering crucial details for understanding the vertical heterogeneity of the reservoir.

Seismic data, obtained through the controlled generation and recording of acoustic waves, contribute to a comprehensive subsurface image. Seismic surveys offer insights into the three-dimensional geometry of subsurface structures, facilitating the identification of faults, folds, and stratigraphic variations. The interpretation of seismic reflections and attributes aids in mapping the distribution of rock properties over large spatial extents.

Core data, extracted from physical samples obtained through coring operations, represent a ground truth for reservoir properties. Cores provide direct measurements of rock composition, allowing for detailed analyses of mineralogy, petrophysics, and mechanical properties. Core data are essential for calibration and validation, enhancing the reliability of interpretations derived from well logs and seismic data. The integration of these datasets transcends traditional reservoir

evaluation methodologies, fostering a synergistic approach that capitalizes on the strengths of each data type. This integrative paradigm aims to overcome the inherent limitations and uncertainties associated with individual datasets, offering a more accurate and robust reservoir characterization.

Exploration geologists have contributed immensely in increasing the world petroleum reserves through their successful exploration ventures. The geophysical tool used though individually have their acquisition limitations, can give more coherent and superb subsurface information when integrated. Objective searches for and recovery of petroleum deposits, both in commercial and non-commercial quantities has been successfully carried out by petroleum geologists.

This has led to the integration of geophysical methods especially seismic techniques into exploration works. It is on this basis that this work is carried out to enhance a subsurface configuration through integration of wireline well logs, seismic data, and core data for reservoir evaluation and characterization. In this context, this study explores the challenges and opportunities in integrating well logs, seismic data, and core data for reservoir evaluation and characterization in TOK's Field. The TOKS field comprises of several hydrocarbon bearing reservoirs with SEVEN (7) wells (TOKS-14, TOKS-15, TOKS-16, TOKS-17, TOKS-18, TOKS-19, TOKS-51).

The TOKS wells are situated in the TOK's Field of the Greater Ughelli Depobelt in the Niger Delta Basin, Southern Nigeria. The Niger Delta Basin is located on Central Africa's western coast, in the Gulf of Guinea (Lucas and Omodolor, 2018).

Exploration for hydrocarbons depends on the Niger Delta's stratigraphy and the minerals that are connected with it. The delta was first explored and exploited in 1956. The delta is a large basin that is well-known for offering source and reservoir rocks for the extraction of hydrocarbons (Itiowe *et al.*, 2021).

1.2 STATEMENT OF PROBLEM

Previous studies on reservoir characterization and evaluation have always been done using well logs and seismic data which does not give clear reflection of the hydrocarbon prospect and potentiality of these fields, thus the need for this study which intends to integrate seismic data, core, well logs, semblance map cube for a detailed reservoir characterization and evaluation of Tok's field, hence bridging the existing knowledge gap of the previous studies.

1.3 AIM AND OBJECTIVES

AIM

This research is aimed at reservoir characterization and evaluation of Toks field, Greater Ughelli Depobelt, Niger Delta, Nigeria.

OBJECTIVES

The following research objectives are to;

- i. identify the reservoirs sections thickness in the wells of the field and pay nzone within them.
- ii. determine the facies types and layering in the wells section of the field.

- iii. review and critically assess existing reservoir evaluation in terms of its strengths, weaknesses, and limitations of conventional approaches.
- iv. investigate the geological and geophysical principles underlying well logs, seismic data, and core data by exploring the fundamental principles governing well logging, seismic interpretation, and core analysis and establishing a theoretical foundation for the integration of these diverse datasets.
- v. develop a methodology for integrating Well Logs, Seismic Data, and Core Data by designing an integrated workflow for combining well logs, seismic data, and core data developing algorithms or models to correlate and reconcile the datasets.
- vi. implement the integration of methodology in petrel software by utilizing petrel software for importing, visualizing, and integrating well logs, seismic data, and core data as well as optimizing and adapting Petrel tools for seamless dataset integration.

1.4 SCOPE OF STUDY

The scope of this study covers a multidisciplinary approach which intends to integrate seismic data, cores, well logs, semblance map cube for a detailed reservoir characterization and evaluation of TOK's field.

1.5 SOURCE OF DATA

Renaissance Africa Energy Limited (RAEC) formally Shell Petroleum Development Company (SPDC) Nigeria provided the data used in this evaluation and this includes Segy three

dimension (3D) seismic, well header, ASCII/Excel well deviation, ASCII well logs and checkshot.

1.6 LOCATION OF WELL

Nigeria's Niger Delta Basin is home to the TOK's Field. The Niger Delta sedimentary basin is located in the southern part of Nigeria, bordering the Atlantic Ocean between latitudes 4° and 6°N, and longitudes 3° and 9°E (Fig 1.1 1.3). It is bounded in the south by the Gulf of Guinea and in the north by the Anambra Basin, Afikpo uplift and Afikpo syncline. The Delta covers an area in excess of 105,000km² and extends in an east-west direction from Cameroun to the Okitipupa ridge.

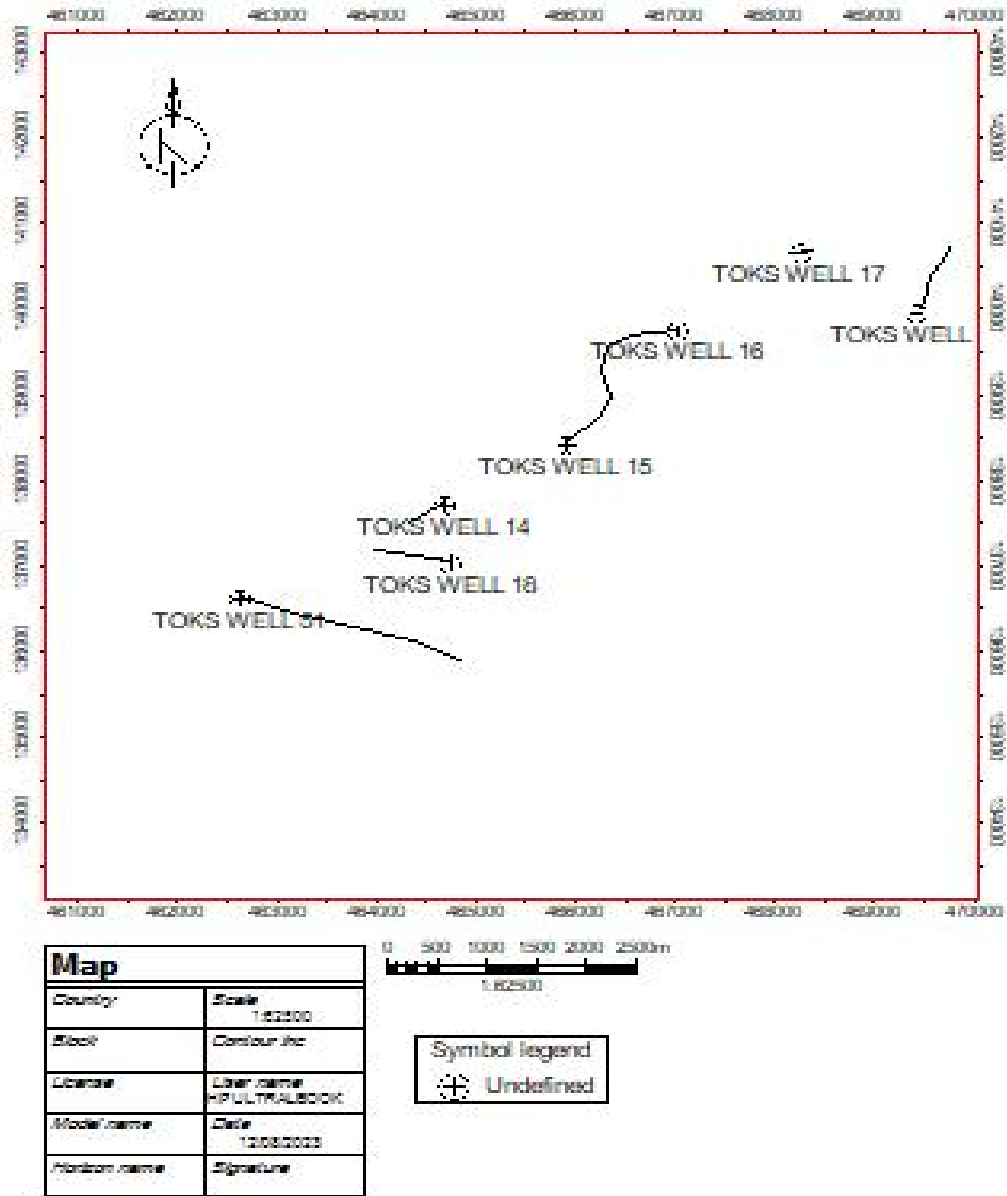


Fig.1.1: The Base map of the 7 wells location in the study area

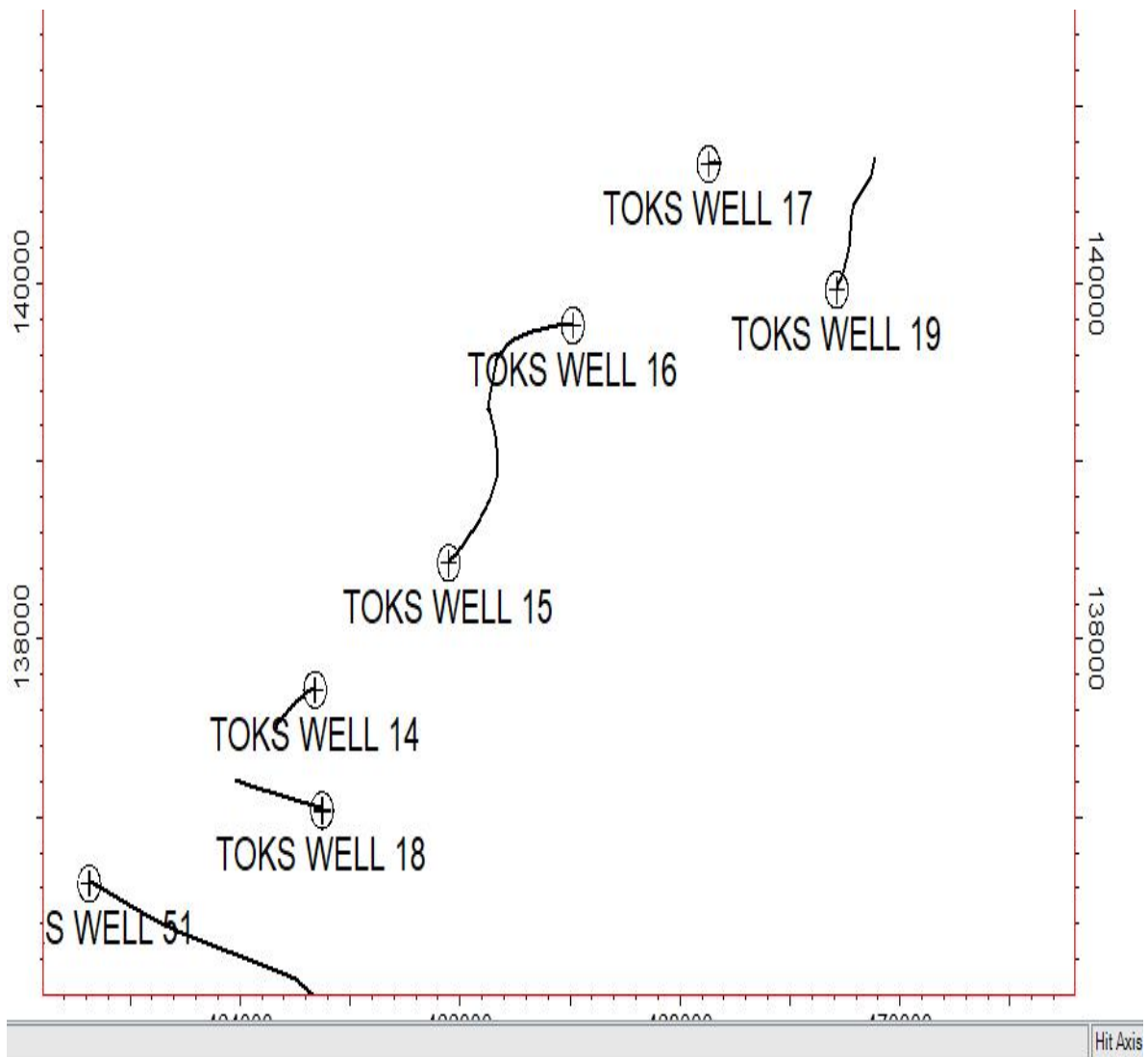


Fig.1.2: Map of the spatial distribution of the 7 wells location in the study area

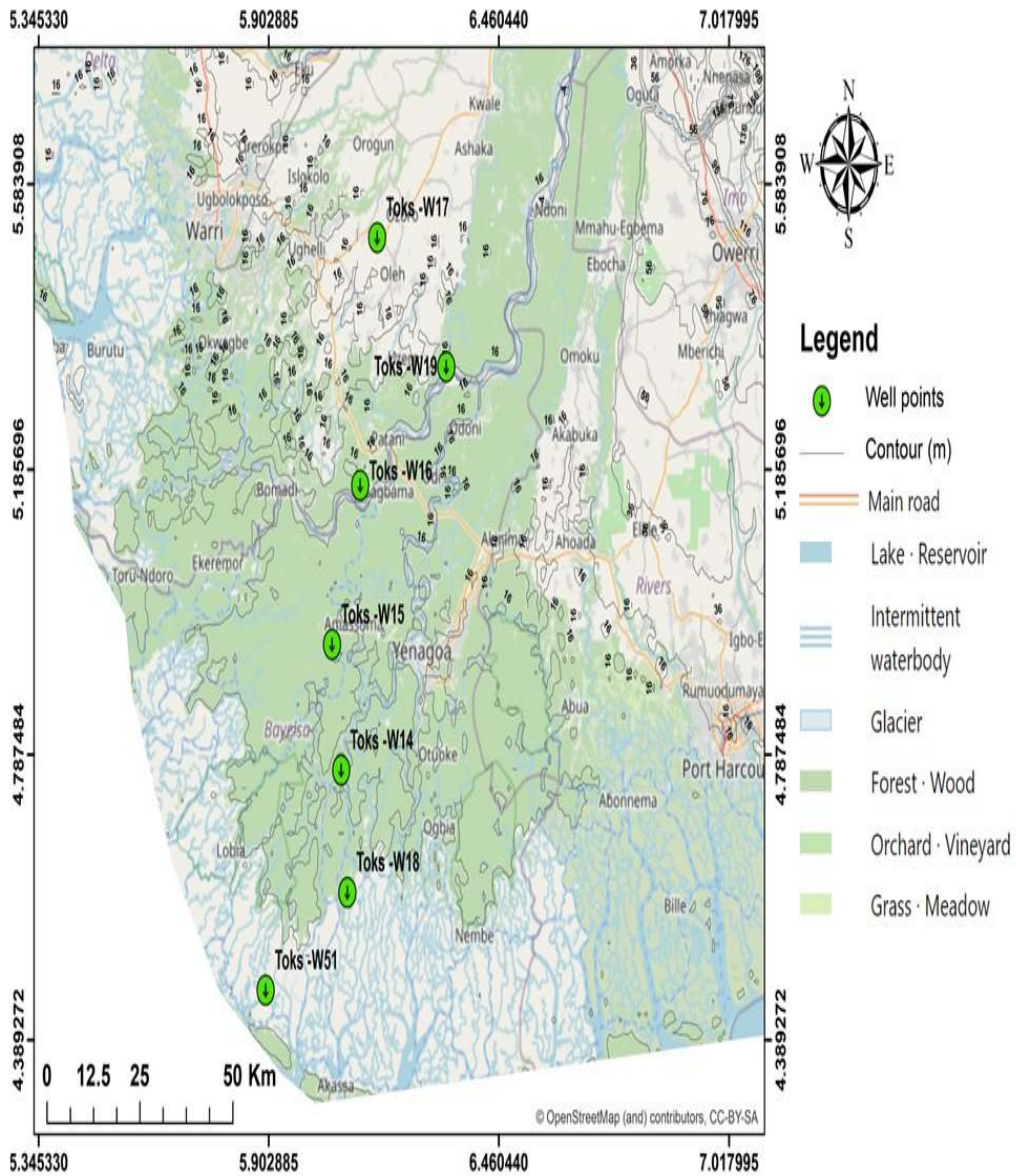


Fig.1.3: Location Map of Study Area

1.7 SIGNIFICANCE OF WELLOGS IN PETROLEUM STUDIES

Reservoir characterization plays a critical role in various aspects of petroleum studies, contributing significantly to successful exploration, development, and production of hydrocarbons. Here's a detailed breakdown of its significance:

i. Identifying Potential Reservoirs

The knowledge is crucial for pinpointing potential source and reservoir rocks, as these processes influence the presence and characteristics of hydrocarbons (Selley, 2012). It allows petrophysicists to identify areas with favorable reservoir characteristics (Amsden, 1960).

ii. Understanding Reservoir Quality

Characterizing porosity, permeability, and pore connectivity: These properties control the flow and storage of hydrocarbons within the reservoir and helps to predict these crucial characteristics (Schlumberger, 2014).

iii. Predicting Reservoir Behavior

Understanding depositional environment and influencing factors: This knowledge allows for predictions about the internal architecture and heterogeneity of the reservoir, impacting fluid flow and recovery (Walker, 2010).

Vital information for reservoir modeling and simulation: These techniques rely on accurate characterization of the reservoir, which is facilitated by sedimentological data (Lake, 2014).

iv. Exploration and Appraisal

Integration with other geological data: Sedimentological data, alongside seismic, well log, and geochemical information, helps assess potential hydrocarbon prospects during exploration activities (Glennie, 1995).

Selection of drilling locations, prediction of reservoir thickness and continuity, and resource volume evaluation: These critical decisions rely heavily on the insights provided by Sedimentological studies (Halbouty, 1970).

v. Reservoir Management

Optimizing production strategies and maximizing recovery: Understanding reservoir heterogeneity and fluid flow characteristics, allows for efficient production planning and implementation of enhanced recovery techniques (SPE, 2013).

In conclusion, reservoir evaluation serves as an important role in petroleum studies, offering invaluable insights into the formation, quality, and behavior of hydrocarbon reservoirs. By leveraging this knowledge, petroleum professionals can navigate exploration, development, and production stages with greater efficiency and success.

1.8 SIGNIFICANCE OF SEISMIC DATA IN PETROLEUM STUDIES

i. Age Determination and Correlation

Dating rock units: Biostratigraphy allows geologists to determine the relative and absolute ages of rock formations by analyzing the presence and absence of specific fossil assemblages

(Haq and Van Eeden, 1998). This age information is crucial for understanding the geological history of a basin and identifying potential source rocks and reservoir units.

Correlating rock layers across vast distances: By identifying marker fossils with known age ranges, biostratigraphy's can correlate rock layers even in geographically separated areas, facilitating basin reconstruction and exploration efforts (Benton, 2005).

ii. Palaeoenvironmental Reconstruction

Understanding depositional environments: Different fossil assemblages are indicative of specific environments, such as marine, terrestrial, or lacustrine. Biostratigraphic analysis helps reconstruct the paleo environments in which sedimentary rocks were deposited, providing valuable insights into the potential presence and quality of hydrocarbon reservoirs (Riding, 2002).

iii. Hydrocarbon Exploration and Production

Identifying source rocks and reservoir seals: Organic-rich shales containing specific types of fossils often indicate potential source rocks for hydrocarbons. Similarly, certain fossil assemblages can help identify impermeable rock layers that act as effective reservoir seals (Schlumberger, 2014).

iv. Wellsite biostratigraphy

Real-time analysis of fossils from drill cuttings allows for accurate depth determination, assisting in decisions like setting casing points and optimizing drilling strategies (Davies, 2016).

v. Reservoir Characterization and Management

Understanding reservoir continuity and heterogeneity: Biostratigraphic data can help identify variations in depositional environments within a reservoir, impacting reservoir properties like porosity and permeability (Carney, 1986). This information is crucial for reservoir characterization and efficient production management.

In conclusion, biostratigraphy offers a valuable tool for petroleum geologists and engineers by providing insights into the age, environment, and characteristics of rock formations. This knowledge significantly impacts exploration success, reservoir characterization, and efficient production strategies.

1.9 SIGNIFICANCE OF SEMBLANCE MAPS IN PETROLEUM STUDIES

They reveal discontinuities by measuring trace-to-trace similarities, making discontinuities such as faults and channels appear as low-coherence zones. They reveal stratigraphic features by imaging lateral changes in seismic response caused by variations in stratigraphy, lithology and porosity which can be indicative of hydrocarbon reservoirs. They reveal fluvial systems used in detecting sands associated with these deposits. They are used for structural analysis in mapping and interpreting fault planes other structural complexities within a petroleum province. They are used for seismic facies analysis for analyzing the continuity and configuration of seismic reflectors, semblance maps contribute to defining seismic facies that are linked to specific stratigraphic bodies and lithologies. They are used for play and prospect evaluation to provide detailed information that helps in the understanding of the architectural styles of geological plays and predicting potential reservoir rocks for exploration. They are used for integration with other data like well logs, stratigraphic data and paleobathymetric data to build comprehensive geological and seismic facies models for a field.

Basically, it is of immense benefits in minimizing and reducing drilling risks, enhance confidence in improved interpretations by allowing for more accurate correlation of seismic features with geological structures and stratigraphic units, as well as assist in identifying potential hydrocarbon accumulation targets, guide exploration efforts towards more promising areas.

1.10 ROLE OF IMAGING IN RESERVOIR CHARACTERIZATION PROCESS

Imaging techniques are essential tools in reservoir characterization as they enable geoscientists to visualize and understand subsurface structures and properties. These techniques provide crucial data for identifying potential hydrocarbon reserves, delineating reservoir boundaries and assessing reservoir quality. Seismic imaging technique utilizes seismic waves to create detailed images of the subsurface. By analyzing seismic data, geoscientists can map structural features and estimate rock properties such as porosity and fluid content. The gathered information aid in making informed decisions about drilling locations and optimizing production strategies. Electromagnetic imaging measures electromagnetic fields to detect variations in electrical properties, giving insights into hydrocarbon presence, lithology and fluid distribution.

It

is particularly useful in unconventional reservoirs where traditional seismic methods may be limited. Resistivity imaging is a technique that measures subsurface resistivity variations, geoscientists can infer lithology changes, fluid saturations and permeability distributions within the reservoir. The information gathered is vital for understanding fluid flow patterns and maximizing hydrocarbon recovery. X-ray computed tomography (CT) scanning is employed to

capture 3D images of core samples. This non-destructive technique allows geoscientists to study the internal structure, porosity and fluid flow pathways.

1.11 DEFINITION OF TERMS

a. RESERVOIR CHARACTERIZATION

This is the process of obtaining detailed information about a subsurface reservoir, including its size, shape, location and fluid content. This involves combining multiple sources of data, such as seismic surveys, well logs and geological studies, to develop an accurate understanding of the reservoirs geology and potential production capabilities. Characterizing a reservoir accurately is crucial for optimizing production and maximizing recovery and minimizing costs. It is a critical aspects of the oil and gas exploration process, playing a fundamental role in understanding the properties and behavior of subsurface reservoirs. It involves the comprehensive assessment and description of various geological and engineering aspects to optimize hydrocarbon recovery. By combining geological interpretation, geostatistics, rock physics and fluid flow models, reservoir characterization provides valuable insights into the distribution, heterogeneity and potential productivity of reservoirs.

The main objective of reservoir characterization is to understand key lithology-related properties that are relevant for understanding reservoir conditions. This dynamic process requires continuous updating as new data becomes available throughout the lifespan of the reservoir. To achieve comprehensive reservoir characterization, a multi-disciplinary approach is typically employed. This involves integrating geological, petrophysical, geophysical and engineering data to develop accurate models that capture the complexities and uncertainties of the subsurface environment.

b. WELL LOGS

These are graphical record of measurements taken from a borehole with depth plotted against the measured property. It provides crucial information about the subsurface geological formations, including their thickness, type and properties. They are created using logging tools (instruments) that are lowered into a borehole to measure various physical properties of the surrounding formations including their thickness, type and properties. They are also created by plotting measurements against depth to create the log which can be a physical record or digital data. They measures key properties like resistivity (which is the ability of a rock formation to resist the flow of electric current, used to detect hydrocarbons and differentiate rock types), gamma ray (which measures the natural radioactivity of a formation with low gamma ray values often indicating a potential reservoir rock like sandstone), spontaneous potential (which measures naturally occurring voltage differences to help identify formation types and distinguish between permeable and impermeable layers) and porosity (which are determined by measurements like density, neutron density, and acoustic logs that indicates the amounts of open space within the rock, crucial for strong fluids like oil or water. They are applied in geological and geophysical analysis (for subsurface mapping and geophysicists use them to compliment surface seismic data), petroleum industry (for locating and characterizing hydrocarbon (oil and gas) reservoirs, calculating hydrocarbon volumes and evaluating reservoir performance and water resource management (for documenting the wells construction, the types of aquifers encountered, water levels and water quality).

c. CORE DATA

These are cylindrical sections of rock drilled from the Earth's subsurface. They are subjected to detailed examination, described and logged to record various geological properties. Cores aids in the collection of lithological and mineralogical data (which is the descriptions of the rock types and abundance of minerals present, stratigraphic data (which are information about the arrangement and layering of rock formations), structural data (which are the identification of features like faults, fractures and folds), paleontological data (records of any fossil remains found within the core), reservoir properties (data on porosity i.e space within the rock) and permeability (how easily fluids can flow through it), which are crucial for resource exploration. They are applied and important for resource exploration (identifying potential reservoirs for oil, gas and other minerals), hazard assessment (assessing risks from geological hazards like earthquakes and tsunamis), earth history and climate studies (understanding ancient lake systems, past climate events and long-term earth processes), reservoir characterization (providing precise measurements of reservoir properties to reduce uncertainty and define rock types), calibration (calibrating and validating data from other sources, such as geophysical well logs and seismic data, against the physical core data) and for research (samples are revisited and re-analyzed to investigate energy resources such as offshore wind or inform decision on offshore subsurface storage projects. They are collected by whole coring (a hollow drill pipe with a special bit is used to cut and retrieve long, continuous sections of rock or sediment) and also by sidewall coring (smaller, individual samples are taken from the walls of a borehole using specialized wireline tools).

d. SEMBLANCE MAP

Semblance maps are generated from 3D seismic volumes by comparing the similarity of seismic waveforms in a localized window. High semblance values indicate continuous coherent seismic reflectors, while low semblance values highlights discontinuities such as faults or changes in lithology such as sand pinch-outs. They ensures the visualization of subsurface structures like faults (that appear as distinct edges or boundaries on a semblance map, showing the disruption in seismic continuity) and stratigraphic features (abandoned channels, meander belts and other stratigraphic features are clearly depicted, revealing depositional environments).

They are applied for reservoir characterization (identifying reservoir geometry and heterogeneity), prospect identification (revealing stratigraphic and structural details for identifying new exploration targets) and understanding depositional systems (visualizing depositional macroforms like deltaic sediments). The major characteristics includes attribute maps (semblance maps are a type of seismic attribute map, using different mathematical transformations of seismic data to enhance specific geological information), interpreting depositional environments (by identifying specific geometrical patterns, these maps aid in predicting the depositional history of an area) and for correlating with lithofacies (the patterns on semblance map correlated with lithofacies variations, providing insights into the distribution of different rock types).

e. BASIN

A large depressional area in the Earth's crust that accumulates sediments and sedimentary rocks over time. Basins can be formed by various processes, including tectonic activity (plate movement) and subsidence (sinking of the ground).

They are large depressions or trough in the earth's crustal with continent here sediments are deposits, transported and accumulated and eventually forming thick layers of sedimentary rock. The formation of the basin is directly linked to plate tectonics with major types arising from plate collision (convergent plate boundaries) or plates moving apart (divergent plate boundaries or rifting). A critical factor for basin formation is a topographic low, accommodation space that allows for sediment accumulation. They are classified by their tectonic setting and origin and includes; rift basins (formed when tectonic plates pull apart, creating a large extensional force that leads to faulting and subsidence), intracratonic basins (found within a continental plate, often due to stresses generated by distant plate interactions), basins at continental margins (these basins forms at the edges of continental plates and can be influenced by rifting or other tectonic processes) and basins related to plate collisions (formed at convergent plate boundaries, such as subduction zones, leading to features like foreland basins).

They are significant for petroleum systems (many basins contains source rocs which under the right conditions of burial, pressure and temperature can generate and trap hydrocarbons like oil and natural gas), paleoclimate and paleontology indices (the sedimentary rocks within a basin can provide valuable information about the past climates and ancient life of a region) and resource exploration (beyond hydrocarbons, basins can also be sources of minerals, coal and water resources). Sedimentary basins are large-scale tectonically-formed depression in the earth's crust where sediments accumulate over time to form thick deposits of sedimentary rock. These basins are crucial as they hold significant mineral and organic resources like coal, oil and natural gas, and they provide a record of the earth's geological and environmental history. Their formation is driven by plate tectonics, leading to processes like lithospheric stretching, thermal

subsidence and flexural loading which create the necessary accommodation space for sedimentation.

Nigeria has several major sedimentary basins and these includes the Niger Delta Basin (the largest and most explored basin in Nigeria is in-filled with Tertiary and Quaternary sediments and is a significant producer of hydrocarbons), Dahomey Basin (located in the western part of southern Nigeria, is part of the larger Southern Nigeria Basin), Benue Trough (an extensive inland basin divided into the Upper Benue Trough (with the arms like the Gongola and Yola arms) and the Lower Benue Trough. It extends into the Anambra Basin in the west), Sokoto Basin or Sokoto-Rima Basin (located in northwestern Nigeria and is a northward extension of the illumedian Basin) Chad Basin or Hadejia-Chad Basin (in the northeastern part of Nigeria is part of the larger Chad Basin dominated by the Tertiary and Quaternary clays and sands), Anambra Basin (situated within the Benue Trough system is known for economic potential due to its hydrocarbon and other mineral deposits) and Cross River Basin (An important coastal and inland basin in southeastern Nigeria).

f. HYDROCARBON PLAY ELEMENTS

Hydrocarbon play elements refer to the essential components required for the formation and accumulation of hydrocarbons (oil and gas) in a sedimentary basin. These elements typically include:

Source Rock

Source rock is a rock unit rich in organic matter that can generate hydrocarbons upon exposure to specific temperature and pressure conditions (Tissot and Welte, 2013).

Reservoir Rock

A reservoir rock is a porous and permeable rock unit capable of storing and allowing the flow of hydrocarbons (Selley and Sonnenberg, 2012).

Seal Rock

A seal rock is an impermeable rock unit that prevents the upward migration of hydrocarbons, trapping them within the reservoir rock (Gluyas and Swarbrick, 2004).

Trap

A trap is a geological structure or stratigraphic feature that provides a confined space for the accumulation of hydrocarbons (Hyne, 2001).

Migration Pathway

A migration pathway is a permeable route through which hydrocarbons can migrate from the source rock to the reservoir rock (Bjørlykke, 2010).

These play elements work together to create a favorable environment for the formation, migration, and entrapment of hydrocarbons, making it an economically viable hydrocarbon play (Allen and Allen, 2013).

g. SURFACE ATTRIBUTES

Surface attribute is a consideration by geoscientists as key tool for reservoir quality control and characterization, because it reveals the seismic features and anomalies, patterns and relationships. It is divided into two objective, the geometric attribute for visibility enhancement

of seismic characteristics and the physical attributes related to lithology (Othman *et al.*, 2017). There are several surface attributes (RMS), maximum amplitude, average energy).

h. SEISMIC INVERSION

Geophysicists utilizes seismic inversion to construct subsurface rock characteristics models utilizing seismic well log data. It enhances the resolution of the original or conventional seismic data. It is separated into two (2) techniques; Pre-Stacking (simultaneous and elastic inversion methods) and post-stacking inversion (Veecken *et al.*, 2004) (coloured inversion, model based inversion, sparse spike inversion and Band – limited impedance inversion methods).

i. POST – STACK INVERSION

This is an approach that employs a seismic trace (initial model) wavelet related with reflectivity plus noise. It was used to improve seismic data resolution and interpretability by eliminating incoherent noise (Farfour *et al.*, 2015). This method is extensively used in the oil and gas sector to get layer attributes for stratigraphic interpretation (Maurya *et al.*, 2016, Verkeen and Da Silva, 2004). The acoustic impedance is the multiplication of bulk density and sonic velocity, which help to predict the rock properties of subsurface such as lithology, porosity and fluid content.

1.12 THEORY OF FORMATION EVALUATION

In petrophysical studies, a formation refers to a stratigraphic unit of rocks generally deposited in the same environment, consisting of sedimentary strata usually of internal lithologic homogeneity and distinguish characteristics, in term of chemical composition and favorable physical properties (porosity and permeability) capable of bearing hydrocarbon in commercial

quantity. Nowadays, formation evaluation commonly known as reservoir characterization involves various techniques of analyzing and determining physical properties of the petroleum reservoir. Modern advances in seismic acquisition, processing and interpretation with powerful computer modelling software have significantly increased oil discovery and production.

Well Logs

A well log is the recording of the measurement of a geophysical parameter plotted continuously against depth in the well bore (Rider, 1996). It is used to identify and correlate underground rocks, determine their lithology, generate their physical properties and the nature of the fluids they contain. Geological sampling during drilling (cutting sampling) leaves a very imprecise record of the formations encountered. Likewise, entire formation samples can be brought to the surface by mechanical coring, but this is both slow and expensive (Rider, 1996). Even though geophysical logs needs interpretation to bring it to the precision and ability to bridge the gap between well cuttings and core samples.

Many different modern geophysical well logs exist. The most popular among those other are wireline geophysical well logs. They are made using highly specialized equipment entirely separate from that used for drilling. They can be run as ‘open – hole logs’ immediately after drilling and before casing, or as MWD (Measurement While Drilling) and LWD (Logging While Drilling) logs, simultaneously as the formation is drilled. Necessary geophysical measurements are obtained to allow a quantitative evaluation of hydrocarbon in place. Therefore, it is imperative to get accurate, well calibrated and complete data.

1.12.1 WELL LOG EVALUATION THEORY

Well log analysis is the process of using borehole measurements call logs to evaluate the characteristics of the subsurface. It involves the determination of various petrophysical parameters of rock formations and strata encountered during oil well drilling operations, and the fluids contained in the subsurface. These properties are then computed using either the standard charts or the simple calculations to determine basic reservoir and fluid properties in the subsurface. The main petrophysical parameters needed to evaluate a reservoir are its, porosity, hydrocarbon saturation, thickness, area and permeability. In addition, the reservoir geometry, formation temperature and pressure, and lithology can play important roles in the evaluation, completion and production of a reservoir.

Well log data are used to correlate zones, identify productive zones, to distinguish between oil and gas or water in a revoir and to estimate hydrocarbon reserves and help to determine facies relationship during drilling. Well data has in the past has been acquired through wireline conveyed tools i.e logging tools lowered in the borehole on 7 – conductor cable over which power, operating instruction and data were sent. But rigorous research led to the introduction in the mid 1980 of another type of formation evaluation technique called measurement while drilling (MWD) or logging while drilling (LWD). Here, the logging sensors are embedded in the thick walled drll collars used at the bottom of the drill string and measurement of formation properties is done continuously throughout the drill process.

Logging tools are one of the most important and useful tools available to a petroleum geologist because they provide direct information on the occurrence of hydrocarbons and the extent of such accumulations in reservoirs. A number of different logs exist and they are

classified based on the sources used to obtain the measurements, these, includes, electrical, nuclear and acoustic/ sonic sources. The petrophysical parameters that are determinable from logs in most cases are inferred from the physical parameters of the formation. The physical parameters include the bulk density, the interval transit time, resistivity, the spontaneous potential, the natural radioactivity and the hydrogen content of the rock. Log interpretation is the process by which these physical parameters are translated to the desired petrophysical parameters of porosity, hydrocarbon saturation, permeability, lithology, producibility and so on.

1.12.2 PETROPHYSICAL WELL LOG TYPES

Well logs which are used to quantify the hydrocarbon in place can be divide into three groups, these are; (Gamma ray log and spontaneous potential logs). They delineate reservoirs from non- reservoirs. Porosity logs (Density logs, Neutron logs and sonic logs). They are used to calculate porosity, identify lithologies, and discriminate oil from gas. Resistivity logs (Lateralog, Induction and Microresistivity logs). They are used with the porosity log to calculate hydrocarbon saturation.

LITHOLOGY LOGS

Gamma Ray (GR) Log

Gamma Ray Logs measure the natural radioactivity in formations. The total gamma ray (GR) measurement is a combination of the potassium, thorium and /or Uranium elements present in rock and fluid properties of any particular geological horizon. The higher GR readings typically but not always occur in front of the shale beds; lower reading usually occurs in front of other sediments. Gamma ray logs can be used to discriminate between reservoir and non-

reservoir, to estimate the shaliness (shale volume calculation) of the reservoir rock. They constitute an excellent correlation log and help depth matching subsequent logging runs with the first logging run in the well. The GR log is particularly useful for defining shale beds when the SP is distorted (in very resistive formations), when the SP is featureless (in freshwater bearing formations or in salty mud) or when the SP cannot be recorded (in non-conductive mud, empty or air drilled holes, cased holes)

SELF POTENTIAL (SP) LOG

Self-Potential is a self-induced, natural potential that occurs spontaneously between reservoir rocks and are fluid-filled bore hole. It is referred to as the SP Curve. The SP is usually recorded in combination with conventional resistivity or conductivity data and helps the analyst to segregate permeable strata from impermeable horizons.

The SP is used to locate the measured depths of geological horizons, to determine individual bed thickness. It is used in the determination of formation water resistivity (R_w) and in the estimation of the volume of shale/clay in permeable beds.

POROSITY LOGS

Sonic Log

The sonic tool measures the time it takes for sound pulses to travel through the formation. The results are displayed on a log in microseconds per meter / feet. The sonic log device consists of one or more ultrasonic transmitters and two or more receivers. Modern sonic logs are borehole-compensated (BHC) devices. These devices are designed to greatly reduce the spurious

effect of borehole size variations as well as errors due to tilt of the tool with respect to the borehole axis.

The sonic log is used in the calibration of seismic data, in calculating the porosity in layers of known lithology and in the evaluation of secondary porosities in combination with the Neutron and or Density tools.

The very good vertical resolution of the sonic logs with its reduced effects because of borehole compensation makes the sonic log excellent for correction. It can also be used to predict the possibility of occurring overpressures in a formation.

Density Log

This is a continuous record of a formation's bulk density. It is the overall density of minerals including the density of minerals (solid matrix) and the volume of free fluid enclosed in the pores (porosity).

The density log measures formation electronic density (number of electrons) linked to bulk formation density. A strong gamma ray source bombards the rocks with medium energy level gamma rays. The gamma rays collide the electrons in the formation and are subsequently absorbed by the formation (Compton scattering). The count rate of these scattered gamma rays at a fixed distance from the source is inversely proportional to the electron density of the formation. From the electron density, the bulk density is calculated.

Two separate density values are used by the density log: the bulk density and the matrix density. The bulk density is the density of the entire formation (solid and fluid) while the matrix density is the density of the solid framework of the rock.

Quantitatively, the density log is used to calculate porosity and indirectly, hydrocarbon density. Also, it is useful as lithology indicator (combined with Neutron logs); it can be used to identify overpressure and fracture porosity.

The logging technique of the density tool is to subject the formation to a bombardment of medium – high collimated (focused) gamma rays, and to measure their attenuation due to their backscattering and absorption tool source detectors. The rate of absorption and the intensity of the backscattered rays depend on the number of electrons (electron density) that the formation contains, which in turn is closely related to the common density of the materials. Dense materials have more electrons per unit – volume (electrons/cm³), with which the gamma particles can collide and lose energy. Hence, higher energy is absorbed in dense formations. In light materials with lower electron density, more gamma particles reach the detectors and are converted directly to bulk density for the log out printout. However, although electron density as detected by tool and real density are almost identical, there are differences when water (hydrogen) is involved. For this reason, the values presented on the density log are transformed to give actual values of calcite (2.71 g/cm³) and pure water (1.00 g/cm³).

The density log can be used to identify evaporate minerals, detect gas-bearing zones, determine hydrocarbon density and evaluate shaly-sand reservoirs and complex lithologies.

Neutron Log

The neutron log is a measurement of induced formation radiation produced by fast moving neutron bombarding the formation. It is an indication to formation richness in hydrogen. A high neutron count rate indicates low porosity, while low neutron count rate indicates high porosity.

The principal use of neutron logs is to identify porous rocks and determine an apparent porosity. Also, to discriminate oil from gas saturations (the porosity will appear very low when gas is measured). If the formation is shale free, the pores filled with liquid, and the matrix lithology known, the neutron log can be used to determine the porosity. When and /or shale are present, or if the lithology is not precisely known, neutron logs will probably not provide for accurate porosity calculations.

The anomaly above relative to the presence in a formation of gas and / or shale arises because in gas bearing formations, the neutron porosity recorded is too low due to low density of hydrogen atoms in the gas phase.

Shales contain clay-bound water (water which is chemically attached to the clay particles). The neutron log interprets this water as porosity, where in reality, no effective porosity is present.

Neutron log evaluates lithologies of formation in combination with density tool. It also checks (2.71 g/cm³) the consistency of lithologies as seen by the mud log, gamma ray (GR) and Density (2.71 g/cm³).

RESISTIVITY LOGS

The resistivity log is a measurement of a formation's resistivity, which is its resistance to the passage of an electric current. It can be measured directly by resistivity tools, or indirectly by conductivity tools. Conductivity data produced by induction tools measure a formation's conductivity or its ability to conduct an electric current. These values are generally converted directly and plotted as resistivity on log plots.

Most rock Materials are essentially insulators, while their enclosed fluids are conductors. Hydrocarbons are the exception to fluid conductivity, and on the contrary, they are infinitely resistive. When formation is porous and contains salty water, the overall resistivity will be very low. When this same formations contains hydrocarbons, its resistivity will be very high. It is this character that is exploited by the resistivity logs: high resistivity values may indicate a porous, hydrocarbon bearing formation.

Resistivity logs were designed to find hydrocarbon. Their principal quantitative use is to furnish the basic numbers for petrophysical calculations such as the volume of oil in place. Quantitatively, they can contribute to identify lithologies, texture, facies and overpressure of a formation.

Resistivity logs are used to determine hydrocarbon bearing versus water bearing zones, indicate permeable zones and determine porosity.

There are types of resistivity tools. They are;

The Dual Lateralog (DLL)

The Induction Log (DIL)

Both types measure the resistivity in three zones simultaneously.

Zone One – looks deep into the deep into the reservoir (LLD)

Zone Two – looks shallow into the reservoir (LLS)

Zone Three – reads the resistivity close to the well bore (MSFL)

In non – reservoirs, for example shale, all three resistivity devices read the same resistivity. This is because of the lack of permeability in non – reservoir rocks hence, there is no invasion of mud filtrate in the formation.

In porous reservoirs, mud filtrate resistivity (R_{mf}) will invade the zone close to the well bore replacing all the formation water resistivity (R_w) and part of the hydrocarbons if present.

The LLD (Zone 1) is hardly influenced by the bore hole, mud cake and invaded zone. It usually reads the resistivity of the uninvaded zone (R_t or R_o). The LLS zone is significantly influenced by the borehole, mudcake and invaded zone. It can be used to correct the LLD when necessary. The MSFL reads the resistivity of the invaded reservoir rock (R_{xo}).

Identification of potential reservoir intervals is achieved by looking for separation of resistivity curves in combination with gamma ray and porosity logs. Water-bearing reservoir is recognized by a relative high (deep) resistivity.

Evaluation of resistivity logs leads to the quantification (calculation) of water saturation in hydrocarbon –bearing intervals in a formation.

1.13 POST-STACK SEISMIC INVERSION ANALYSIS

Post-Stack Seismic Inversion Analysis is crucial to further enhance the accuracy of reservoir characterization and optimize well placement, especially in undrilled locations. Post-stack seismic inversion converts seismic reflection data into quantitative acoustic impedance models, providing a direct link between seismic response and subsurface rock properties such as lithology, porosity, and fluid content. This transformation enhances the vertical resolution of seismic data and reveals subtle changes in reservoir quality that may not be visible in

conventional seismic amplitude interpretation. By integrating inverted acoustic impedance with well logs and petrophysical parameters, it becomes possible to delineate reservoir facies continuity, heterogeneity, and lateral property variations across undrilled zones.

In TOKS Field, where accurate well positioning is essential for maximizing recovery, post-stack inversion provides a more data-driven, geologically consistent basis for identifying the most promising drilling targets. The inversion results can highlight potential high-quality sand bodies or hydrocarbon-bearing intervals beyond the reach of existing wells, thus reducing geological uncertainty. It also refines the low-frequency model used in static modeling by incorporating seismic-derived impedance trends, improving the confidence in reservoir connectivity and volumetric distribution.

Moreover, inversion-derived acoustic impedance maps can be cross-correlated with petrophysical properties such as porosity and fluid saturation, enabling more informed decision-making during field development planning. This helps minimize the risk of drilling dry or low-productive wells and ensures optimal well trajectory design for effective reservoir drainage.

Therefore, post-stack seismic inversion serves as a critical complementary technique to 3D static modeling by integrating both geological and seismic information to generate a more reliable subsurface model. In TOKS Field, it provides the quantitative foundation needed to enhance oil and gas well placement, improve recovery efficiency, and support sustainable field development in undrilled areas.

CHAPTER TWO

LITERATURE REVIEW

2.1 GENERAL GEOLOGY

The Niger Delta, located on the Gulf of Guinea along the western coast of central Africa, expanded into the Atlantic Ocean during the Tertiary period. Positioned at the mouth of the Niger-Benue river system, which drains an area of over a million square kilometers, mostly characterized by savannah-covered lowlands, this delta ranks among the world's largest. Its above-water portion spans roughly 75,000 km² and stretches over 300 km from its apex to its mouth. The sedimentary wedge within it, primarily composed of clastic materials, is estimated to have a maximum thickness of approximately 12 km (Doust and Omatsola, 1989).

The formation of the Niger Delta Basin began during the Aptian epoch. The area now occupied by the Niger Delta Basin was once part of the unsuccessful arm of the R-R-R (ridge-ridge-ridge) triple junction, which contributed to the separation of South America from Africa. The evolution of the Niger Delta Basin during the Tertiary period occurred in three main phases: The Pre-Santonian basin evolution, the Santonian-Paleocene basin evolution, and the Eocene-Recent delta phase. During the Pre-Santonian basin evolution, the oldest pre-Tertiary sedimentary basin, the Benue-Abakaliki Trough, originated as a failed arm of the triple-ridge system responsible for the separation of South America from Africa during the Aptian epoch. The opening of the three arms of the triple junction occurred at varying rates and times. By the mid-Aptian period in the South Atlantic, crustal stretching and downward warping led to the development of coastal evaporate basins. Subsequently, during the Lower Albian epoch, rift formation extended to the Gulf of Guinea, resulting in the formation of the Benue-Abakaliki

Trough. This trough accumulated over 3,300 kilometers of sediments from the Albian to Coniacian epochs before beginning to close, possibly due to crustal subduction. Following the tectonic folding during the Campano-Santonian phase, the Benue-Abakaliki Trough was uplifted to form the Abakaliki High, while the Anambra platform underwent downward warping, creating the Anambra Basin. This led to the encroachment of the sea onto the Benin flank basement, adjacent to the Anambra Basin, for the first time. Several sedimentary basins, including the Anambra Basin, the Afikpo Syncline, and the underformed Ikang Trough, existed from the Campanian to the Paleocene epochs.

The Eocene to Recent phase of the Niger Delta's evolution was triggered by epirogenic movements along the Benin and Calabar flanks, contributing to the continuous development of the delta up to the present time. This phase was characterized by regression interrupted by minor transgressions. Sediments in the Greater Ughelli Depobelt range in age from the Oligocene to the Miocene epochs, with depositional environments ranging from marginal marine to shallow marine environments (Short and Stäuble, 1967; Itiowe *et al.*, 2021).

2.2 PRIMARY STRUCTURAL FEATURES OF THE NIGER DELTA BASIN

The Niger Delta Basin's structural framework is dominated by gravity-driven tectonics, resulting from the immense load carried by the Niger River, depositing sediments and pushing them basin ward. The Niger Delta Basin has a good petroleum system, and its unique structural features play a crucial role in trapping and concentrating hydrocarbons. This creates favorable conditions for the accumulation of oil and gas and a dynamic structural setting with the following primary features:

Growth Faults

These large-scale syn-sedimentary faults are the most prevalent structural feature in the Niger Delta (Doust and Omatsola, 1990). As thick layers of sediments accumulate, the underlying, under compacted shales of the Akata Formation become unstable. This triggers the formation of listric faults, dipping gently seaward (basin ward). The movement along these faults creates tilted fault blocks and rollover anticlines in the overlying Agbada Formation which is a prime location for hydrocarbon trapping (Weber and Daukoru, 1975).

Shale Diapirs

The thick, over pressured shales of the Akata Formation become unstable and deform plastically, rising through overlying layers (Weber and Daukoru, 1975). These diapirs can act as seals for existing traps formed by growth faults or even create combination traps when they flank these faults, further enhancing hydrocarbon retention. These diapirs contribute to the structural complexity of the basin and create additional traps, sometimes flanking growth faults.

Back-to-Back Faulting

In some regions, sequences of antithetic (dipping in the opposite direction of a related fault) and synthetic faults form within the hanging walls of growth faults (Evamy *et al.*, 1978). These patterns further complicate the structural configuration, creating smaller scale traps and compartments within the basin.

Detachment Folds

Found commonly in the outer, deep-water parts of the delta where the Akata Formation is thickest (Corredor *et al.*, 2005). These folds form above the mobile shales of the Akata as a result of the downward slide of sediments, creating compressional structures.

2.3 GEOLOGY AND STRATIGRAPHY OF THE NIGER DELTA BASIN

2.3.1 REGIONAL GEOLOGY

The Cenezoic Niger-Delta is a prolific petroleum occupying an area in excess of 105000 km² (Avbovbor, 1978) it is one of world largest Delta complexes and major hydrocarbon provinces (Doust and Omatsola, 1990).The Niger-Delta sedimentary basin lies between longitudes 4⁰E and 8.8⁰E and latitudes 3⁰N and 6⁰N and is one of the most prolific hydrocarbon system in the world. The Niger-Delta clastic wedge formed along a failed arm of a triple junction system (aulacogen) that originally developed during breakup of the South American and African plates in the late Jurassic Burke (1972). The two arms that followed the southwestern and southeastern coast of Nigeria and Cameroon developed into the passive continental margin of West Africa, whereas the third failed arm formed the Benue Trough. Other depocenters along the African Atlantic coast also contributed to deltaic build-ups. Syn-rift sediments accumulated during the Cretaceous to Tertiary, with the oldest dated sediments of Albian age. Thickest successions of syn-rift marine and marginal marine clastics and carbonates were deposited in a series of transgressive and regressive phases (Doust and Omatsola, 1989). The Syn-rift phase ended with basin inversion in the Santonian (Late Cretaceous). Renewed subsidence occurred as the continents separated and the sea transgressed the Benue Trough. The Niger-Delta clastic wedge continued to prograde during Middle Cretaceous time into a depocenter located above the

collapsed continental margin at the site of the triple junction. Sediment supply was mainly along drainage systems that followed two failed rift arms, the Benue and Bida Basins. Sediment progradation was interrupted by episodic transgressions during Late Cretaceous time.

During the Tertiary, sediment supply was mainly from the north and east through the Niger, Benue and Cross Rivers. Cross and Benue Rivers provided substantial amounts of volcanic detritus from the Cameroon volcanic zone beginning in the Miocene. The Niger-Delta clastic wedge prograded into the Gulf of Guinea at a steadily increasing rate, in response to the evolution of these drainage areas and continued basement subsidence. Regression rates increased in the Eocene, with an increasing volume of sediments accumulated since the Oligocene.

Normal faults triggered by the movement of deep-seated, overpressured, ductile, marine shale have deformed much of the Niger-Delta clastic wedge (Doust and Omatsola, 1989). Many of these faults formed during delta progradation and were syndepositional, affecting sediment dispersal. Fault growth was also accompanied by slope instability along the continental margin. Faults flatten with depth onto a master detachment plane near the top of the overpressured marine shale at the base of the Niger-Delta succession. Structural complexity in local areas reflects the density and style of faulting. Simple structures, such as flank and crestal folds, occur along individual faults. Hanging-wall rollover anticlines developed because of listric fault geometry and differential loading of deltaic sediments above ductile shale. More complex structures, cut by swarms of faults with varying amounts of throw, include collapsed-crest feature with domal shape and strongly opposing fault dips at depth.

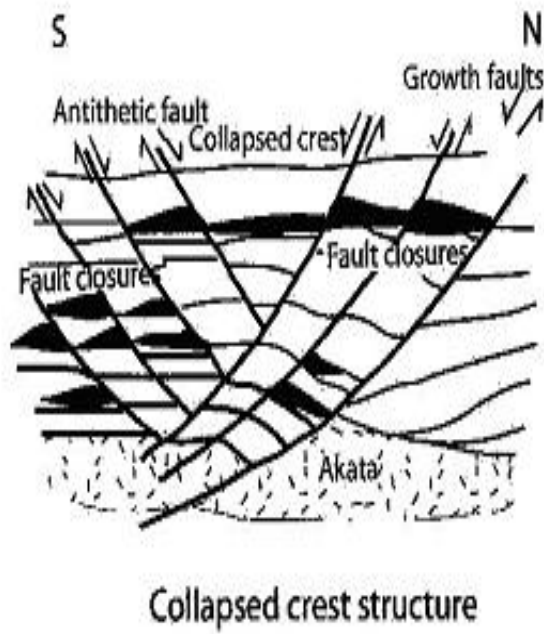
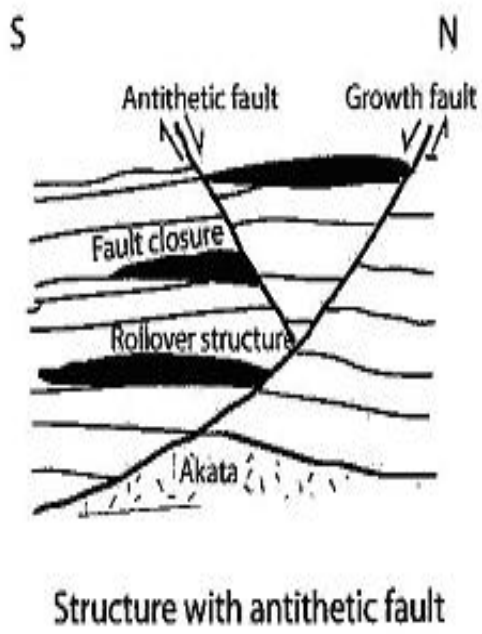
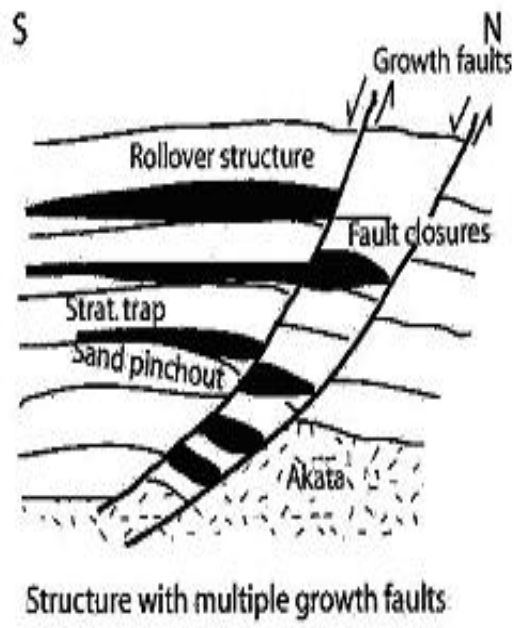
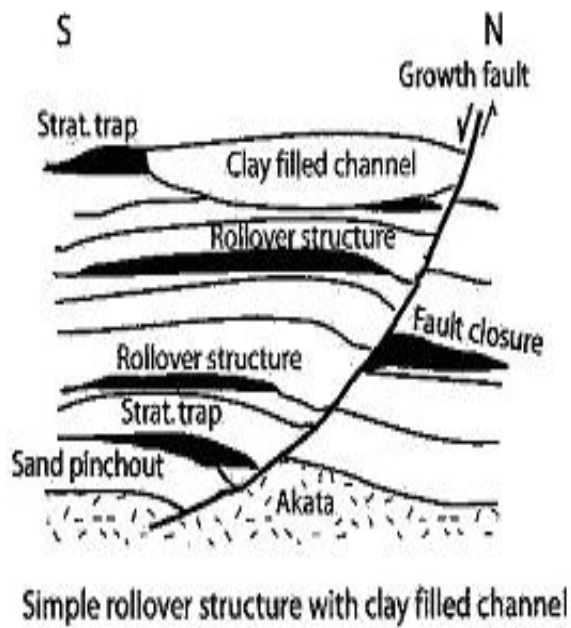


Figure 2.1: Niger Delta oil field structures and associated traps. Extracted from Doust and Omatsola (1990) and Stacher (1995)

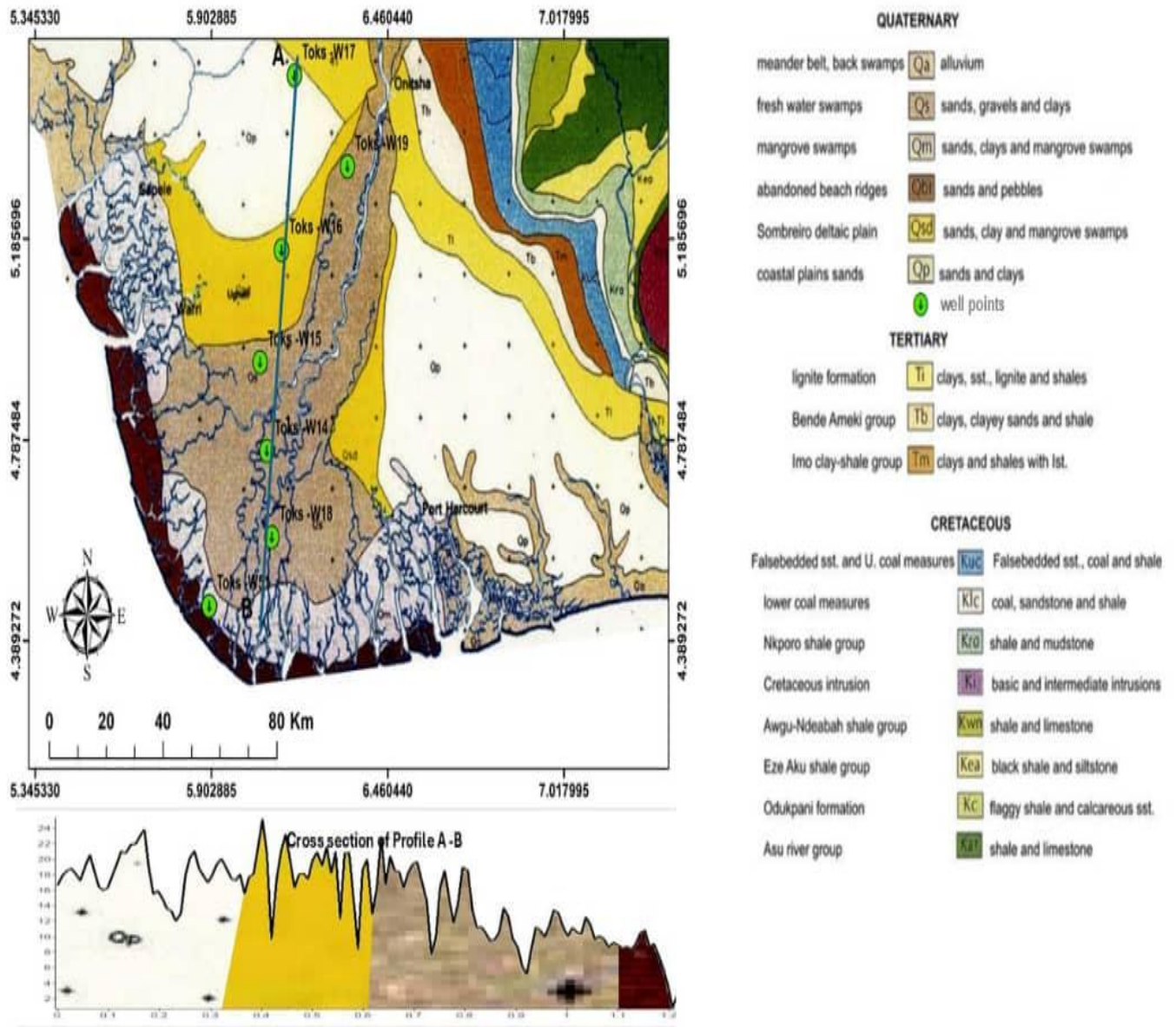


Fig 2.2: Regional Geology Map of the Niger Delta Basin showing TOKS Wells

The onshore portion of the Niger-Delta province is delineated by the geology of southern Nigeria south west Cameroon the north boundary is the Benin flank on east north eastern trending hinge line south of the West Africa basement massif. The north eastern boundary is define by outcrops of the Cretaceous on the Abakiliki High and further east – south east by Calabar flank in a hinge line bordering adjacent Precambrian. The Tertiary portion of the Niger-Delta is divided into three portion Formation representing prograding depositional facies that are distinguished mostly on the basis of the sand – shale ratio.

2.3.2 LOCAL GEOLOGY

The area under study is overlain with over 20 feet thick lateritic overburden at the surface. Below the lateritic overburden is fine to coarse grain sandstone which is underlain by clay sand to clay. The depth to water table is over 200feet with elevation of over 100m above sea level. The area is drain by the Ikpoba River the main river in Benin City.

2.3.3 STRATIGRAPHY OF THE NIGER DELTA BASIN

The three major lithostratigraphic units defined in the subsurface of the Niger-Delta (Akata, Agbada and Benin Formations).

2.3.3.1 THE AKATA FORMATION (PALEOCENE)

The Akata Formation is at the base of the delta and it is of marine origin, and is compose of thick shale sequence (potential source rock), it began depositing by the Eocene. The upper Akata Formation is the primary source rock of the Niger-Delta the Akata Formation rest on the basement rock. The lateral equivalent of the Akata Formation is the Imo shale. The formation is estimated to be 21,000 ft thick in the central part of the clastic wedge (Doust and Omatsola,

1989). The lithologies are dark gray shales and silts, with rare streaks of sand of probable turbidite flow origin (Doust and Omatsola 1989). Marine planktonic foraminifera make up to 50% of the microfauna assemblage and suggest shallow marine shelf deposition (Doust and Omatsola, 1989). The age of the formation ranges from Paleocene to Recent (Doust and Omatsola, 1989). Akata shales were interpreted to be deep-water lowstand deposits by Stacher (1995).

This basal formation, primarily composed of organic-rich, marine shales (Doust and Omatsola, 1990), serves as the foundation of the Niger Delta. It is under compacted and overpressure nature (Short and Stauble, 1967) plays a crucial role in driving gravity-driven deformation within the basin and acts as the source rock for the region's prolific hydrocarbon reserves. It consists of fine-grained sediments deposited in a marine environment. It contains organic-rich sediments that generate oil and gas.

2.3.3.2 AGBADA FORMATION (EOCENE)

The proto Niger-Delta lithologies consist of alternating sand, silt and shale arranged within ten to hundred feet successions defined by progressive upward changes in grain size and bed thickness. The strata are generally interpreted to have formed in fluvial-deltaic environments. The formation ranges in age from Eocene to Pleistocene, the sand stone of the Agbada Formation is the reservoir rock of the Niger-Delta, a transitional environment sediment. The Agbada Formation is underlain by Akata Formation the lateral equivalent of the Agbada Formation is the Asaba/Ogwashi Formation in Anambra Basin (Doust and Omatsola, 1989). It has a maximum thickness of about 13,000 feet.

This paralic sequence constitutes the primary reservoir unit of the Niger Delta (Tuttle *et al.*, 1999). It comprises interbedded sands and shales, deposited in diverse environments like fluvial, deltaic, and shore face settings (Reijers, 2011). The structural traps crucial for hydrocarbon accumulation within the Agbada Formation are often formed due to growth faults. It overlies the Akata Group, it contains coarser sediments and serves as the major oil-producing formation in the Niger Delta.

2.2.3 BENIN FORMATION (OLIGOCENE - RECENT)

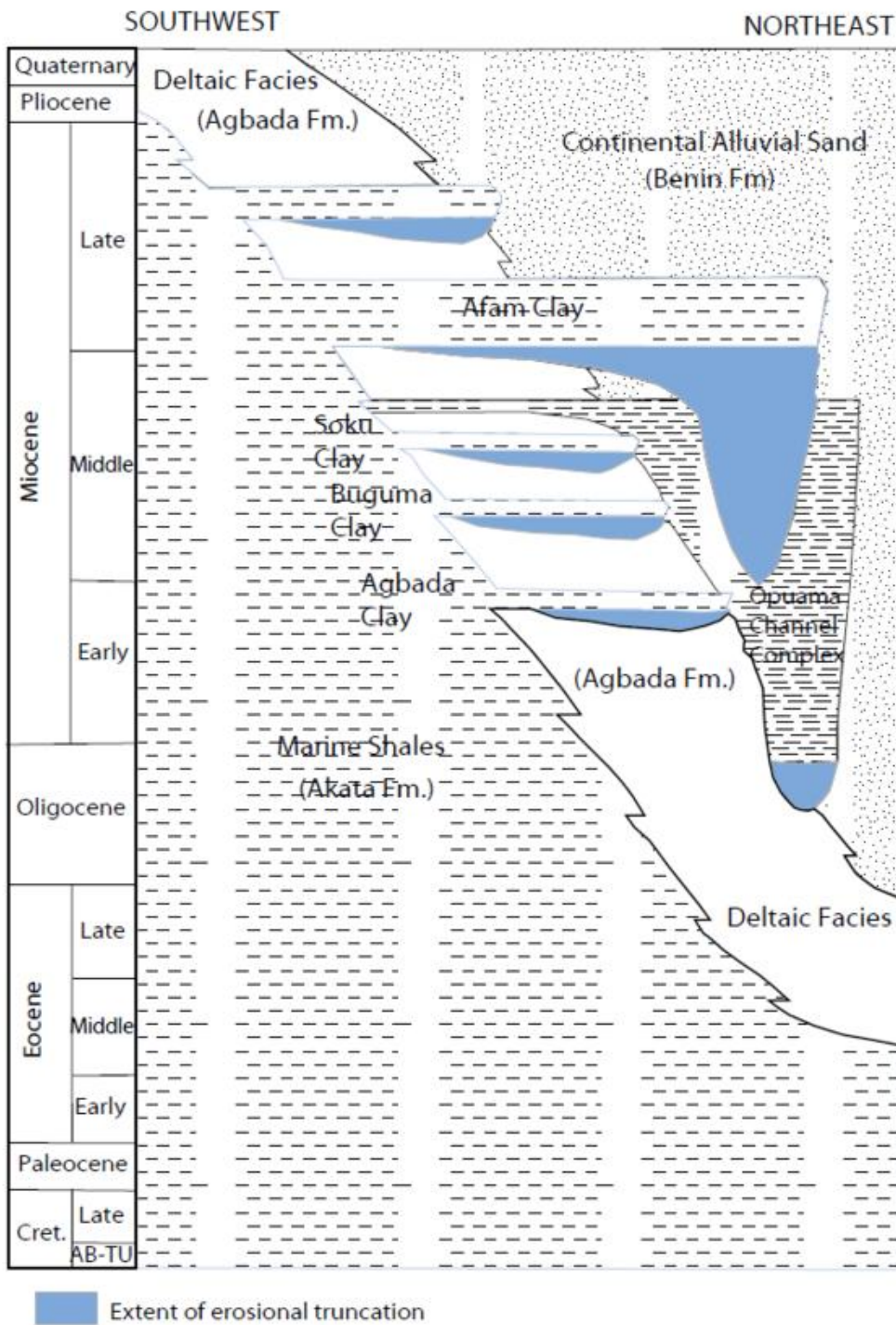
The Benin Formation comprises the top part of the Niger Delta clastic wedge, from the Benin-Onitsha area in the north to beyond the present coastline (Short and Stauble, 1967). The top of the formation is the recent subaerially exposed delta top surface and its base extends to a depth of 4600 feet (Short and Stauble, 1967). The base is defined by the youngest marine shale. Shallow parts of the formation are composed entirely of non-marine sand deposited in alluvial or upper coastal plain environments during progradation of the delta (Doust and Omatsola, 1989). Although lack of preserved fauna inhibits accurate age dating, the age of the formation is estimated to range from Oligocene to Recent (Short and Stauble, 1967). The formation thins basinward and ends near the shelf edge.

The uppermost formation is composed of continental fluvial sands and gravels (Short and Stauble, 1967). While its hydrocarbon potential is limited, it functions as a significant aquifer system in the region. It represents sediments deposited in a terrestrial environment.

Table 1.1: Stratigraphy of Niger- Delta (adapted from Ajibola, 2004)

AGE	FORMATION	LITHOLOGY	THICKNESS	SEDIMENTARY CYCLE	ENVIRONMENT
HOLOCENE	BENIN		max 2100m		CONTINENTAL
PLEISTOCENE					
PLIOCENE					
MIOCENE					
PALEOGENE	AGBADA		~ 3000m	REGRESSION	TRANSITIONAL TO MARINE
	OLIGOCENE		600 - 6000m	TRANSGRESSION	MARINE
	EOCENE				
PALEOCENE	AKATA				

Table 1.2: Stratigraphy of Niger- Delta (adapted from Ajibola, 2004)



2.4 REVIEW OF PREVIOUS WORK

Balogun *et al.*, (2019) analyzed the geological evaluation of hydrocarbon prospect of FOB-Field, Coastal Swamp Depobelt, Onshore, Niger Delta Basin, which focused on multidisciplinary data approach in building a gross depositional environment and well log seismic stratigraphic model for the aforementioned field, Nigeria.

Gupta *et al.*, (2016) carried out a study on "High-Resolution Reservoir Characterization Using Joint Inversion of Seismic and Well Log Data" - Explores the concept of joint inversion, where seismic and well log data are simultaneously inverted to obtain high-resolution subsurface models. The study focuses on the synergy between seismic and well log data in capturing detailed reservoir features and properties.

John and Oluwaseyi (2013) worked on petrophysical properties evaluation for reservoir characterization of Niger Delta using a field they called SEYI oil field said that reservoir with porosity ranging from 0.22 to 0.31 indicates a suitable reservoir quality, permeability values from 881.58md to 14425.01md attributed to the well sorted nature of the sands and hydrocarbon saturation range from 20.29% to 91.97% implying high hydrocarbon production.

The first detailed study of the Niger Delta was done by Shell in 1908. Early research focused on the geology (Reyment, 1969).

Most studies on the Basin's rock layers were done regionally. Early works looked at the Basin's structure, including Hospers (1965) discussing its gravitational field and structure and its hydrocarbon habitats Evamy *et al.*, (1978).

Short and Stauble (1967) established that the basin fill consists of the Benin, Agbada and Akata Formations, from youngest to oldest. Weber (1971) studied the sedimentology.

Other early works include Murat (1972) on stratigraphy and paleogeography, Weber and Daukoru (1975) on petroleum geology, Avbovbo (1978) on lithostratigraphy, Evamy and Haremboure (1978) on hydrocarbon habitats, and Ejedawe (1981) on oil reserves patterns.

Later studies looked at growth patterns and their effects (Knox and Omatsola, 1989), shale-sand interactions (Ekweozor and Daukoru, 1994), current understanding of hydrocarbon habitats (Statcher, 1995), sequence stratigraphy frameworks (Adesida *et al.*, 1997), depositional patterns related to deformation (Hooper *et al.*, 2002), and sequence stratigraphy of specific fields (Owoyemi, 2004; Owoyemi and Willis, 2006; Magbagbeola and Willis, 2007; Ebinola *et al.*, 2010).

Reijers (2011) concluded there were 39 sea level rise events reflected in the delta. Avuru *et al.* (2011) found increasing fault complexity with 3D seismic data. Other studies looked at depositional environments (Omoboriowo *et al.*, 2012), burial history modeling (Ojo *et al.*, 2012), sequence stratigraphy and structure (Oresajo *et al.*, 2015), and hydrocarbon generation (Oladotun *et al.*, 2016).

More recent works include sequence stratigraphy analyses (Ukpong *et al.*, 2017; Dim and Onuoha, 2017; Ukpong and Anyanwu, 2018), characterization and seal integrity (Adagunodo *et al.*, 2017), stratigraphy and deformation (Dim, 2017), palaeoenvironmental interpretations, environmental reconstructions (Lucas and Fregene, 2018), geological evaluations (Balogun *et al.*, 2019), sequence stratigraphy and petro physical analysis (Dim *et al.*, 2019), and structure and stratigraphy (Etimita and Beka, 2020).

Kinrin-ola *et.al.*, (2024a) worked on Hydrocarbon Play Elements of the Sedimentary Succession Penetrated by the Drill in EG-1 Well, Niger Delta Basin, Southern Nigeria and concluded that five (5) hydrocarbon play elements (reservoir rock, source rock, cap rock, seals and trap) were identified in the well succession.

Kinrin-ola and Nduezeuko (2024b) carried out a research on the Sedimentological Studies of the Sedimentary Succession Penetrated by the Drill in NC-1 Well, Greater Ughelli Depobelt, Niger Delta Basin, Southern Nigerian and concluded that in the NC-1 Well and four (4) lithofacies (Shale, Sandstone, Shaly Sand and Sandy Shale), three (3) associated minerals (Quartz, Iron Oxide and Mica) and five (5) hydrocarbon play elements (source rock, reservoir rock, caprock, seals and trap) were identified.

Maju-Oyovwikowhe and Okudibie, (2023) worked on Sedimentological and Petrographic analysis of sidewall samples from the Niger Delta Basin, Nigeria: Implications for Depositional Environments and Reservoir Quality and concluded that visual observations under a binocular microscope revealed shale and sandstone lithologies, mica, quartz and silt associated minerals and carbonate materials as well as identification of hydrocarbon presence through hydrocarbon stain tests.

Maju-Oyovikowhe and Olowu (2023b). Grainsize Analysis and Depositional Environment of Sediments in Niger Delta Basin at Isihor and Osasogie Locations, Benin City and concluded that the grainsizes of the sediments varies from mud to silt to fine sand to medium sand to coarse sand across both locations deposited in fluvial setting.

Kinrin-ola *et al.*, (2022a) worked on Hydrocarbon Play Elements of Sedimentary Succession Penetrated by the drill in OLA-1 Well, Niger Delta Basin, Southern, Nigeria and

concluded that the studied OLA-1 well situated in Niger Delta Basin in Southern Nigeria has five (5) hydrocarbon play elements recognized and includes; source rock, reservoir rock, cap rock, seal rock and traps. Two (2) probable reservoirs, two (2) potential reservoirs, one (1) probable source rock, four (4) potential source rock, three (3) cap rocks, four (4) seals and three (3) traps.

Kinrin-ola *et al.*, (2022b) worked on Lithofacies and Mineralogical Composition of Sedimentary Succession Penetrated by the drill in OLA-1 Well, Niger Delta Basin, Southern Nigeria and concluded the studied OLA-1 well situated in Niger Delta Basin in Southern Nigeria has four (4) lithofacies; Sandy Shale, Shale, Sandstone and Shaly Sand and four (4) minerals; Mica, Iron Oxide (Hematite), Feldspar and Quartz.

Igodaro *et al.*, (2016) worked on Sedimentological Resolution of Hydrocarbon Play Elements of OGE-# 1 Well, Greater Ughelli Depo-Belt, Niger Delta Basin and concluded that the lithologies recorded are sandstone, shaly sand, sandy shale and shale ranging from coarse grained, well sorted to poorly sorted at different lithologies.

Ilevbare and Imasuen (2020) carried out a study on sedimentology and maturity of Ajali Formation, Benin Flank, Anambra Basin, Nigeria and concluded that the Ajali Sandstone are medium sand, poorly to moderately sorted, coarse to strongly coarse skewed leptokurtic grains. Also, the grains are sub-angular to sub-rounded, moderate to well sorted grains that are chemically immature to sub-mature sandstone.

Lucas and Kinrin-ola (2020) worked on Lithofacie, Minerals and Hydrocarbon Play Elements of the Sedimentary Succession Penetrated by the Drill in JOOAK-1 Well, Anambra Basin, Southern Nigeria and concluded that four (4) lithofacies (Sandstone, Sandy Shale, Shale

and Shaly Sand), four (4) associated minerals (Feldspar, Quartz, Mica and Iron oxide) and four (4)

hydrocarbon play elements (seal, trap, source rock and reservoir rock) were penetrated in the well succession.

Amiewalan and Lucas (2020) worked on the Sequence Stratigraphic Interpretation of FX-1 and FX-2 wells, Onshore Western Niger Delta, Nigeria and revealed that FX-1 well have five (5) depositional sequences, eight (8) maximum flooding surfaces and seven (7) sequence boundaries, also FX-2 well have four (4) depositional sequence, five (5) Maximum Flooding Surfaces and five (5) sequence boundaries.

Lucas and Osezele (2018) carried out a research on Maastrichtian to Danian Sedimentary Biozonation and Sequence Stratigraphy in Alo-1 Well, Anambra Basin, Southeastern Nigeria and concluded that sequence stratigraphically, two (2) maximum flooding surfaces (MFS) and one (1) sequence boundary (SB) were defined in the Danian, three (3) maximum flooding surfaces (MFS) and two (2) sequence boundaries (SB) were defined in the Maastrichtian.

Maju-Oyovikowhe and Lucas (2019a) worked on Depositional Facies Analysis using core samples from Greater Ughelli Depobelt, Niger Delta Basin, Nigeria and concluded that the core samples contained three (3) sandstone and one (1) mudrock lithofacies deposited in an aggradational depositional setting.

Maju-Oyovikowhe and Lucas (2019b) carried out a research on Sedimentological Analysis of core samples to decipher Depositional Environments: A Case Study of Valz-01 Well, Niger Delta Basin, Nigeria and concluded that the core samples contained six (6) lithofacies that

include Muddy heterolith, Laminated fine sandstone/siltstone, Fine sandstone/siltstone, Hummocky fine sandstone/siltone, Laminated shale sandy and shale within three (3) depositional environments that includes maine, transitional and continental environments.

Asadu and Ibe (2017) worked on Petroleum Geology of Outcropping Sediments along Imiengba Road in Etsako East Local Government Area of Edo State, Southern Anambra Basin Flank, Nigeria: Inference from Sedimentology and Organic Geochemistry and concluded that the main lithofacies identified in the study area are sandstone, shale and claystone. Also the sandstones are fine to medium-grained and friable, the textural analyses reveal the sandstones to be subrounded, moderately to poorly sorted.

Avbovbo (1978) worked on the Niger Delta Basin Lithostratigraphy and concluded that the composite Basin is made up three units; Akata, Agbada and Benin Formation and that the southward prograding Tertiary Delta implies the Akata Formation, and the tributaries channels and deltaic plain environment representing the Agbada Formation.

Ikuoyomwen *et al.*, (2022) worked on Lithofacies and Mineralogical Composition of the Sedimentary Succession Penetrated by the Drill in AB-Well, Greater Ughelli Depobelt, Niger Delta Basin, Nigeria and concluded that the studied AB-Well in the Niger Delta Basin is situated in Greater Ughelli Depobelt has four (4) lithofacies that were identified in the well and they include; Sandstone, Shaly sand, Shale and Sandy shale. The minerals identified in the studied well are Mica, Quartz, Feldspar and Iron Oxide (Hematite). Thirty lithozones were identified in the studied well and they comprise of thirteen (13) Sandstone unit, Nine (9) Shale unit, two (2) Sandy shale and six (6) Shaly sand unit.

Ikuoyomwen and Kinrin-ola (2022) worked on Hydrocarbon Play Elements of the Sedimentary Succession Penetrated by the Drill in AB-Well, Greater Ughelli Depobelt, Niger Delta Basin, Nigeria and concluded that the The hydrocarbon play elements recognized includes; source rock, reservoir rock, cap/seal rock and traps. Eleven source rock unit were identified and are seen within the depth range 3802m-1698m; nine (9) probable source rock and two (2) potential source rock. Nineteen (19) reservoir rock unit were identified within lithofacie unit two (2) and thirty (30); fourteen (14) probable reservoirs four (4) potential reservoirs. Eleven (11) cap/seal rocks and nine (9) traps were also identified in the analysed section of AB-Well, Greater Ughelli, Niger Delta Basin.

2.4.1 REVIEW OF STUDIES THAT INTEGRATE WELL LOGS, SEISMIC DATA AND CORE DATA

Chang *et al.*, (2013) worked on Core-Log-Seismic Integration for Improved Reservoir Prediction", exploring a comprehensive integration approach that incorporates core data into the correlation of well logs and seismic interpretations. The study highlights the significance of core-based facies analysis in refining seismic interpretations and improving reservoir predictions.

John and Oluwaseyi (2013), in their petrophysical properties evaluation for reservoir characterization of Niger Delta SEYI oil field and concluded that the reservoir with porosity ranging from 0.22 to 0.31 indicates a suitable reservoir quality, permeability values from 881.58md to 14425.01md attributed to the well sorted nature of the sands and hydrocarbon saturation range from 20.29% to 91.97% implying high hydrocarbon production.

Smith *et al.*, (2010) worked on Quantitative Integration of Well Logs and Seismic Data for Reservoir Characterization" This investigates the quantitative integration of well logs and

seismic data using advanced petrophysical modeling techniques. The work emphasizes the importance of incorporating petrophysical properties derived from well logs into seismic inversion processes for enhanced reservoir characterization.

Yilmaz *et al.*, (2005) worked on "Integrated Reservoir Characterization Using Well Logs, Seismic, and Core Data". This foundational study emphasizes the importance of combining seismic data with well log and core data for reservoir characterization. It introduces a methodology that integrates seismic attribute analysis, well log correlation, and core-derived rock properties to improve the accuracy of reservoir models.

Li *et al.*, (2019) investigates the integration of geophysical data (seismic) with petrophysical data (well logs and core) to enhance reservoir modeling. The investigation discusses methodologies for quantitatively linking seismic attributes with petrophysical properties for improved reservoir characterization.

Aigbadon *et al.*, (2021) worked on "Depositional Environments and Reservoir Evaluation of Otuma Pil Field, Niger Delta Basin, Nigeria" and concluded that the reservoirs reflect highly porous and permeable channels with the values ranging between 0.10 to 0.30 and permeability values ranging from 48 md to 290 md. The water saturation values range from 0.39 to 0.52.

Ayemelo (2016) worked on "Petrophysical Evaluation of Well B, ALPHA Field, Onshore Niger Delta" and concluded that the net – to – gross ratio calculated was 0.36, the porosities range is between 23.4 % and 27.7% and water saturation range between 9% and 57%, the petrophysical parameters thus, reflecting prolific reservoirs within the well.

Anyim (2010) worked on Petrophysical Evaluation of Integrated Wireline Well Logs in FABI Field, Niger Delta Nigeria and concluded that three zones in Fabi_02 well, one zone in Fabi_03 Well have favorable plays of petrophysical properties, while Fabi_04 Well has two zones of slightly favorable plays of petrophysical properties, thus reflecting a good hydrocarbon producibility status on the reservoirs of the wells.

Danwazan, *et al.*, (2023) worked on Integrated Modelling and Reservoir Characterization of Ataga Field, Niger Delta Basin Nigeria and concluded that two (2) viable hydrocarbon bearing reservoirs AT1 and AT2 were delineated and average values of porosity, permeability, Net to Gross (NTG) and volume of shale are in the range of 15% - 77%, 44.5% - 75.5%, 25.5% - 85%, 15% - 75%, 0.70 – 0.80 and 0.11 – 0.38 respectively which goes further to show that the both reservoirs have fair characteristics that are suggestive of the presence of hydrocarbon accumulation.

Adagunodo, *et al.*, (2022) worked on Characterization of Reservoirs and Depositional Study of J-P Field, shallow offshore of Niger Delta Basin, Nigeria. Scientific African and concluded that the petrophysical parameters across the delineated reservoirs varies from 19% to 21%, thickness varies from 24m to 122m, volume of shale varies from 15 % to 29%, water saturation varies 225 to 60% and hydrocarbon saturation varies from 40% to 78%. The depositional environment was interpreted as comprised of prograding delta, transgressive marine sands fluvial channels and deltaic setting, thus porosity range is said to be of good to very good quality and high hydrocarbon saturation of oil.

Osinowo, *et al.*, (2018) worked on Reservoir Description and Characterization of Eni Field Offshore, Niger Delta, Southern Nigeria and concluded that three (3) lithologic units with

favourable petrophysical properties classified as hydrocarbon saturated clastic reservoir were delineated showing serrated, cylindrical and coarsening upward log motif signatures and indication of the reservoir sands to consist mainly of stacked sands and shale sequence.

2.4.2 REVIEW OF POST-STACK SEISMIC INVERSION

Sasayed *et al.*, (2024) worked on Utilizing Post-Stack Seismic Inversion for delineation of gas-bearing sand in Pleistocene Reservoir, Baltim Gas Field, Nile Delta, Egypt and concluded that the results confirms the presence of gas-bearing sands in the El-Wastani and estimate an Original Gas Inplace (OGIP) of approximately 0.4Gm³ for well WB-1 and 6.6Gm³ for well TERSA-1ST. The findings support informed descision-making for drilling locations and enhance the potential for successful gas production in Baltim Field.

Mbou *et al.*, (2024) worked on Seismic Inversion Techniques and Attribute Analysis for Accurate Well Placement in Offshore Niger Delta Basin, Nigeria. The study integrate seismic inversion with seismic attribute analysis two to better characterize the reservoir in the MTW Field in deep – offshore Niger Delta State. Using five (5) wells of complex suites of petrophysical log 3D-Seismic data, checkshot and other well information were used. The lithostratigraphic and petrophysical analytical result shows five (5) reservoir sand with thickness of 13.42m, high effective porosity of 27% permeability of 3187.53m, low water saturation of 34% and low shale volume of 11% in the Reservoir A which are indication of good reservoir quality and productivity. Seismic interpretation shows 31 growth and antithetic faults in a NE – SW and NW – SE directions respectively. Root Mean Square (RMS) result shows high amplitude reflectivity which is a measure of zone of interest. Based on this seven (7) prospects and three (3) leads were identified. The seismic inversion. The seismic inversion results show a

high level of accuracy with a correlation coefficient of 0.997, 0.997, 0.995 and 0.996 in MTW-001STI, MTW-003STI, MTW-004STI and MTW-005 wells respectively. The acoustic impedance successfully resolved and improved on the relation of the seismic stacking velocity especially at reservoir layers and depth deeper than 3600m.

Tiekuro *et al.*, (2024) worked on Application of Post Stack Acoustic Impedance Inversion to Lateral Rock Property Prediction: A case Study of Eti-Field Offshore Niger Delta and concluded that the study presents the result of a Model-based seismic inversion technique which was used to invert an acoustic impedance structure within a reservoir interval by integrating well logs and 3D post stack seismic data obtained from Eti-field offshore Niger Delta and concluded that the inversion workflow used includes forward modelling of reflection coefficients from a low frequency impedance model driven from well logs and convolution of the reflection coefficients with a source wavelet derived from the seismic data. P-impedance inversion analysis at the control well location gave a near perfect correlation 0.993686 between the original P-impedance log, initial guess P-impedance model log and inverted P-impedance log. The estimated error shows 5533.1 which corresponds to 0.112308 about 11.23%. Seismic inversion analysis shows an acoustic impedance structure with P-impedance values ranging from 7000 to 50000 ft/s*g/cc and have a general increase with depth trend. The Impedance slide extracted from the impedance volume at top of the reservoir predicted lateral variations in P-impedance at well control and away from well control. The findings are invaluable in delineating more prospective reservoir zones in the field and thereby enhancing optimum field development which aids in reservoir management descisions.

Schwedersky *et al.*, (2017) worked on Post-Stack Seismic Inversion and Facies Prediction using Bayesian Inference, Boonsville Field, Fort Worth Basin, United States of

America: A case Study. The work shows a methodology derive facies and sand probability volumes from post-stack 3D- Seismic data. The seismic data was inverted to a P-Impedance volume using a constrained Sparse - Spike algorithm. Probability density functions, derived from well logs together with Bayesian inference were used to derive sand probabilities and facies volumes at each voxel in the impedance volume. The result obtained shows a reasonable match to the measured logs (within the seismic resolution). The outcome represent benefits to the geological interpretation because they are themselves a geological model of the subsurface. They can also be assessed to evaluate risk and uncertainty involved in the process by looking to the probability sand volumes and driving different scenarios from different models.

Maurya and Sarkar (2016) worked on comparison of Post-Stack Seismic Inversion Methods: A case study from Blackfoot Field, Canada. The objectives is to use several standard Seismic Post-Stack Inversion methods for reservoir characterization and compare their results. Model-Based (MBI), Coloured (CI), Sparse-Spike (SSI) and Band-Limited (BLI) inversions are applied to the Post-Stack Seismic data from the Blackfoot Field, Alberta, Canada. In each case the data inverted into P-Impedance and density volume. The final stacked section shows high-resolution images within the time – depth range of 300 to 1300ms. All inversions show mutually consistent results with low impedances within the target hydrocarbon sand in the channel. All the Post – Stack inversion methods show higher correlation coefficient (0.99) and least RMS Error (778 m/s² g/cc) and hence better for Blackfoot Seismic data. Geostatistics Method – Probablistic Neural Network was also employed to estimate physical (porosity) variations within the sand channel (reservoir) of the Blackfoot field. The coefficient between the predicted and measured porosities following that the Probablistic neural network show that Sparse – Spike Inversion when used as an external attribute is more accurate and produces high –resolution images

compared to that estimated with the use of model based and coloured inversion. From the estimate, the predicted logs correlation of 0.8, 0.84 and 0.86 using neural network algorithm and MBI, CI and LPSSI as external attribute respectively. Out of the four (4) Post – Stack Seismic Inversion methods used here, the probabilistic neural network method with Sparse Spike Inversion provides a higher correlation coefficient than that estimated for other methods.

2.4.3 REVIEW OF OTHER WORKS IN THE NIGER DELTA BASIN

Akhilome (2015) worked on groundwater from borehole water in Ekenwan and Ughoton community in Benin City, Nigeria and find out that one of the borehole was contaminated with coliform count as a result of its proximity to a stream with active human activities. The surface water feeds the groundwater at a point in time and affects the groundwater.

Patrick *et al.*, (2002) carried out water quality testing on six borehole and three open wells at Okhoro in Benin City, Nigeria and the result shows a higher pH, Cr and Cd concentration than the recommended threshold value by the World Health Organization (WHO). Other abnormal level of the parameter measured were Zn, faecial coliform, E. coli and faecial streptococci in which case are dangerous to human health.

Olasehinde *et al.*, (2015), carried out a study on the statistical assessment of groundwater quality in Ogbomosho, Nigeria using multivariate statistical analysis, factor analysis and Kaiser Normalization. The result reveals six sources of solutes which correspond to six possible sources of groundwater pollution. Five factors (1, 2, 3, 4 and 6) originate from the natural sources while factor 5 is from anthropogenic source. Based on the calculated water quality index, the groundwater in the area falls under poor water and it was attributed to the enrichment of the groundwater with fluoride, major ions and heavy metals. The water type in the area is calcium

bicarbonate type. The efficacy of factor analysis and water quality index in the characterization of groundwater geochemistry in Ogbomosho, southwest Nigeria was demonstrated in the study.

Erah *et al.*, (2002) studied inorganic chemicals and microbial contaminants from six boreholes and three open wells from Okhoro and Teboga in Benin City. Results showed that all the water samples were contaminated with abnormal levels of Pb, Zn, Cd, Cr and faecal coliform. They concluded that consumption of water from these wells and boreholes was capable of causing health hazards to the consumers.

Imeokparia and Offor (2002) worked on the laboratory analysis of water samples from Ogba River in Benin City, Nigeria and the results reveals high level of Fe, Pb, Mn, Ni and Cu.

Issa *et al.*, (2010) did a study on the Assessment of Sediment Contamination by Heavy Metals) in River Orogodo, Agbor, Delta State, Nigeria. This work covers sampling of whole sediment and analysis to ascertain the level of contamination of heavy metals in River Orogodo. Sediment samples from the coast of River Orogodo in Agbor, Delta State, Nigeria were sampled over four months (May to August) and analyzed for heavy metals (Cd, Mn, Fe, Cu, Ni, Pb, Zn, Cr) using Atomic absorption spectroscopic method. Some specific physicochemical characteristics, such as organic matter, pH and conductivity which are known to influence the interactions and dynamics of metals within the sediment matrix were also determined. The result of the analysis indicates significant difference ($p < 0.05$) in pH, organic matters, Mn, Zn and Cr levels for the four-month variation. The significant correlation ($p < 0.05$) however exists between some of the metals and some also show high correlations at $p < 0.01$. The concentrations of most heavy metals were low, but iron content was higher than the background value and DPR standard for soil/sediment which indicates significant contamination by iron in the water body.

Izeze *et al.*, (2018), carried out groundwater studies in order to determine the extent of leachate contamination in groundwater from selected dumpsites in Effurun South-South, Nigeria. The result shows a major cation concentration in the order of $\text{Ca}^+ > \text{Mg}^{2+} > \text{Fe}^{2+}$ while major anion was in the order of $\text{Cl} > \text{SO}_3^{2-} > \text{NO}_3^- > \text{PO}_4^{3-}$. The high pH also indicated the presence of toxic metals such as Pb, Cd and Fe. Health hazards such as typhoid fever and worm infestation were imminent due to pollution.

Omo Irabor and Izeze (2018), carried out a study to determine the extent of contamination from heavy metals in soil samples collected from selected dumpsites in Agbor area of South South Nigeria. The heavy metals analyzed were in the order of $\text{Fe} > \text{Zn} > \text{Ni} > \text{Cu} > \text{Pb} > \text{Cr} > \text{Cd}$. The high contamination by heavy metals indicated leachate migration from the open dumpsites. They concluded that unless preventive measures were carried out leaching would continue and contaminate the groundwater over a period of time.

Imasuen and Izeze (2019), carried out a study in parts of Sapele and Warri Local Government Areas of Delta State in order to determine the different hydrogeochemical facies and understand the groundwater flow regime and its effect on the chemical composition of the groundwater so as to evaluate the anthropogenic effects on groundwater quality in the study area. Twenty-five (25) water samples were taken from Sapele (18) and Warri (7) in one-liter plastic cans. The analyses carried out indicated the presence of chloride ion as the dominant parameter. Chloride shows a negative correlation with all other parameters thus indicating that its source is from surface saline waters close to those areas with high chloride concentrations. The presence of ammonia in such high concentrations and its strong positive correlation with phosphate supports that its source is as a result of pollution from sewage. The positive correlation of phosphate, sulphate, nitrate and TDS also indicate pollution from sewage. GPS readings and

computation of several hydrogeological parameters showed a SW direction of groundwater flow for Sapele and a SE flow direction for Warri. The presence of ammonium at levels higher than geogenic (geologically related processes) levels is a strong indicator of fecal pollution. The groundwater in the area is mostly acidic with high chloride concentrations. Contamination from anthropogenic sources is mainly as a result of waste waters from brines released as by-products of oil exploration activities and leaky septic tanks. The presence of chloride is from the proximity of areas that lie southward towards the Atlantic Ocean and the fact that water doesn't mix excessively at greater depths but the chloride levels are still within accepted standards for domestic use. Domestic wastes from septic tanks and improper waste disposal are the main sources of ammonium in the groundwater of the study area, and this reduces the groundwater quality in the area marked.

Izeze and Okumoku (2018), carried out a study to determine the degree contamination of soils and groundwater due to heavy metal contamination. The result of the analyses showed that the groundwater in the study area is mostly acidic with high chloride concentration. Contamination was believed to be as a result of anthropogenic sources, mainly septic tanks.

Moore *et al.*, (2009), studied the assessment of heavy metal contamination in water and surface sediments Maharlu saline Lake SW of Iran in order to evaluate the environmental pollution of the lake. The total concentrations of As, Cr, Co, Cu, Cd, Pb, Zn, Ni, Fe, and Mn were determined in the surface sediments and water of the lake. As and Cr were not detected in the water samples, however, the mean concentrations of other dissolved metals in Maharlu Lake water were 0.28 mg/l for Cu, 0.28 µg/l for Cd, 5.17 µg/l for Pb, 0.37 mg/l for Zn, 2.36 µg/l for Ni, 2.88 µg/l for Co, 10.4 mg/l for Fe, and 1.5 mg/l for Mn. Different water and sediment quality assessment approaches indicated that in the lake, metals can be divided into three different

groups: (a) Co, Pb, and Cd. These metals have the highest enrichment factors (the mean values are 35.8, 76.9, and >36.6, respectively), geoaccumulation indexes (the mean values are >3), and contamination factors (11.1, 29, and 8, respectively) compared with other studied elements; thus, the Maharlu Lake is highly polluted with these metals, and they are mainly from anthropogenic sources; (b) Cu, Zn, and Ni. Their mean enrichment factor values are 6.6, 3.4, and 6, respectively; their mean geoaccumulation indexes are <1, and their mean contamination factor values are 2, 1.1, and 2, respectively. The enrichment factor of these metals is higher than 10 only north of the lake. The Lake was found to be moderately polluted with these metals, and they were from both natural and anthropogenic sources; (c) Cr, As, Fe, and Mn. These elements had the lowest mean enrichment factor (1, 3.5, 2, and 4.2, respectively), geoaccumulation indexes (≤ 0), and contamination factor (0.32, 0.91, 0.63, and 1.5, respectively) values; thus the Maharlu Lake is not polluted with these elements, and they are mainly from natural sources. Results indicated that the Maharlu Lake sediments have a high contamination degree (56.66). Comparisons with consensus-sediment quality guidelines reveal that Ni and Pb posed the greatest environmental threat to aquatic organisms. In order to protect the lake from further contamination, the treatment and recycling of wastewaters discharged into the lake is needed.

Ighere *et al.*, (2014), conducted a survey on the physico-chemical characteristics of River Jamieson. The surface water from five (5) randomly sampled locations were tested for twelve (12) PCCS. The result showed that all except temperature were within WHO permissible limit. Lead measured were undetected in three of the five (5) stations and were very minimal in the other two (2). They concluded that there is need to ensure sustainable uses and guide against future contamination.

Ezemonye and Enuneku (2012) studied the hepatic bioaccumulation of cadmium in crowned bull frog and flat backed toad in Oghara. The amphibians were exposed to sub lethal cadmium concentrations of 0.25, 0.50, 1 .00 and 2.00 mg/l. Bioaccumulation in both species increased significantly in both periods of exposures. The study suggested that the release of cadmium into the environment could possibly affect the well-being of amphibians as well as resulting in further decline of these organisms that contribute significantly to the food web. They concluded that there is need to protect amphibians from habitat alteration due to cadmium pollution with a view to sustaining the rich biodiversity in the Nigerian Niger Delta ecological zone.

Nwankwoala *et al.*, (2014) investigated heavy metal contamination in Yenagoa town and found concentrations of Fe, Mn, Ni, Cr, Pb, As, Cd, Hg and Cu above WHO limit for drinking water. They attributed it to industrial discharge and subsurface injection of chemicals being an oil producing area.

Pan Ocean Oil Company (2005) carried out an update ETA studies of its proposed Ovade-Ogharefe gas processing plant and reported that water samples analyzed showed slight acidity, nitrate, nitrite, ammonia, phosphorus and salinity related parameters (chloride, sulphate, conductivity and total dissolved solids) were low. Soil composition dominated by sand, with texture of the soil ranging from sand to sandy clay loam and sandy loam. Grain size analysis distribution showed that majority of the sand are in the medium and very fine sand range. The pH ranges from strongly acidic to alkaline, Low TOC and conductivity suggesting a fresh water environment. Metals occurring decreased in the order of Fe>Ni>Cr and others occur in traces.

Akujieze and Irabor (2014) assessed the impact of waste disposal on the soil and groundwater systems in the Benin West moat. Eleven (11) soil samples and eight (8) groundwater samples from pumping boreholes on both sides of the moat were drawn. Samples were analyzed for their chemical, heavy metal constituents (including microbial in water). Results reveal contamination of soil with Al, Cd, Fe, Pb and THC; while the groundwater was polluted with presumptive coliform and heavy metals: Al, Cd, and Pb. They concluded that the once protective moat is now a likely area of phytotoxicity and general environmental toxicity to man if chronic exposure is allowed by continual waste disposal.

Amadi (2011) carried out geochemical assessment of the effect of Aladimma dumpsite on the nearby soil and shallow groundwater. Twenty (20) soils and thirty (30) groundwater samples were collected. The concentration of all the parameters analyzed were higher in soil than groundwater and heavy metals concentration vary as follows: Fe>Zn>Cu>Mn>Cr>Pb>As. This was attributed to high precipitation and subsequent weathering and leaching of metallic objects from the dumpsite into the shallow groundwater table. Water quality index (WQI) showed that the groundwater is poor in quality and factor analysis revealed five sources of groundwater pollution. He recommended reduction on waste incineration and modern sanitary landfills to replace the practice of open dumping.

Oki and Akana (2016) studied the geochemical characteristics of groundwater quality of Yenagoa. Fifteen (15) boreholes water samples were collected. pH, salinity, electrical conductivity, turbidity, total dissolved solids, alkalinity, hardness, nitrate, chloride, sulphate, bicarbonate, calcium, magnesium, sodium, potassium and iron were determined. Results showed that most results fell within acceptable World Health Organisation (WHO) limits for potable water except magnesium, pH in all BH samples were slightly acidic. Piper's trilinear plot showed

that Calcium and Chloride type water was predominant in the area. They concluded that the water from the area is good for domestic and industrial use. Although treatment is required in some areas where the results did not conform to standard before use to prevent health risks.

Edet *et al.*, (2014), studied the concentrations of toxic elements and total hydrocarbon in soils of Niger Delta region. Thirty-two (32) composite soil samples were analyzed for pH, EC, OC, grain size, THC, Cd, Co, Cr, Cu, Fe, Mn, Ni, Pb, V and Zn. Results showed that the average concentration of THC exceeded the limit in soils for crude oil processing areas in Nigeria. Cd in all the soil samples were higher than reported values for world soils. The average concentrations of Fe and Pb were higher than the background values but less than the average value for world soils suggesting that the elements were naturally present at low concentrations. Index of geoaccumulation (I-geo) values for all the samples corresponded to practically uncontaminated with the exception of THC (uncontaminated to moderately contamination) and Cd (moderately contaminated). They concluded that the main source of elements in Niger Delta is parent material, while increase in industrialization, especially, due to oil and gas related activities poses a significant impact on the distribution of some of these elements.

Akpoborie *et al.*, (2014), carried out a study on the urbanization and major ion hydrogeochemistry of the shallow aquifer at the Effurun-Warri metropolis, Nigeria using Piper plots and statistics, the result shows that groundwater is predominantly Ca+Mg+Na Chloride facies and that mixing and ion exchange processes control the dominant cation in space and thus at each specific locality. Leachates from many widely distributed and unregulated landfills and dumpsites have been identified as possibly the principal sources of major ion loading to groundwater. The ubiquitous on-site sewage treatment soak away pits also contribute major ions

to groundwater. These two sources are thus accountable for any observed local spikes in groundwater chloride content rather than sea water intrusion that had been previously suggested.

Nwankwoala and Udom (2011) carried out a study on the hydrochemical facies and ionic ratios of groundwater in Port- Harcourt city, Southern Nigeria. Groundwater samples were analyzed for their physical, chemical and microbiological properties. Besides of the major chemical compositions, ionic ratio (HCO_3/Cl , Na/Ca , Ca/Cl , Mg/Cl and Ca/SO_4) was used to delineate saline water intrusion. The analytical results present the abundance of the ions in the following order: $\text{Mg} > \text{Ca} > \text{Na} > \text{K} = \text{Cl} > \text{SO}_4 > \text{HCO}_3 > \text{NO}_3$. Chloride is the dominant anion found in the groundwater of the study area. Piper trilinear diagram for the study area showed that there was a mixture of two types of water with variable concentrations of major ions. These were $\text{Ca} - \text{Mg} - \text{Cl} - \text{SO}_4$ type and $\text{Na} + \text{K} - \text{Cl} - \text{SO}_4$ type water. The second water type was also influenced by NO_3 . This means that groundwater in the area is mainly made up of mixtures of earth alkaline and alkaline metals and predominantly $\text{Cl}^- - \text{SO}_4^{2-}$ water type. The quality of groundwater and the processes that control the concentration of major constituents is very necessary. They recommended that adequate hydro chemical knowledge be improved, in the study area, owing to the hydro geological heterogeneity in order to evaluate the hydrochemical characteristics, determine the ionic interactions as well as the hydrogeochemical facies distribution in the area.

Emmanuel *et al.*, (2015) examined the Compositional Characteristics and Industrial Assessment of the Cretaceous Clay Deposits within Southern Nigeria. The results from the study reveals that Physical parameters, Mineralogical and Chemical compositions suggest that the clay deposit could be exploited for ceramics, paint, pottery and refractory industries.

Onyekuru *et al.*, (2018) examined the Mineralogical and Geochemical properties of clay deposits in parts of Southern Nigeria. The results reveals that the clay samples analysis comparing with other reference clays and standard specifications, the clay deposits in the study area possess characteristics satisfactory for economic and some engineering purposes.

According to Benjamin *et al.*, (2019) Kaolin is one of the most important industrial minerals whose application is dependent on its structure and chemical composition. It was observed that major phases in the clay samples from the three different deposits are kaolinite, microcline, illite/mica, plagioclase/albite and quartz and the samples contain high concentration of plagioclase feldspar and quartz which permit its usage in the production of glass and iron industries. Also observed that some samples consist of kaolinite, a mixed layer of illite/mica, plagioclase, alkali feldspars, and albite which is necessary for producing mullite fibers in ceramic matrix at a temperature of around 1400°C and it is suitable in pigment production. The trace amount of some of the oxides such as K₂O, TiO₂, Fe₂O₃ and SnO₂ can help in the beneficiation process.

CHAPTER THREE

MATERIALS AND METHODOLOGY

3.1 MATERIALS

The materials (data) used for this study include one (1) Segy 3D seismic, seven (7) well header, seven (7) ASCII/Excel well deviation, seven (7) ASCII well logs and four (4) checkshot from TOK's well in the TOK's Field. The data were used to generate logs that consist of lithology log (gamma ray log), resistivity log and porosity logs (density, neutron, sonic). The data also included base map and information used on the sandstone tops and base. The measured depths (MD) were obtained.

Each of the studied wells comprised of several sandstones occurring at different depths and having different thicknesses that were evaluated to determine their reservoir potentials. The depths of occurrence of sands, their thicknesses as well as their correlation between TOK's wells are represented in the table of tops and bases of the sands in ftss (feet subsea).

Hampson Russell software was utilized for post-stack seismic inversion of TOKS Field, Niger Delta Basin, Nigeria.

3.2 METHODS

ANALYSIS OF WELL LOG

In the study of the well logs, the first step taken was to examine the gamma ray logs. The gamma ray logs delineate the reservoirs from the non-reservoirs and is used to estimate the shaliness of the reservoir rocks (the sands).

Low Gamma Ray (GR) values are linked to sands while high GR values indicate shale or clay. The GR is used in correlating reservoir between wells based on their signatures.

The resistivity logs were studied with the goal of identifying the hydrocarbon-bearing zones (pay zones) in the wells, which is indicated by a relatively high reading of the deep resistivity measurement. A section of the TOK's wells were correlated with the aid of the gamma ray and resistivity, logs. Areas showing low GR readings and high resistivity values were easily identified as possible hydrocarbon reservoirs. Similar signatures were correlated as representing the continuity of the unit or formation.

3.3 LITHOLOGICAL DELINEATION

The established lithologies encountered by each well were identified using the Gamma ray log. Formation tops and bottoms (Upper and lower limits) of the identified sandstone was obtained by characterizing textural parameters and recorded. In virtually all the wells, the established lithologic sequences was that of sandstone and shale though sandstone was dominant. Several thin intercalations of shale were observed from the log signatures though a few thick shale layer exist. The reservoir sandstone existed from beyond 1500ft depths in the wells and ranged in thickness at different intervals that were alternating with shales.

3.4 PETROPHYSICAL PARAMETERS FOR RESERVOIR EVALUATION

3.4.1 SHALE VOLUME (V_{SH})

The shale volume expressed as a decimal fraction is a measure of the amount of clay present in a particular formation. To determine the volume of shale and / or clay; the GR log assumes that the clean zones do not contain radioactive minerals, i.e., granite wash, micaceous

sands, radioactive carbonates. The volume of shale (gamma ray index) is calculated from the gamma ray log using the linear equation from schlumberger (1974):

$$= \frac{GR - GR_{max}}{GR_{shale} - GR_{matrix}}$$

Volume of shale from GR was computed using the Larinov Equation for Tertiary rocks

$$VSH_{Larinov} = 0.083 * (2^{(3.7*GR_{index})} - 1)$$

Or

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

Where IGR = Gamma Ray Index (volume of shale content)

GRlog = Gamma Ray reading from formation (measured log)

GRmin = Gamma Ray minimum (clean sand)

GRmax = Gamma Ray maximum (shale log value)

The shale volume is calculated in order to correct for its effect of the porosity of sandstones (i.e. where it is present).

3.4.2 POROSITY

Porosity is the ratio of void spaces present in the formation to the total rock volume corrected for shale.

Density log-derived porosity

Density measurements are used primarily to calculate formation porosity when lithology is known. When combined with other porosity logs, density measurements are used for the detection of gas, evaluation of shaly sands and lithology identification. Compensated density tools measure the in-situ bulk formation density, ρ_b , recorded in (g/cm^3). Formation porosity is determined by assuming the fluid density in the pore space and the matrix density contribute to the total bulk density in an additive manner (Asquith and Gibson, 1982).

Porosity was estimated using neutron-density logs using;

Matrix Density = $2.65\text{g}/\text{cm}^3$

Fluid density = $1\text{g}/\text{cm}^3$

$(\phi D + \phi N) / 2$, for oil & water zones

Effective porosity

Effective porosity is a measure of the amount of void spaces that are interconnected, and so able to transmit fluids. Isolated pores and pore volume occupied by adsorbed water are excluded from this definition. The neutron – density log and shale volume was used to calculate the effective porosity.

3.4.3 WATER SATURATION FOR THE INVADED ZONE (S_w)

Water saturation indicates the fraction of the total space that is occupied by formation water. All water saturation determinations from resistivity logs in clean (uninvaded) formations with homogeneous intergranular porosity are based on Archie's water saturation equation or variation thereof.

Water saturation was estimated using the Archie since the sands were relatively clean.

$$S_w^n = \frac{R_w}{(\Phi^m \times R_t)}$$

where:

S_w = water saturation of the uninvasion zone

n = saturation exponent,

R_w = formation water resistivity at formation temperature

Φ = porosity

m = cementation exponent,

R_t = true resistivity of the formation, corrected for invasion, borehole, thin bed, and other effects.

3.5 SURFACE ATTRIBUTE

Root-mean-square (RMS) as a surface attribute was extracted from two-time surfaces mapped, to aid the identification of hydrocarbon prospects on the surface generated.

3.6 SEISMIC INVERSION

The inversion workflow was carried out using the following procedure: selection of the post-stack seismic and interpreted horizons, extraction of statistical wavelet, selection of the well

to be used, correlation of the wells, building the initial model, inversion analysis and generation of the 3-D acoustic impedance cube.

3.7 POST-STACK SEISMIC INVERSION WORKFLOW OF TOKS FIELD

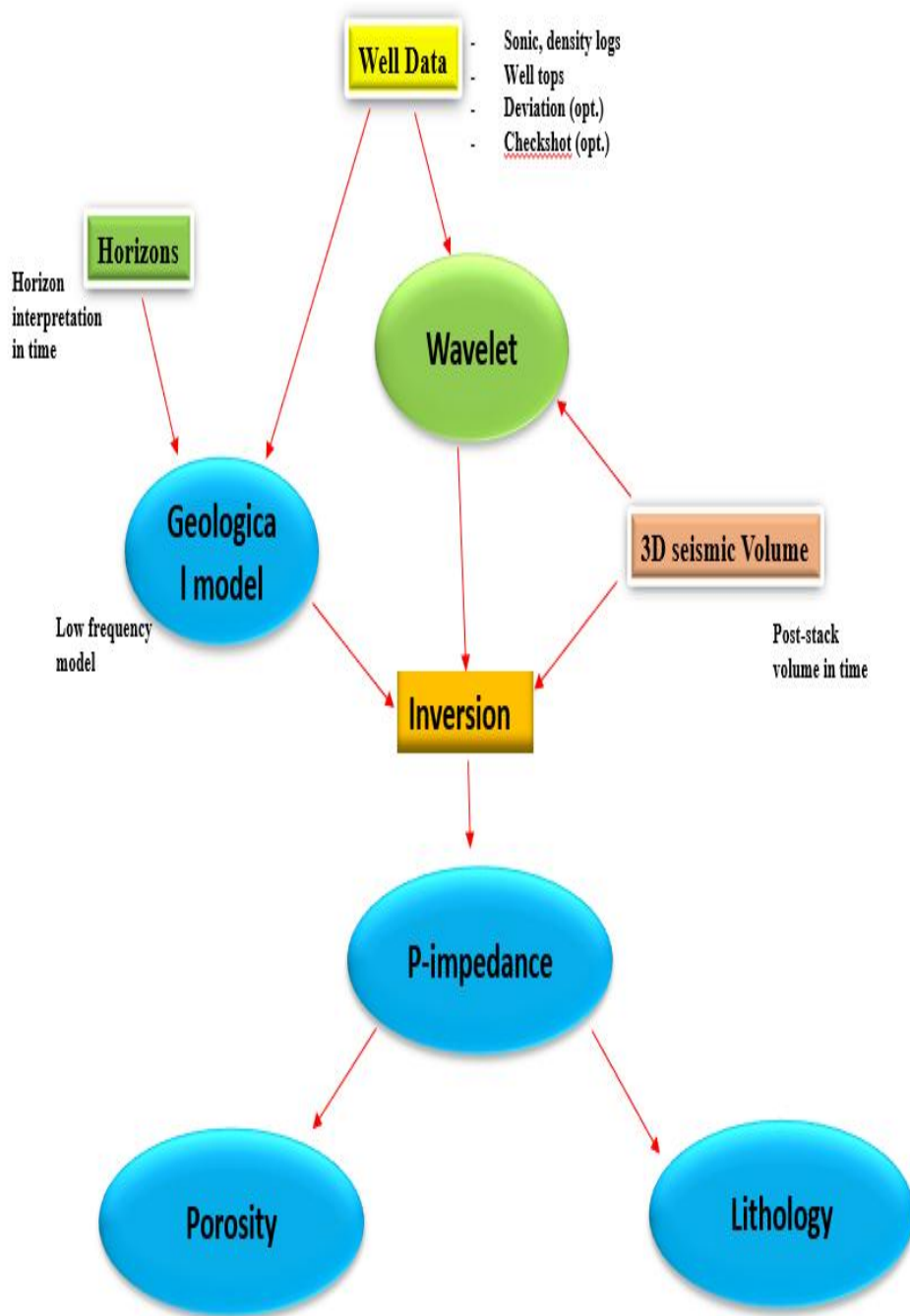


Fig. 3.1: Post-Stack Seismic Inversion Workflow of TOKS Field

3.7.1 Well Logs Importation

The Hampson Russell software was utilized for post-stack seismic inversion of TOKS Field and well logs were imported to provide essential petrophysical inputs for calibration and inversion modeling. The imported logs include gamma ray (GR) log, resistivity (RT) log, density (RHOB) log, neutron porosity (NPHI) log, and compressional sonic (DT) logs. Prior to importation, the logs were subjected to thorough quality control, including despiking, depth matching, and correction of washout or bad-hole zones to ensure data integrity. The checkshot data were used to generate a time–depth relationship, aligning the well data with the seismic reference time. The compressional sonic and density logs were combined to compute the acoustic impedance (AI), which served as a key input for wavelet estimation and inversion calibration.

Import Files Well Settings Log Settings

Start Well Index 1 Number of items to show (1/1): 50

File Name	Well Name From File	Destination Well Name	UWI (option)	X	Y	Units	HRS Well Type	KB Elev.	Surface Elev.	Elev. Units
1 TOKS Well 15.LAS	TOKS WELL 15	TOKS WELL 15	Unknown	0.00	0.00	m	UNSPECIFIED	0.00	0.00	m

Seismic Reference Datum

<Same As Surface>
 Seismic Reference Datum Elevation: 0 m

Seismic Replacement Velocity: 0 m/s

Replace Well Name with UWI

Fig.3.2: Well log Importation Process

The conditioned logs were exported in LAS format and loaded into Hampson Russell's Well module, where they were synchronized with the seismic volume for wavelet extraction and low-frequency model building. This process ensured an accurate correlation between seismic amplitudes and reservoir properties. The reliability of the imported well data played a critical role in constraining the inversion outputs, improving the prediction of lithofacies and fluid distribution, and ultimately guiding optimal well placement in the undrilled location.

3.7.2 Petrophysical Well Logs Analysis

The petrophysical well logs analysis for post-stack seismic inversion of TOKS Field using Hampson Russell software, were carried out to characterize the reservoir and provide key inputs for wavelet extraction, low-frequency model generation, and inversion calibration. The analyzed logs included gamma ray (GR), density (RHOB), compressional P-wave sonic (DT), neutron porosity (NPHI), and resistivity (RT) logs. The data generated are presented in chapter four (4) as results and discussion.

CHAPTER FOUR

RESULTS AND DISCUSSION

4.1 PETROPHYSICAL PROPERTIES

The average values of the petrophysical parameters for all sandstone reservoir identified in all TOKS wells, TOKS 14, TOKS 15, TOKS 16, TOKS 17, TOKS 18, TOKS 19 and TOKS 51 are presented in Table 4.1, Table 4.2, Table 4.3, Table 4.4, Table 4.5, Table 4.6, and Table 4.7. The log data for each of the studied wells and the calculated values of the volume of shale (VSH), porosity (PHIT), water saturation and Net to gross are shown below.

The reservoir thickness of TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 are presented in Table 4.1, Table 4.2, Table 4.3, Table 4.4, Table 4.5, Table 4.6, and Table 4.7 respectively. The petrophysical parameters of the reservoir at different wells, TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 for TOKS 1000 and TOKS 3000 are presented in Table 4.8, Table 4.9 respectively. The geological cross section of well tops (well correlation) and the petrophysical evaluation of wells whose log signature penetrated the reservoirs of interests are presented in Figure 4.1, Figure 4.2, Figure 4.3 and Figure 4.4 respectively.

Table 4.1: Reservoir thickness of TOKS Well 14, TOK's Field

Reservoir	1	2	3	4	5
Depth (m)	2180.6 – 2190	2190.2 – 2190.7	2190.8 – 2200.2	2200.7 – 2220	2240.2 – 2220.5
Thickness (m)	9.4	0.5	9.4	19.3	19.7
Fluid Present	Hydrocarbon	Hydrocarbon	Hydrocarbon	Hydrocarbon	Hydrocarbon

Table 4.2: Reservoir thickness of TOKS Well 15, TOK's Field

Reservoir	1	2	3
Depth (m)	2222.2 – 2232.2	2280.3 – 2290.6	2310 – 2324.1
Thickness (m)	10	10.3	14.1
Fluid Present	Hydrocarbon	Hydrocarbon	Hydrocarbon

Table 4.3: Reservoir thickness of TOKS Well 16, TOK's Field

Reservoir	1	2
Depth (m)	2200.7 – 2220.3	2280 – 2290.2
Thickness (m)	19.6	10.2
Fluid Present	Hydrocarbon	Hydrocarbon

Table 4.4: Reservoir thickness of TOKS Well 17, TOK's Field

Reservoir	1	2	3	4	5	6	7
Depth (m)	2039.2 – 2050	2050.5 – 2060.1	2060.3 – 2070.1	2070.3 – 2080.3	2090 – 2100.2	2110 – 2120.6	2130 – 2150.7
Thickness (m)	10.8	9.5	9.8	9.7	10.2	10.6	20.7

Table 4.5: Reservoir thickness of TOKS Well 18, TOK's Field

Reservoir	1	2	3	4
Depth (m)	2220 – 2220.8	2230 – 2240	2250 – 2260	2290.2 – 2300.5
Thickness (m)	0.8	10	10	10.3

Table 4.6: Reservoir thickness of TOKS Well 19, TOK's Field

Reservoir	1	2	3	4	5	6	7
Depth (m)	1921.3 – 1930.5	1930.6 – 1940.5	1960 – 1970	1970.4 – 1980.1	1990 – 1990.9	2000 – 2010	2020.4 – 2020.6
Thickness (m)	9.2	9.9	10	9.7	0.9	10	0.2

Table 4.7: Reservoir thickness of TOKS Well 51, TOK's Field

Reservoir	1	2	3
Depth (m)	2440 – 2450.2	2470 – 2490	2490.3 – 2507.8
Thickness (m)	10.2	20	17.5

Table 4.8: PETROPHYSICAL PARAMETERS OF THE RESERVOIR AT DIFFERENT WELL (TOKS 1000)

WELL NAME	POROSITY	WATER SATURATION	SHALE VOLUME	NET TO GROSS
TOKS 14	0.3054	0.2750	0.05	0.95
TOKS 15	0.3103	0.2645	0.05	0.95
TOKS 16	0.3042	0.2788	0.05	0.95
TOKS 17	0.3252	0.2521	0.04	0.96
TOKS 18	0.3055	0.2684	0.04	0.96
TOKS 19	0.3108	0.2638	0.05	0.95
TOKS 51	0.3857	0.2972	0.07	0.93

Table 4.9: PETROPHYSICAL PARAMETERS OF THE RESERVOIR AT DIFFERENT WELL (TOKS 3000)

WELL NAME	POROSITY	WATER SATURATION	SHALE VOLUME	NET TO GROSS
TOKS 14	0.3491	0.2349	0.08	0.92
TOKS 15	0.3121	0.2627	0.05	0.95
TOKS 16	0.3135	0.2615	0.05	0.95
TOKS 17	0.2993	0.2741	0.04	0.96
TOKS 18	0.3353	0.2446	0.08	0.92
TOKS 19	0.2881	0.2846	0.05	0.95
TOKS 51				

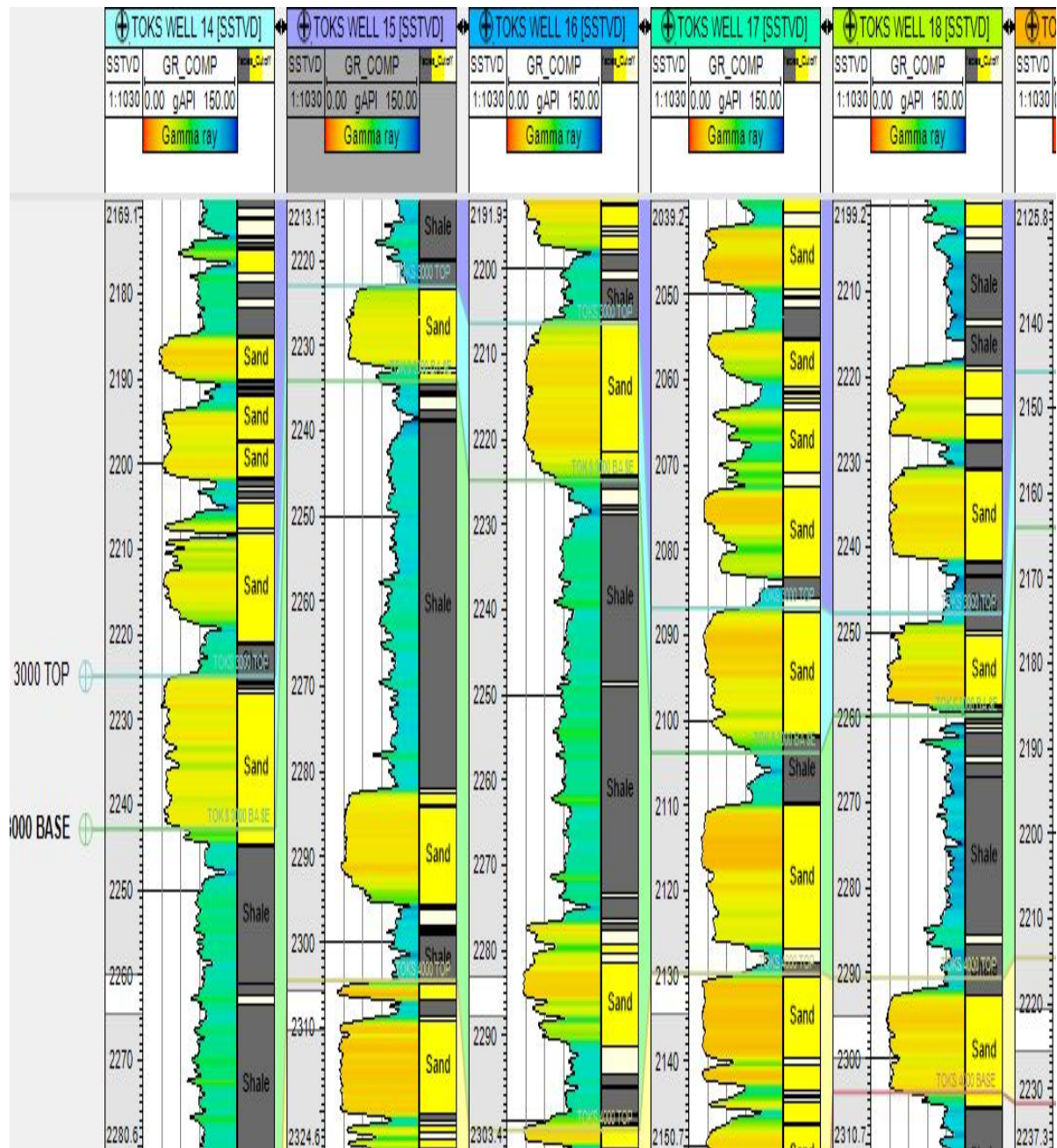


Fig. 4.1: Geological Cross Section of Well Tops – Well Correlation

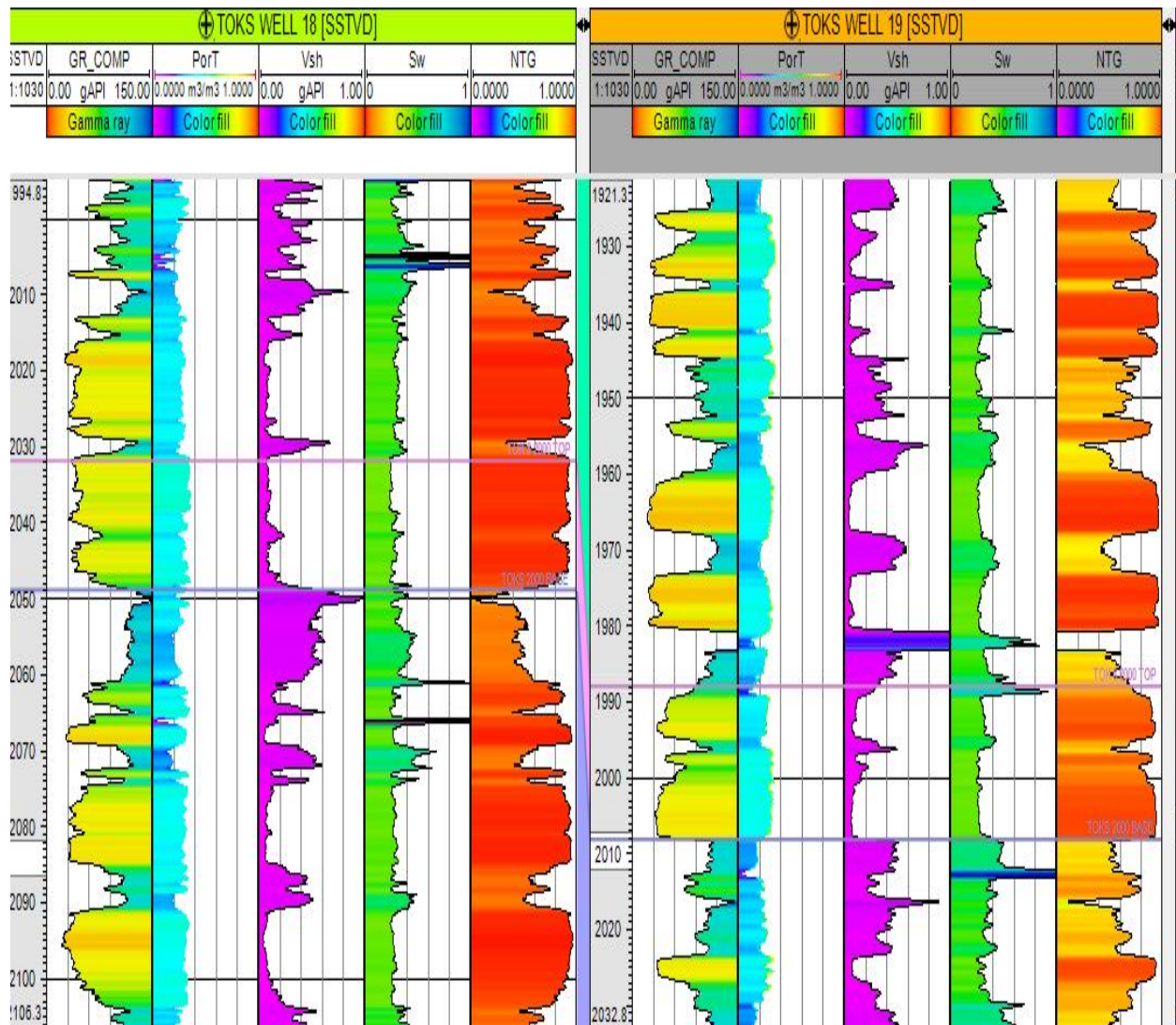


Fig.4.2: Geological Cross Section of Well Tops – Well Correlation

**TABLE 4.10: GEOLOGICAL WELL CORRELATION POINTS OF THE RESERVOIR
AT DIFFERENT WELL FOR TOKS 1000 AND TOKS 3000**

Reservoir	Ft	TOKS	TOKS	TOKS	TOKS	TOKS	TOKS	TOKS
Sands	sstvd	Well 14	Well 15	Well 16	Well 17	Well 18	Well 19	Well 51
TOKS 1000	TOP	1910	1955	1935	1782	1942	1870	
TOKS 1000	BASE	1930	1980	1960	1880	1970	1895	
TOKS 3000	TOP	2225	2223	2208	2089	2250		
TOKS 3000	BASE	2242	2233	2233	2103	2260		

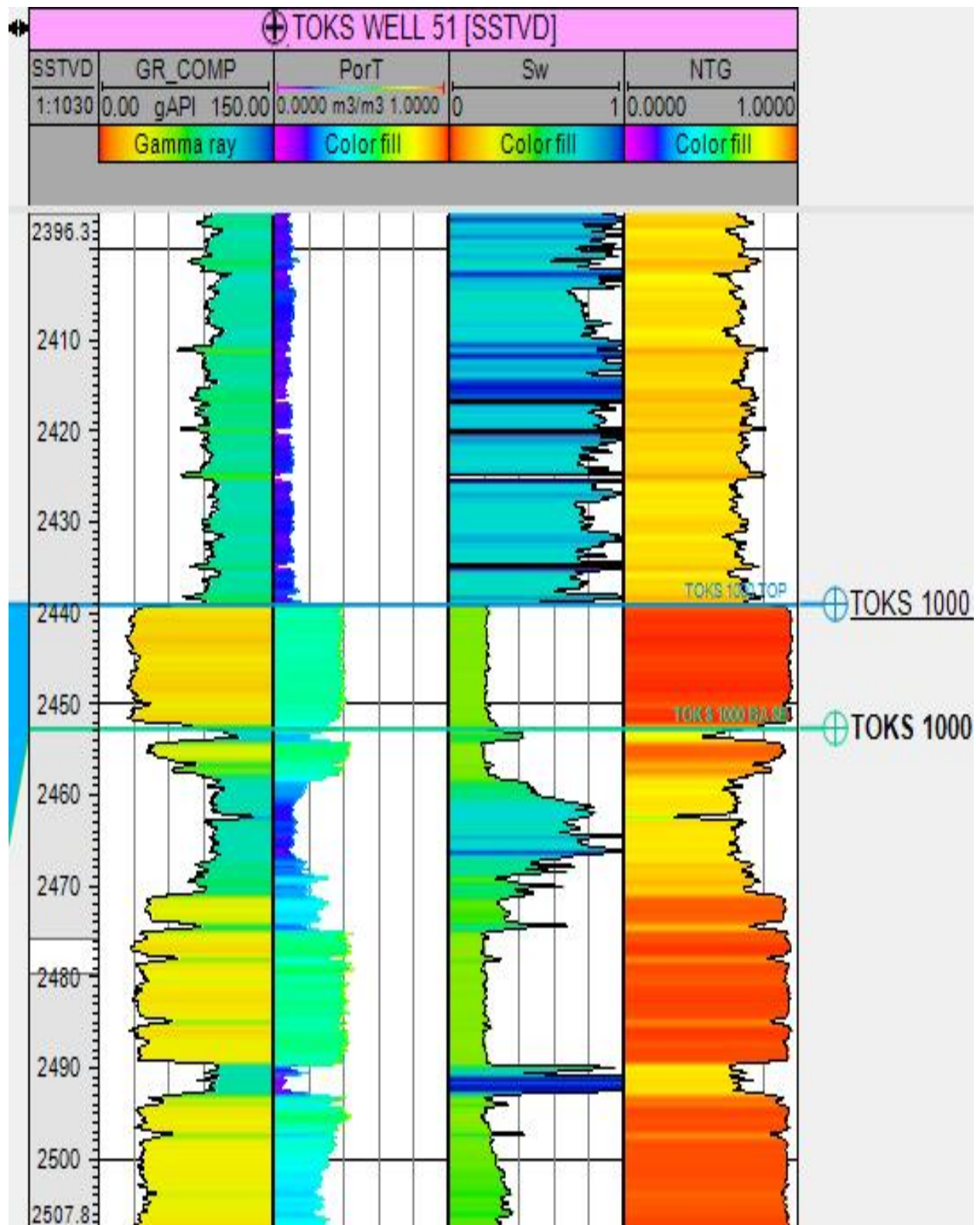


Fig.4.3: Geological Cross Section of Well Tops – Well Correlation

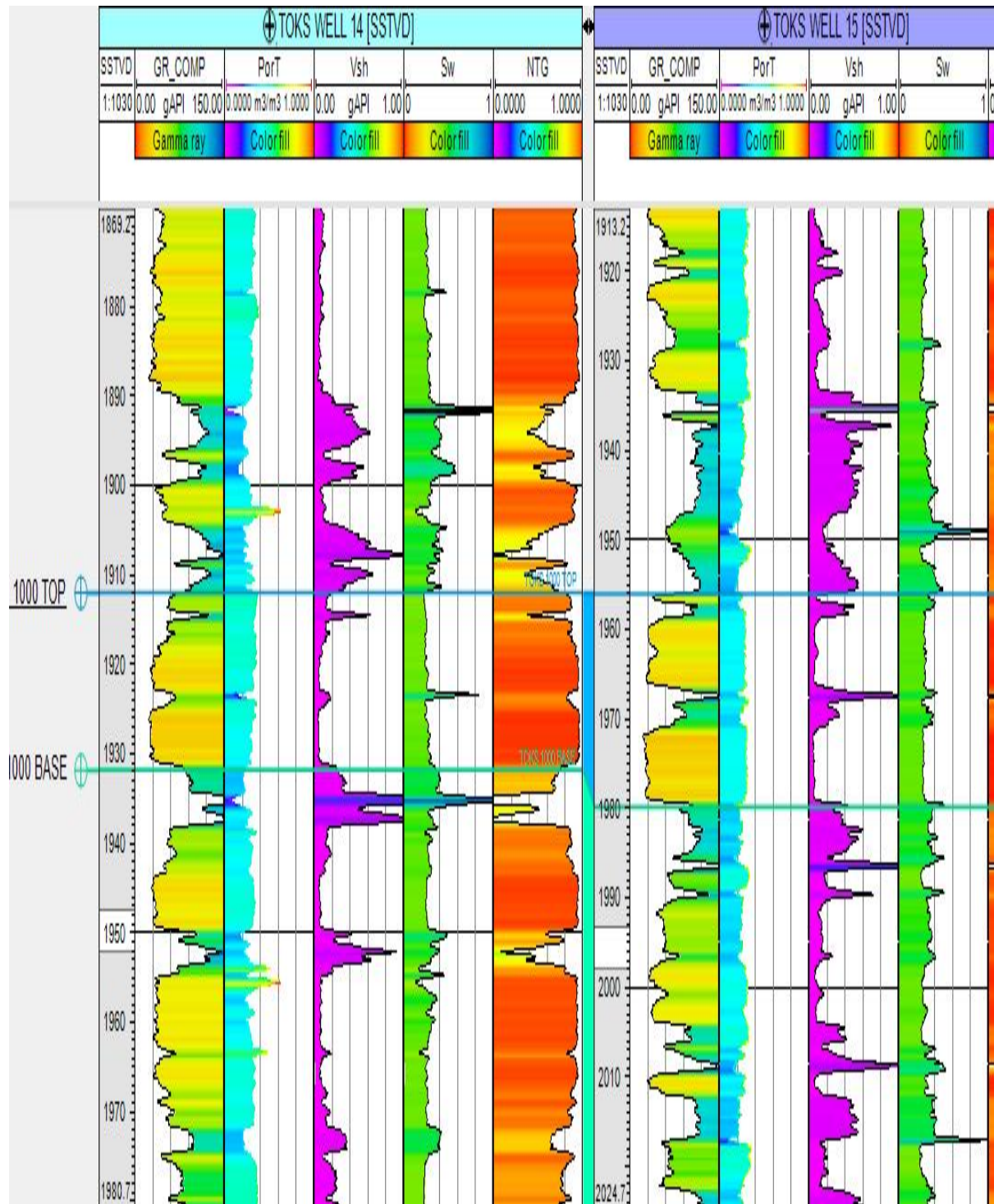


Fig. 4.4: Petrophysical evaluation of wells whose log signature penetrated the reservoirs of interests

For the purpose of these interpretation all the seven (7) wells were used due to good 2readings generated by tools during logging. All hydrocarbon bearing reservoirs were logged in the wells.

4.1.1 Discussion of Petrophysical Parameters

4.1.1.1 TOKS WELL 14

The volume of shale, porosity, water saturation and Net to gross in TOKS Well 14 was determined by calculation respectively. The values were further produced on a log format for the easy identification of hydrocarbon potential reservoirs. The neutron – density porosity values obtained were corrected for the shale effect to determine the accurate value for the effective porosity. Five (5) hydrocarbon sandstone bearing reservoirs were identified in the well section of TOKS 14, these were all identified at different thicknesses that range from 0.5m – 19.7m with a net thickness of 58. 3m and the well contain fine grained rocks with fewer shale volumes, also water saturation in this reservoir were less than sixty percentage. Hence, the well reservoir will produce large amounts of hydrocarbon in its pore volume that will be accompanied by little or no water. The net – to – gross (NTG) for the well section at TOKS 1000 is 0.95; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. Also, the net – to – gross (NTG) for the well section at TOKS 3000 is 0.92; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. The volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 5%, this is considerably low shale volume within reservoir in the well section for TOKS 1000 while the volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 8%, this is also considerably low shale volume within reservoir in the well section for

TOKS 3000. The water saturation in a reservoir is relative as an increase in water saturation will result in a decrease in hydrocarbon saturation, the water saturation in the studied well section 27.5% for TOKS 1000, this reflect a prolific reservoir and while the water saturation in the studied well section is 23.5% for TOKS 3000, also reflecting a prolific reservoir. The porosity values which is the available pore space in the reservoir in the well section is 30.5% for TOKS 1000, this is for good to excellent reservoir quality while the porosity for well section is 34.9 % for TOKS 3000, this is also for good to excellent reservoir quality. Careful observation of the fluid impact determination cross plot shows that the sandstones that make up the reservoirs contained less amount of gas/light hydrocarbon with evidence of no bad hole condition.

4.1.1.2 TOKS WELL 15

The volume of shale, porosity, water saturation and Net to gross in TOKS Well 15 was also determined by calculation respectively. The values were further produced on a log format for the easy identification of hydrocarbon potential reservoirs. The neutron – density porosity values obtained were corrected for the shale effect to determine the accurate value for the effective porosity. Three (3) hydrocarbon sandstone bearing reservoirs were identified in the well section of TOKS 15, these were all identified at different thicknesses that range from 10m – 14.1m with a net thickness of 34.4m and the well contain fine grained rocks with fewer shale volumes, also water saturation in this reservoir were less than sixty percentage. Hence, the well reservoir will produce large amounts of hydrocarbon in its pore volume that will be accompanied by little or no water. The net – to – gross (NTG) for the well section at TOKS 1000 is 0.95; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. Also, the net – to – gross (NTG) for the well section at TOKS 3000 is 0.95; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness.

The volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 5%, this is considerably low shale volume within reservoir in the well section for TOKS 1000 while the volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 5%, this is also considerably low shale volume within reservoir in the well section for TOKS 3000. The water saturation in a reservoir is relative as an increase in water saturation will result in a decrease in hydrocarbon saturation, the water saturation in the studied well section 26.5% for TOKS 1000, this reflect a prolific reservoir and while the water saturation in the studied well section is 26.3% for TOKS 3000, also reflecting a prolific reservoir. The porosity values which is the available pore space in the reservoir in the well section is 31.0% for TOKS 1000, this is for good to excellent reservoir quality while the porosity for well section is 31.2% for TOKS 3000, this is also for good to excellent reservoir quality. Careful observation of the fluid impact determination cross plot shows that the sandstones that make up the reservoirs contained less amount of gas/light hydrocarbon with evidence of no bad hole condition.

4.1.1.3 TOKS WELL 16

The volume of shale, porosity, water saturation and Net to gross in TOKS Well 16 was also determined by calculation respectively. The values were further produced on a log format for the easy identification of hydrocarbon potential reservoirs. The neutron – density porosity values obtained were corrected for the shale effect to determine the accurate value for the effective porosity. Two (2) hydrocarbon sandstone bearing reservoirs were identified in the well section of TOKS 16, these were all identified at different thicknesses that range from 10.2m – 19.6m with a net thickness of 29.8m and the well contain fine grained rocks with fewer shale volumes, also water saturation in this reservoir were less than sixty percentage. Hence, the well reservoir will produce large amounts of hydrocarbon in its pore volume that will be accompanied

by little or no water. The net – to – gross (NTG) for the well section at TOKS 1000 is 0.95; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. Also, the net – to – gross (NTG) for the well section at TOKS 3000 is 0.95; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. The volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 5%, this is considerably low shale volume within reservoir in the well section for TOKS 1000 while the volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 5%, this is also considerably low shale volume within reservoir in the well section for TOKS 3000. The water saturation in a reservoir is relative as an increase in water saturation will result in a decrease in hydrocarbon saturation, the water saturation in the studied well section 27.9% for TOKS 1000, this reflect a prolific reservoir and while the water saturation in the studied well section is 26.2% for TOKS 3000, also reflecting a prolific reservoir. The porosity values which is the available pore space in the reservoir in the well section is 30.4% for TOKS 1000, this is for good to excellent reservoir quality while the porosity for well section is 31.4% for TOKS 3000, this is also for good to excellent reservoir quality. Careful observation of the fluid impact determination cross plot shows that the sandstones that make up the reservoirs contained less amount of gas/light hydrocarbon with evidence of no bad hole condition.

4.1.1.4 TOKS WELL 17

The volume of shale, porosity, water saturation and Net to gross in TOKS Well 17 was also determined by calculation respectively. The values were further produced on a log format for the easy identification of hydrocarbon potential reservoirs. The neutron – density porosity values obtained were corrected for the shale effect to determine the accurate value for the effective porosity. Seven (7) hydrocarbon sandstone bearing reservoirs were identified in the

well section of TOKS 17, these were all identified at different thicknesses that range from 9.5m – 20.7m with a net thickness of 81. 3m and the well contain fine grained rocks with fewer shale volumes, also water saturation in this reservoir were less than sixty percentage. Hence, the well reservoir will produce large amounts of hydrocarbon in its pore volume that will be accompanied by little or no water. The net – to – gross (NTG) for the well section at TOKS 1000 is 0.96; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. Also, the net – to – gross (NTG) for the well section at TOKS 3000 is 0.96; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. The volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 4%, this is considerably low shale volume within reservoir in the well section for TOKS 1000 while the volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 4%, this is also considerably low shale volume within reservoir in the well section for TOKS 3000. The water saturation in a reservoir is relative as an increase in water saturation will result in a decrease in hydrocarbon saturation, the water saturation in the studied well section 25.2% for both TOKS 1000 and TOKS 3000, also reflecting a prolific reservoir. The porosity values which is the available pore space in the reservoir in the well section is 32.5% for both TOKS 1000 and TOKS 3000, this percentage is for good to excellent reservoir quality. Careful observation of the fluid impact determination cross plot shows that the sandstones that make up the reservoirs contained less amount of gas/light hydrocarbon with evidence of no bad hole condition.

4.1.1.5 TOKS WELL 18

The volume of shale, porosity, water saturation and Net to gross in TOKS Well 18 was also determined by calculation respectively. The values were further produced on a log format

for the easy identification of hydrocarbon potential reservoirs. The neutron – density porosity values obtained were corrected for the shale effect to determine the accurate value for the effective porosity. Four (4) hydrocarbon sandstone bearing reservoirs were identified in the well section of TOKS 18, these were all identified at different thicknesses that range from 0.8m – 10.3m with a net thickness of 31.1m and the well contain fine grained rocks with fewer shale volumes, also water saturation in this reservoir were less than sixty percentage. Hence, the well reservoir will produce large amounts of hydrocarbon in its pore volume that will be accompanied by little or no water. The net – to – gross (NTG) for the well section at TOKS 1000 is 0.96; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. Also, the net – to – gross (NTG) for the well section at TOKS 3000 is 0.92; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. The volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 4%, this is considerably low shale volume within reservoir in the well section for TOKS 1000 while the volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 8%, this is also considerably low shale volume within reservoir in the well section for TOKS 3000. The water saturation in a reservoir is relative as an increase in water saturation will result in a decrease in hydrocarbon saturation, the water saturation in the studied well section 26.8% for TOKS 1000, this reflect a prolific reservoir and while the water saturation in the studied well section is 24.5% for TOKS 3000, also reflecting a prolific reservoir. The porosity values which is the available pore space in the reservoir in the well section is 30.5% for TOKS 1000, this is for good to excellent reservoir quality while the porosity for well section is 33.5% for TOKS 3000, this is also for good to excellent reservoir quality. Careful observation of the

fluid impact determination cross plot shows that the sandstones that make up the reservoirs contained less amount of gas/light hydrocarbon with evidence of no bad hole condition.

4.1.1.6 TOKS WELL 19

The volume of shale, porosity, water saturation and Net to gross in TOKS Well 19 was also determined by calculation respectively. The values were further produced on a log format for the easy identification of hydrocarbon potential reservoirs. The neutron – density porosity values obtained were corrected for the shale effect to determine the accurate value for the effective porosity. Seven (7) hydrocarbon sandstone bearing reservoirs were identified in the well section of TOKS 19, these were all identified at different thicknesses that range from 0.2m – 10m with a net thickness of 49.9m and the well contain fine grained rocks with fewer shale volumes, also water saturation in this reservoir were less than sixty percentage. Hence, the well reservoir will produce large amounts of hydrocarbon in its pore volume that will be accompanied by little or no water. The net – to – gross (NTG) for the well section at TOKS 1000 is 0.95; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. Also, the net – to – gross (NTG) for the well section at TOKS 3000 is 0.92; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. The volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 5%, this is considerably low shale volume within reservoir in the well section for TOKS 1000 while the volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 5%, this is also considerably low shale volume within reservoir in the well section for TOKS 3000. The water saturation in a reservoir is relative as an increase in water saturation will result in a decrease in hydrocarbon saturation, the water saturation in the studied well section 26.4% for TOKS 1000, this reflect a prolific reservoir and while the water saturation in the

studied well section is 28.5% for TOKS 3000, also reflecting a prolific reservoir. The porosity values which is the available pore space in the reservoir in the well section is 31.1% for TOKS 1000, this is for good to excellent reservoir quality while the porosity for well section is 28.8 % for TOKS 3000, this is also for good to excellent reservoir quality. Careful observation of the fluid impact determination cross plot shows that the sandstones that make up the reservoirs contained less amount of gas/light hydrocarbon with evidence of no bad hole condition.

4.1.1.7 TOKS WELL 51

The volume of shale, porosity, water saturation and Net to gross in TOKS Well 16 was also determined by calculation respectively. The values were further produced on a log format for the easy identification of hydrocarbon potential reservoirs. The neutron – density porosity values obtained were corrected for the shale effect to determine the accurate value for the effective porosity. Three (3) hydrocarbon sandstone bearing reservoirs were identified in the well section of TOKS 51, these were all identified at different thicknesses that range from 10.2m – 20m with a net thickness of 47.7m and the well contain fine grained rocks with fewer shale volumes, also water saturation in this reservoir were less than sixty percentage. Hence, the well reservoir will produce large amounts of hydrocarbon in its pore volume that will be accompanied by little or no water. The net – to – gross (NTG) for the well section at TOKS 1000 is 0.93; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. The volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 5%, this is considerably low shale volume within reservoir in the well section for TOKS 1000. The water saturation in a reservoir is relative as an increase in water saturation will result in a decrease in hydrocarbon saturation, the water saturation in the studied well section 29.7% for TOKS 1000, this reflect a prolific reservoir. The porosity values which is the available

pore space in the reservoir in the well section is 38.6% for TOKS 1000, this is for good to excellent reservoir quality. Careful observation of the fluid impact determination cross plot shows that the sandstones that make up the reservoirs contained less amount of gas/light hydrocarbon with evidence of no bad hole condition.

4.2 LITHOLOGICAL DELINEATION

Lithologies

The established lithologies encountered by each well were identified using the Gamma ray log. Formation tops and bottoms (Upper and Lower Limits) of the identified sandstone was obtained and recorded. The lithologies of TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 for TOKS 1000 were largely of sandstone lithology with few thin intercalations of shale observed in the log signatures. The reservoir sandstone existed from 1700ft depth in the wells and ranges in thickness at different intervals that were alternating with shales.

The lithologies of TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 for TOKS 3000 were largely of sandstone lithology with few thick intercalations of shale observed in the log signatures. The reservoir sandstone existed from 2000ft depth in the wells and ranges in thickness at different intervals that were alternating with shales. In virtually all the wells of the TOKS Field in Niger Delta Nigeria, the established lithologic sequence using the Gamma ray log were that of sandstone and shale though sandstone lithologies were dominant and this is in consistence with the work of Anyim (2010) and Osinowo *et al.*, (2018).

Reservoir Thickness Maps (Isochore) of the Wells Reservoir Zones

Isochore maps, also known as thickness maps are used to visualize the true thickness of a reservoir zone across a field. They are constructed by plotting contours that connect points of equal thickness of a specific rock unit, such as a reservoir zones would show the variations in thickness across the field, aiding in understanding reservoir geometry and predicting hydrocarbon distribution.

The reservoir thickness maps (isochore) of TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 for TOKS 1000 reservoir zone are presented in figure 4.5, figure 4.6, figure 4.7, figure 4.8, figure 4.9 and figure 4.10 respectively.

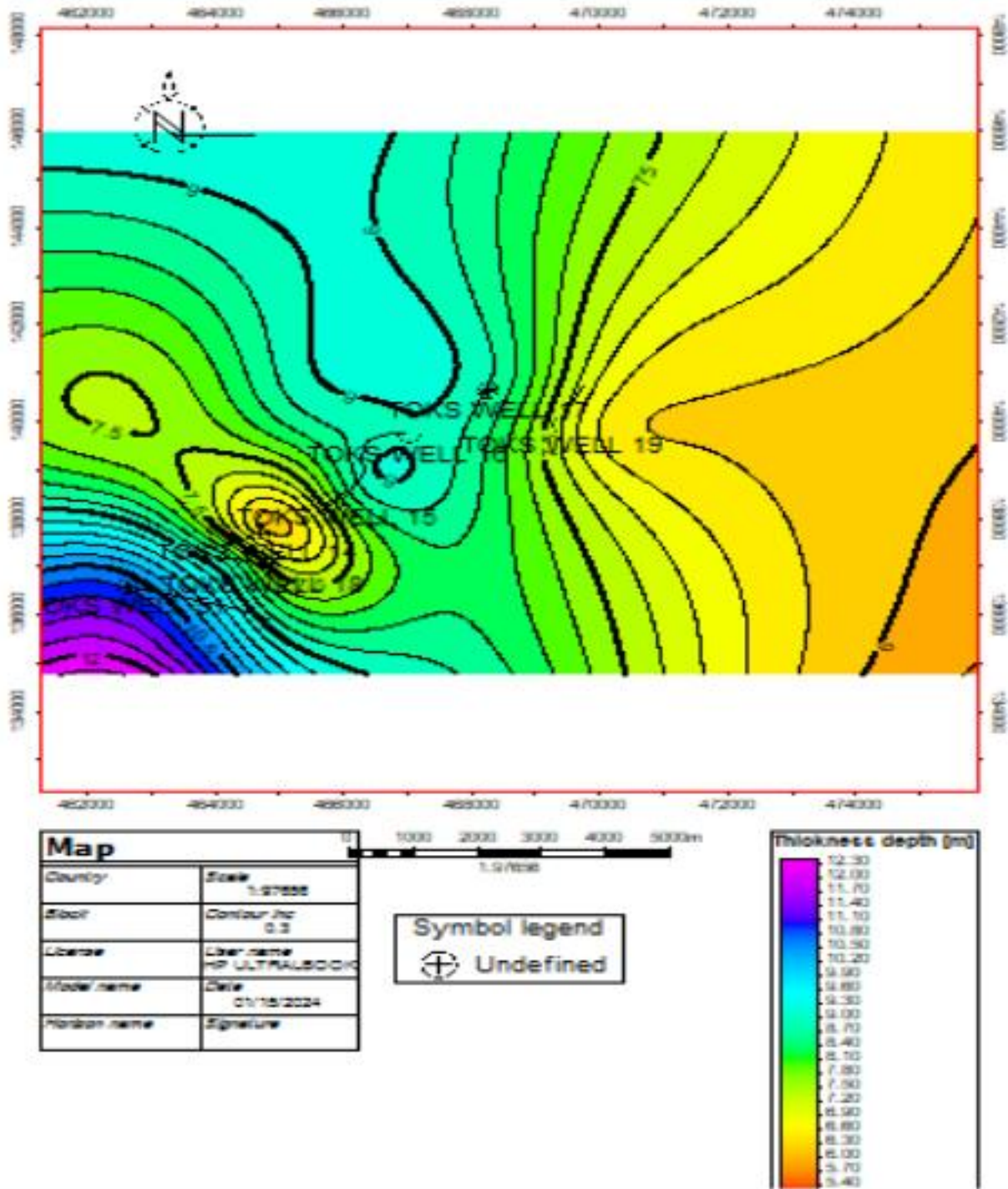


Fig. 4.5: Isochore map showing the thickness of TOKS 1000 reservoir zone

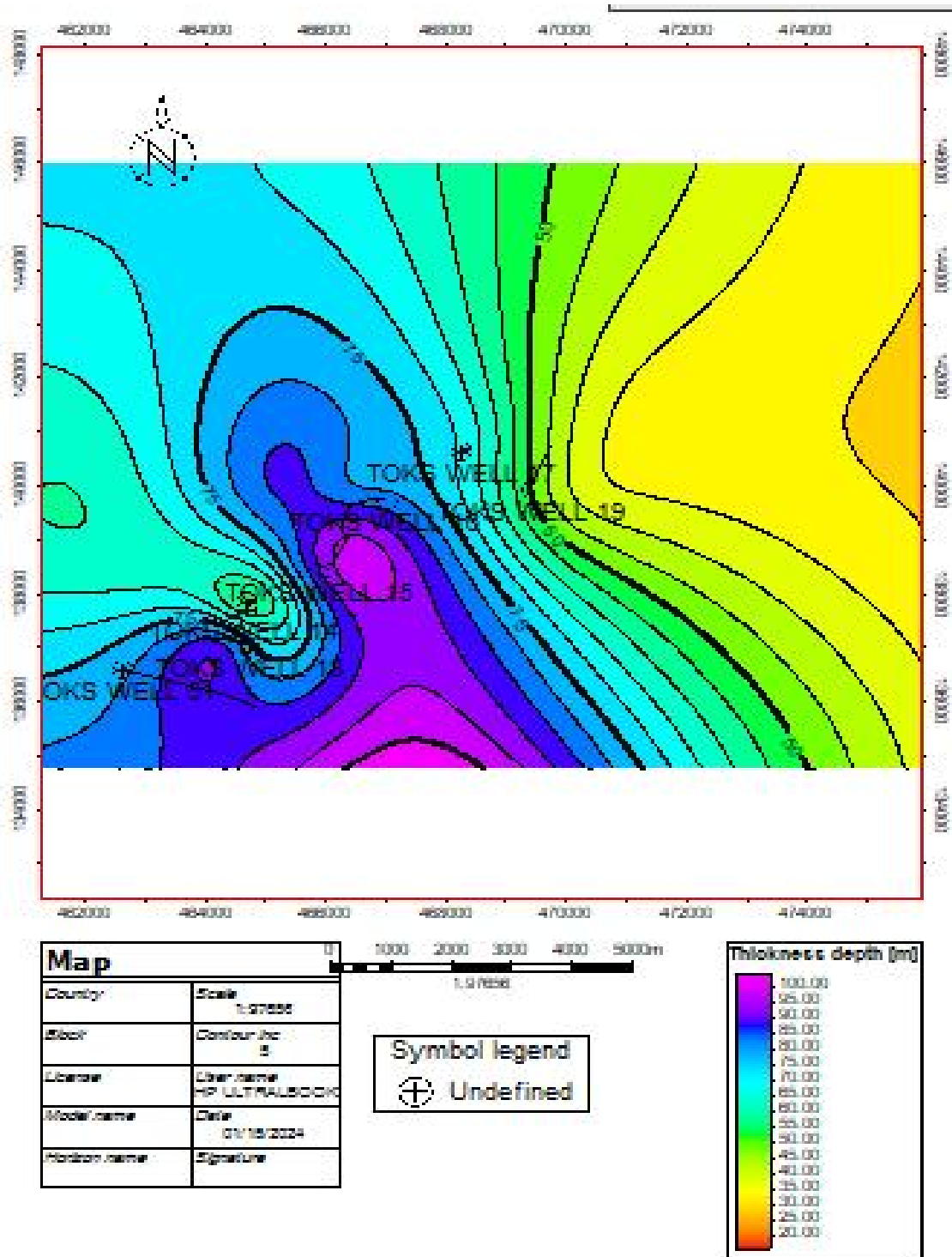


Fig. 4.6: Isochore map showing the thickness of TOKS 2000 reservoir zone

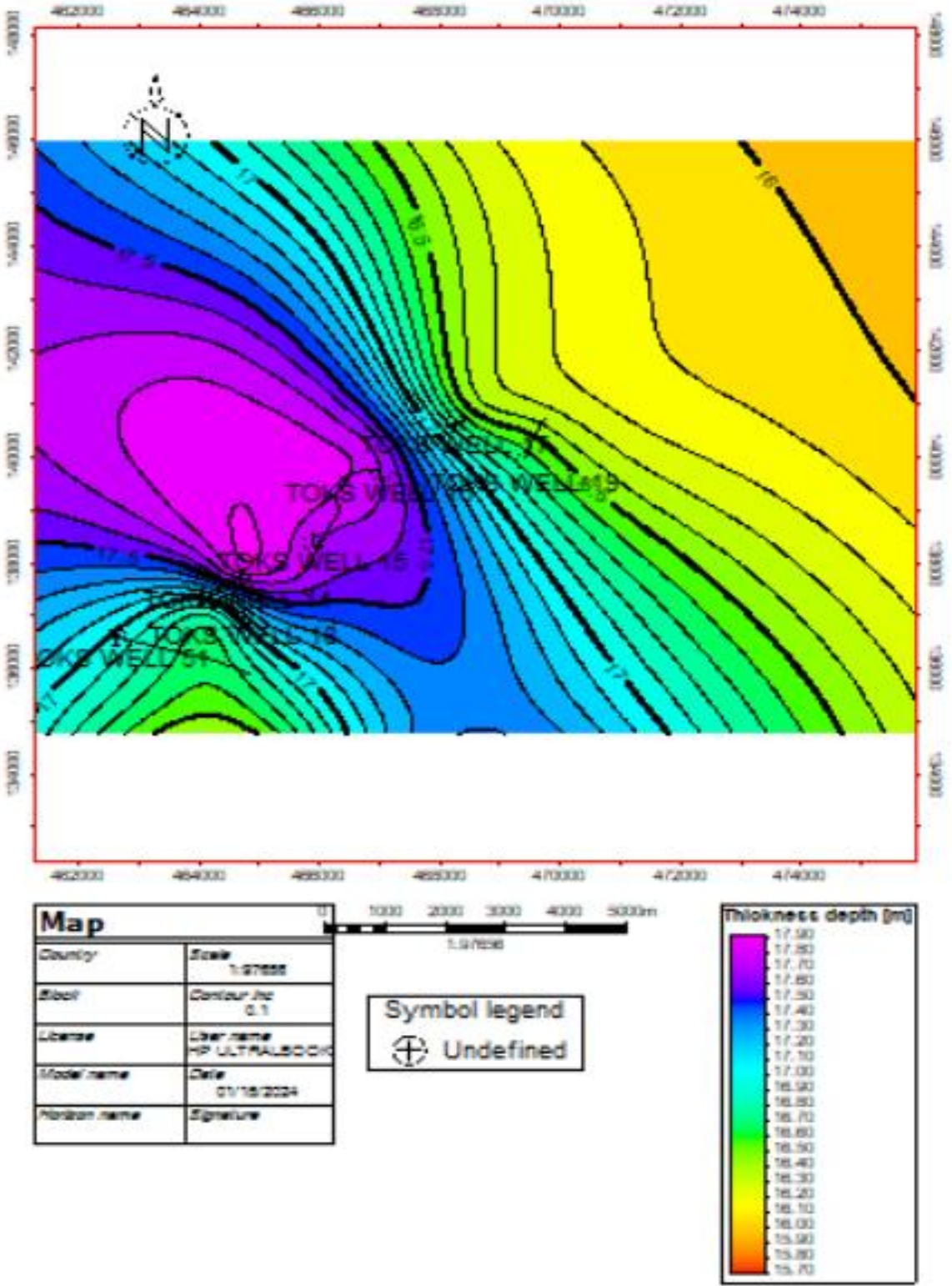


Fig. 4.7: Isochore map showing the thickness of TOKS 3000 Reservoir zone

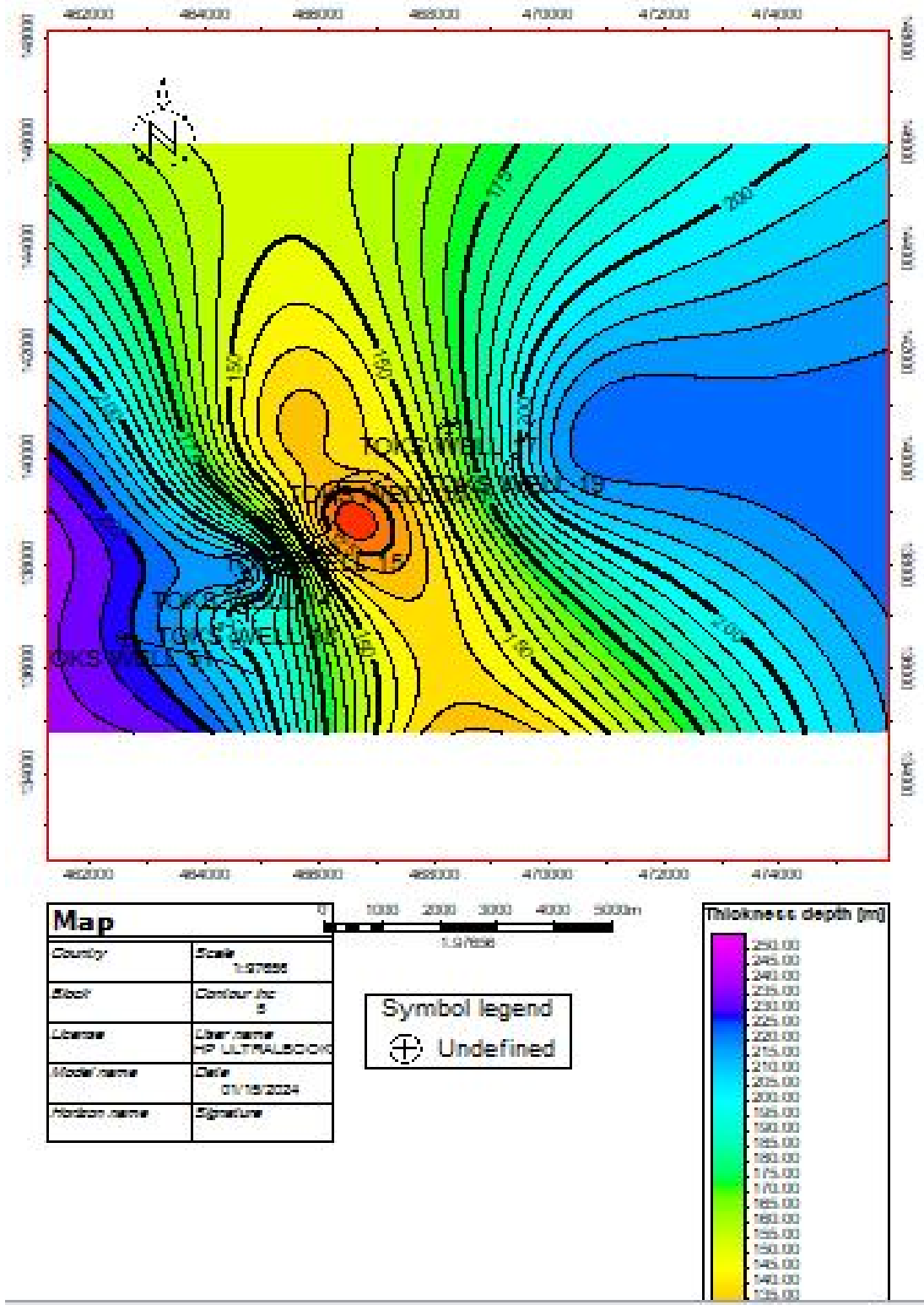


Fig. 4.8: Isochore map showing the thickness of TOKS 4000 reservoir zone

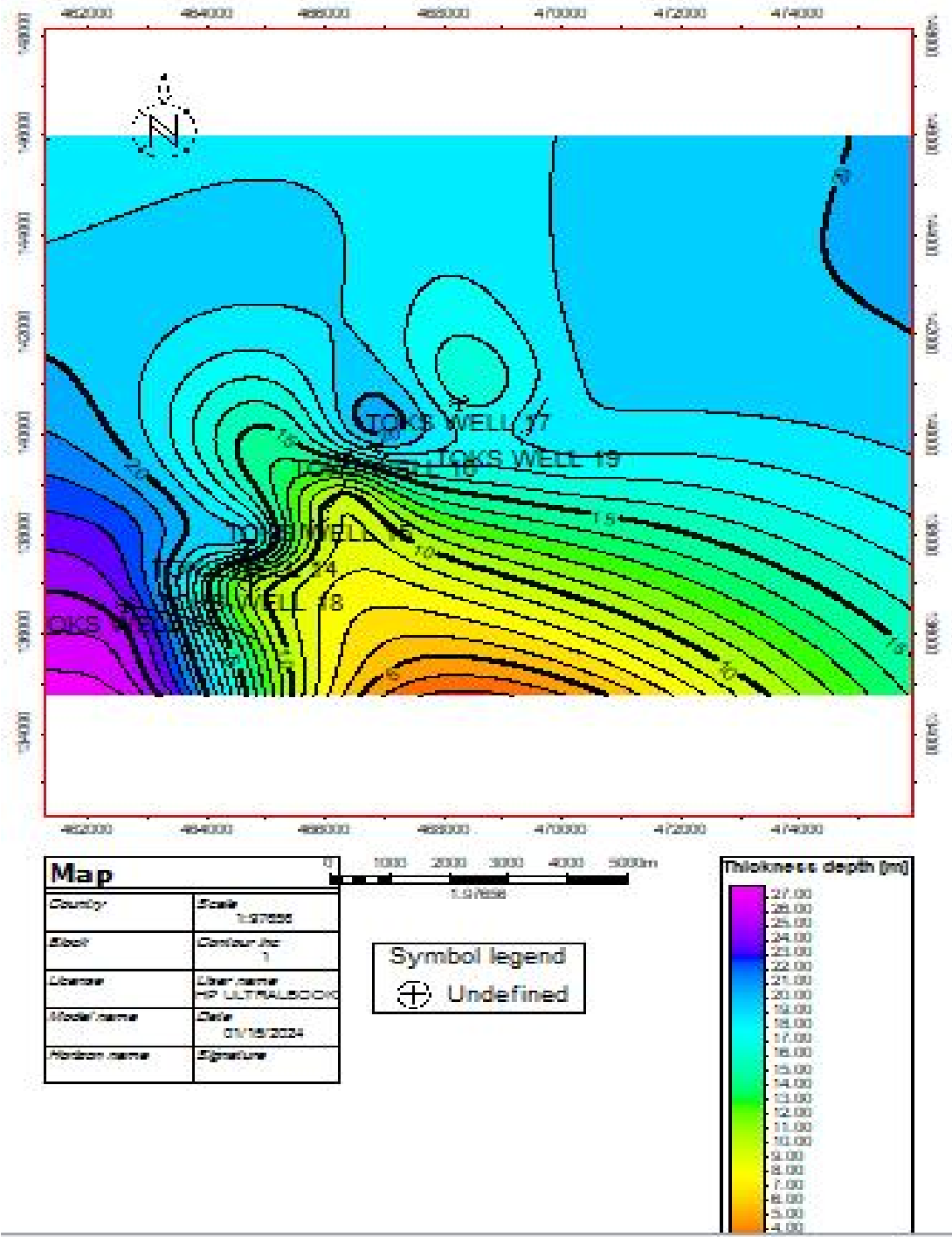


Fig. 4.9: Isochore map showing the thickness of TOKS 5000 reservoir zone

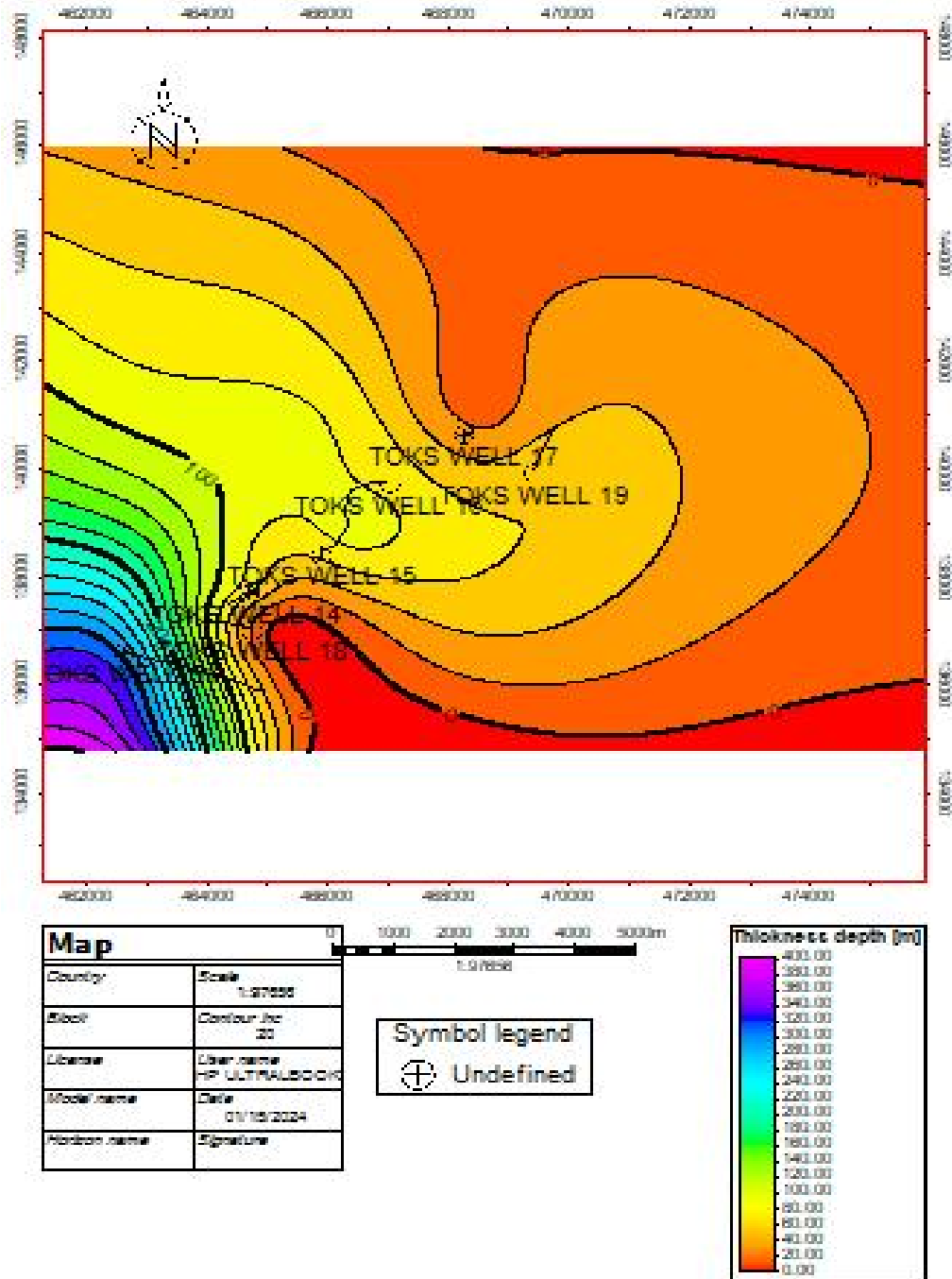


Fig. 4.10: Isochore map showing the thickness of TOKS 6000 reservoir zone

4.3 SEISMIC INTERPRETATION

The 3D seismic data with the wells displayed on the section and Horizons/Seeds seismic data for TOKS1000 and TOKS3000 are presented in figure 4.11 and figure 4.12 respectively.

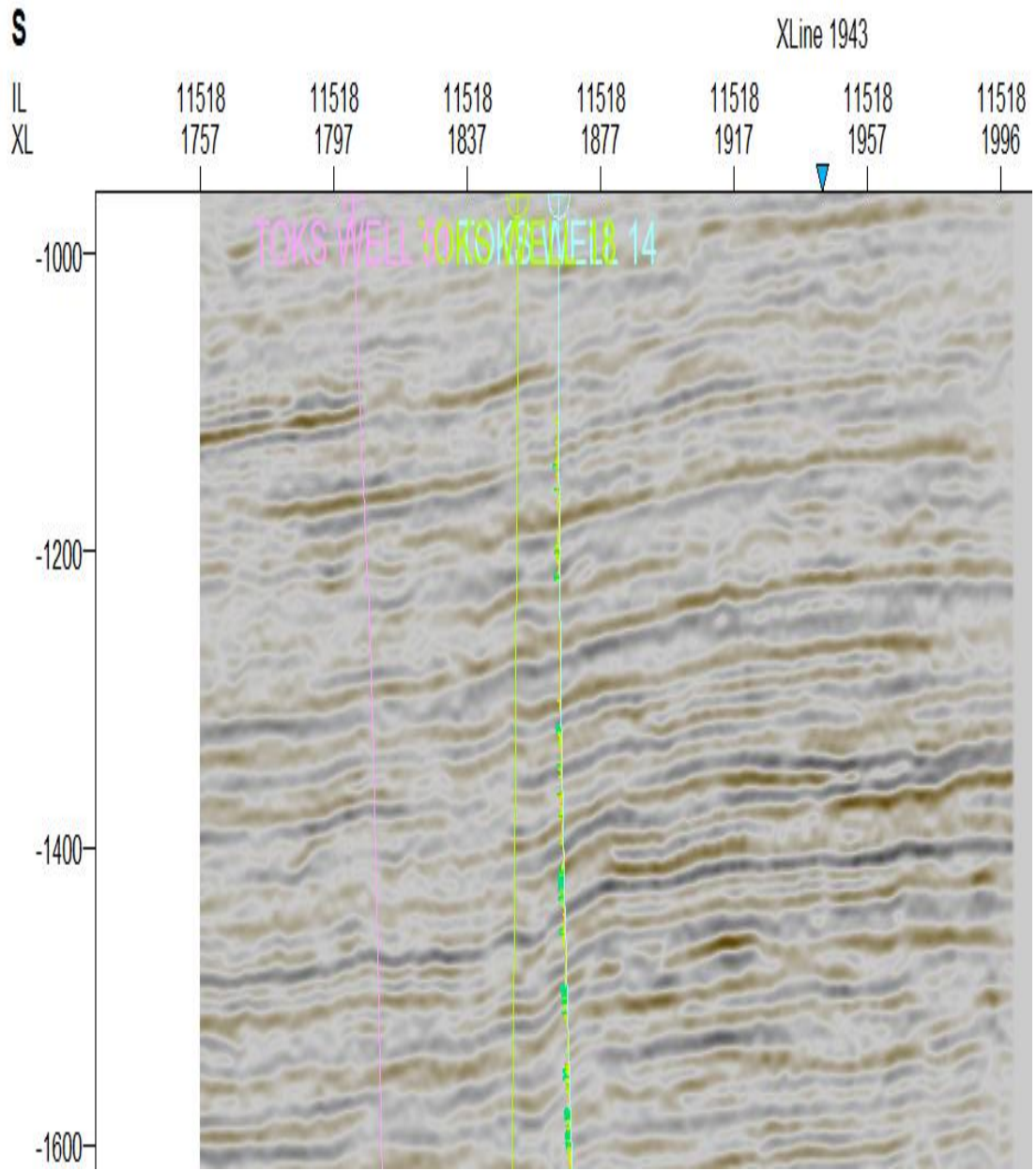


Fig. 4.11: 3D seismic data with the wells displayed on the section

Geological modelling or static modelling involves populating the reservoir architecture (structure and stratigraphy) with rock properties. For the necessity of dynamic simulation process and to arrive at a final well and production behavior, it was necessary to build a static model that represented as closely as possible the subsurface reality of the sandstone that have been encountered in TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 for TOKS 1000 and TOKS 3000 reservoirs.

The 3D seismic structural interpretation property models such as the porosity, net – to – gross, water saturation and shale volume models from log analyses were utilized to build the static model for TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 for TOKS 1000 and TOKS 3000 in TOKS field, Niger Delta Basin, Nigeria.

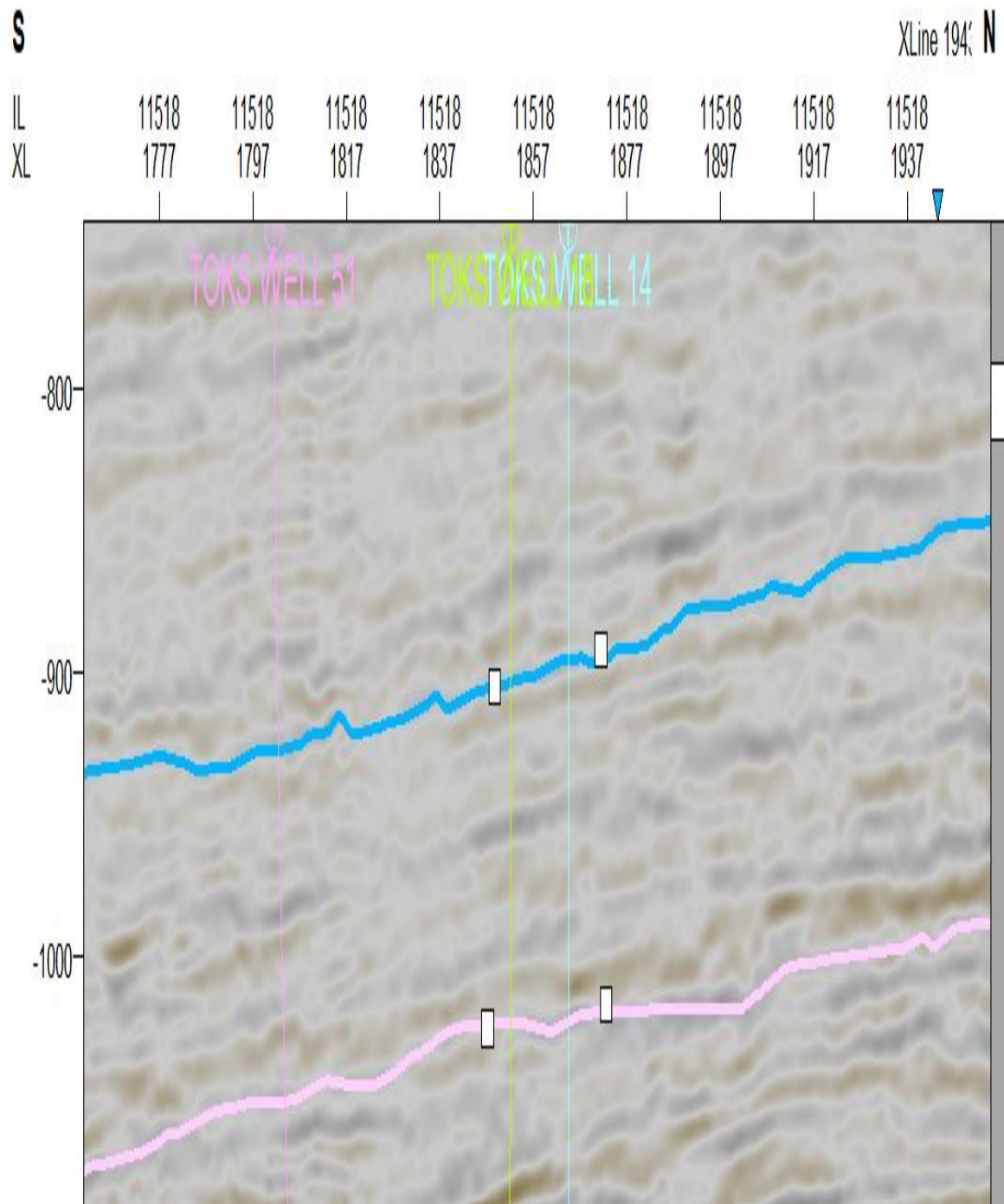


Fig. 4.12: Horizons/Seeds Interpretation (TOKS1000 and TOKS3000)

Horizons/Seeds Interpretation (TOKS 1000 and TOKS 3000)

Two horizons that correspond to top of reservoirs TOKS1000 and TOKS3000 were interpreted

The horizon interpretation was done on a 10X10 step

The reservoir tops all correspond to trough events.

The mapping of the horizon is based on synthetic seismogram generated (Figure 4.12). The key seismic reflections that corresponds to the top of main reservoir sands were identified on seismic data for mapping. Two (2) horizons corresponding to the top and base of the reservoir were mapped at TOKS well 14 and TOKS well 51 (reservoir tops and base) TOKS 1000 and TOKS 3000 (Figure 4.13). The horizons were picked on inlines and crosslines in TOKS field, Niger Delta Basin, Nigeria.

Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, The time structural maps and depth structural maps are the subsurface maps that helps us to identify areas with our reservoirs. The time maps were generated from the interpreted horizons using convergent interpolation algorithm

From the time structural maps in Figure 4.16, Figure 4.17, Figure 4.18, Figure 4.19, Figure 4.20, Figure 4.21, Figure 4.22 for TOKS 1000 Horizon, TOKS 2000 Horizon, TOKS 3000 Horizon, TOKS 4000 Horizon, TOKS 5000 Horizon, TOKS 6000 Horizon, TOKS 7000 Horizon and TOKS 8000 Horizon in the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Nigeria the depth maps for H1000, H2000, H3000, H4000, H5000, H6000, H7000 and H8000 were generated using polynomial function. A polynomial function

was used for the TDR. The polynomial equation was derived from a plot of the time-depth pairs obtained from the combined time depth relationship (TDRs) from the well data. $y = 1.52112 + 1.87613 * \text{pow}(x,1) - 0.000302648 * \text{pow}(x,2)$

Time-Depth Relationship of Wells Used for Depth Conversion

The polynomial function was used to generate a time-depth relationship that was used to produce depth maps that better mimic the time structure maps for the horizons and structures picked across the study area (Figure 4.15 and Figure 4.16). It shows that the most dominant trap was the generated rollover anticlines trending Northwest, Northeast – Southwest. The presence of roll – over structures indicates possible hydrocarbon accumulation in the vicinity of such roll – over structures in the mapped at TOKS well 14 and TOKS well 51 (reservoir tops and base) TOKS 1000 and TOKS 3000. The horizons were picked on inlines and crosslines in TOKS field, Niger Delta Basin, Nigeria. This is in consistent with works of Dawarzan *et al.*, (2023).

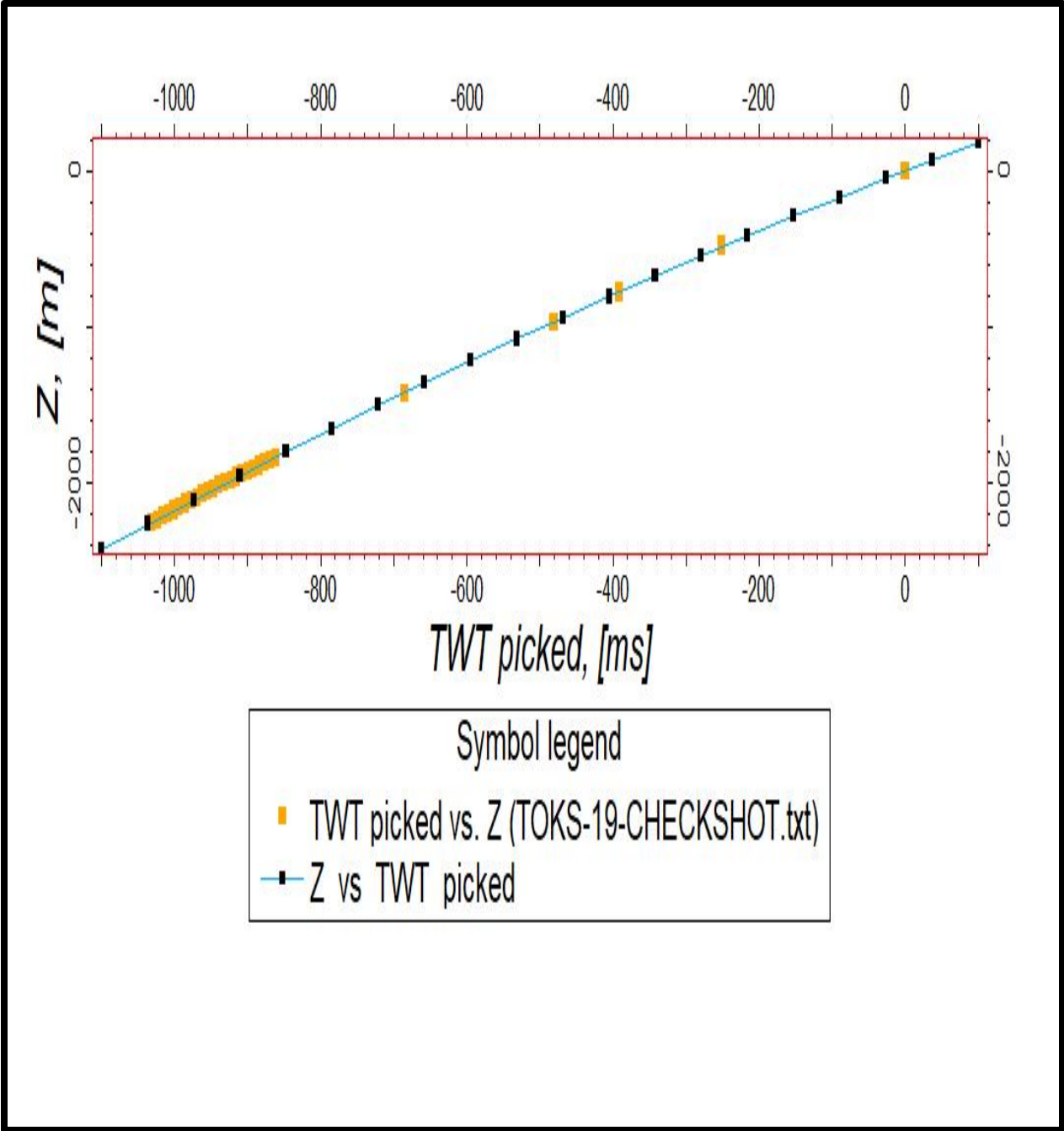


Figure 4.13: Time-Depth Relationship of Wells Used for Depth Conversion

Picked Seismic Horizon

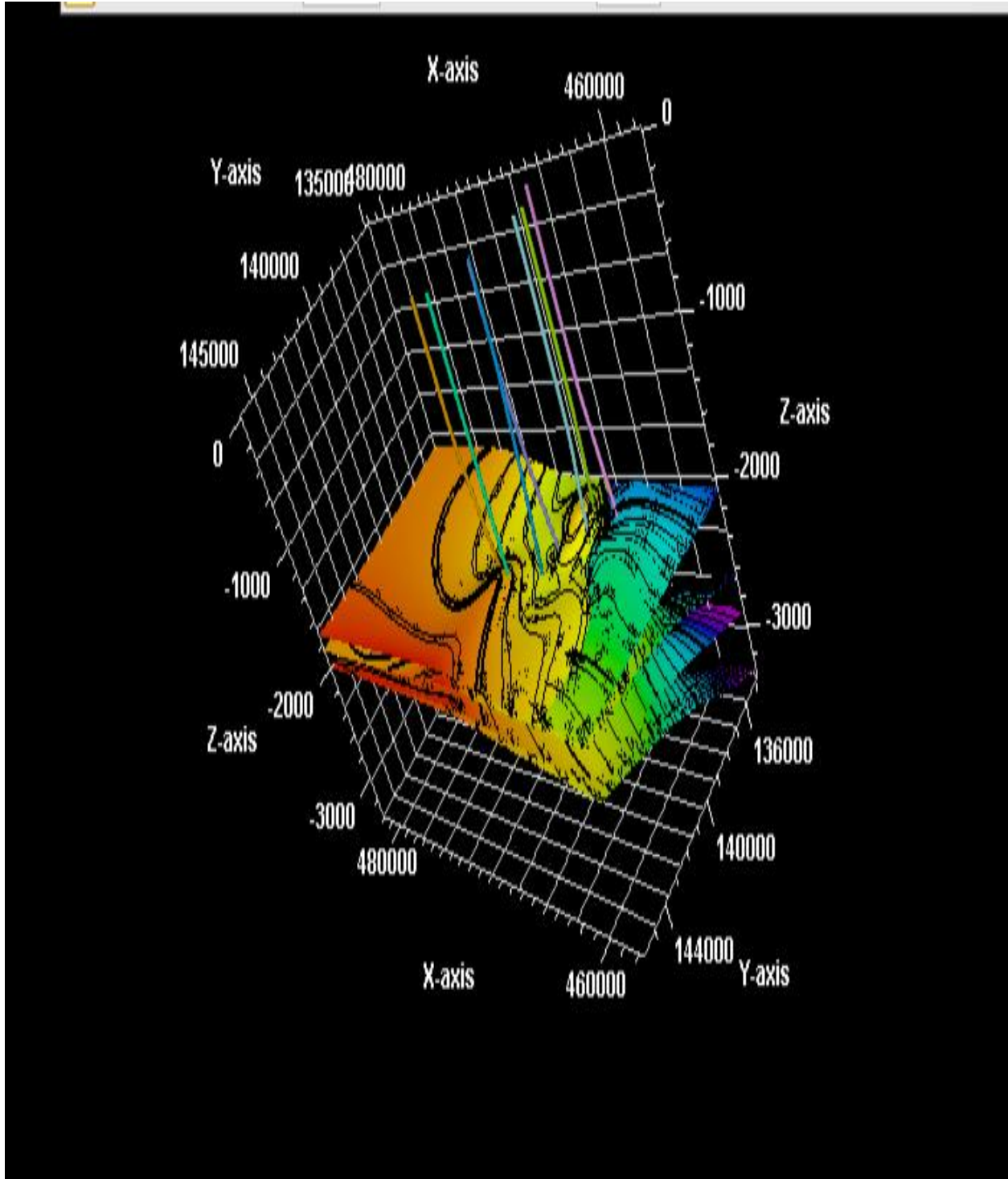
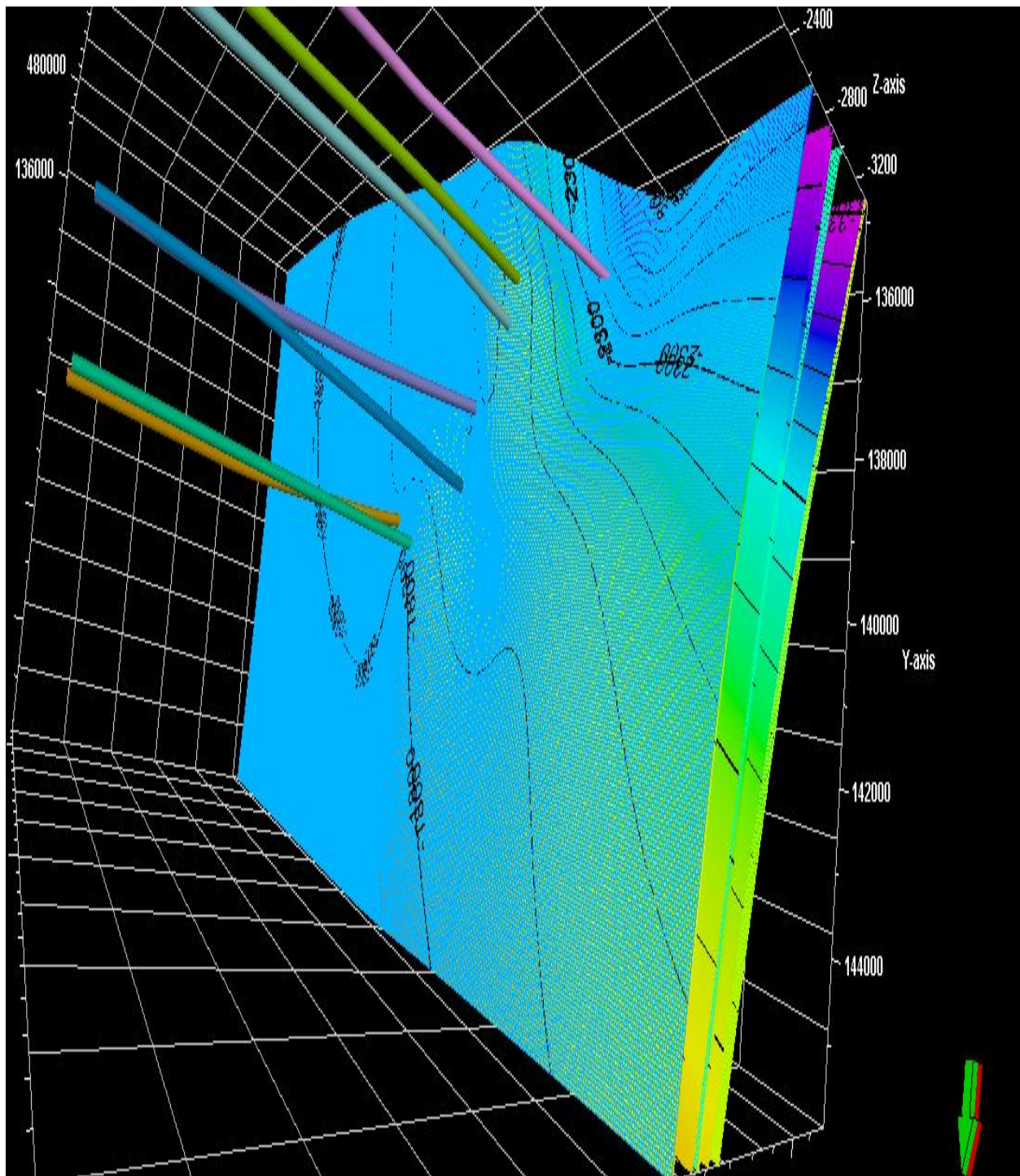


Figure 4.14: Picked Seismic Horizon cross section for TOKS wells reservoir



**Figure 4.15: Picked Seismic Horizon Cross Section Direction for TOKS wells reservoir
Converted to Surface (Time)**

In reservoir characterization, picking seismic horizons is the identification of reflectors on seismic data and is the first step during the conversion of seismic horizon to time maps. The horizon maps are converted to time (surface) maps which are isochron maps representing the two – way travel time of seismic waves to that horizon. The time – depth maps (isodepth maps) using seismic time – depth conversion processes, allows for better understanding of reservoir geometry and other properties.

The picked seismic horizon cross section for reservoirs in the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria are represented by figure 4.14.

The picked seismic horizon cross section direction for TOKS wells reservoir converted to surface (time) map for reservoirs in the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria are represented by figure 4.15.

Time Structural Maps

The time maps were generated from the interpreted horizons using convergent interpolation algorithm. The Subsurface Map helps us to identify areas with our reservoir.

The time structural map in the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria for TOKS 1000 Horizon is represented by figure 4.16.

The time structural map in the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria for TOKS 2000 Horizon is represented by figure 4.17.

The time structural map in the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria for TOKS 3000 Horizon is represented by figure 4.18.

The time structural map in the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria for TOKS 4000 Horizon is represented by figure 4.19.

The time structural map in the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria for TOKS 5000 Horizon is represented by figure 4.20. The time structural map in the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria for TOKS 6000 Horizon is represented by figure 4.21.

The time structural map in the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria for TOKS 7000 Horizon is represented by figure 4.22.

The time structural map in the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria for TOKS 8000 Horizon is represented by figure 4.23.

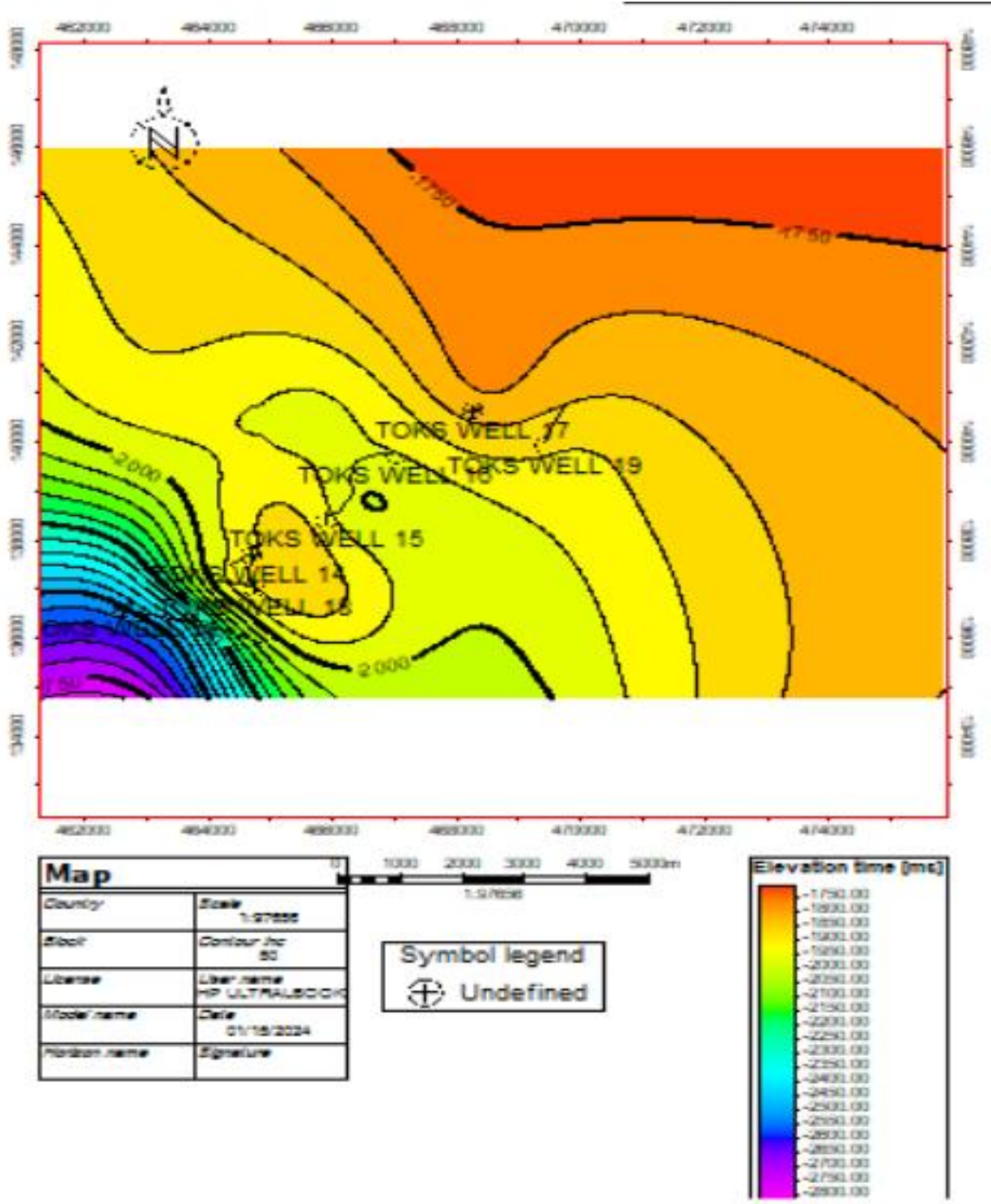


Figure 4.16: Time Structural Maps – TOKS 1000 Horizon

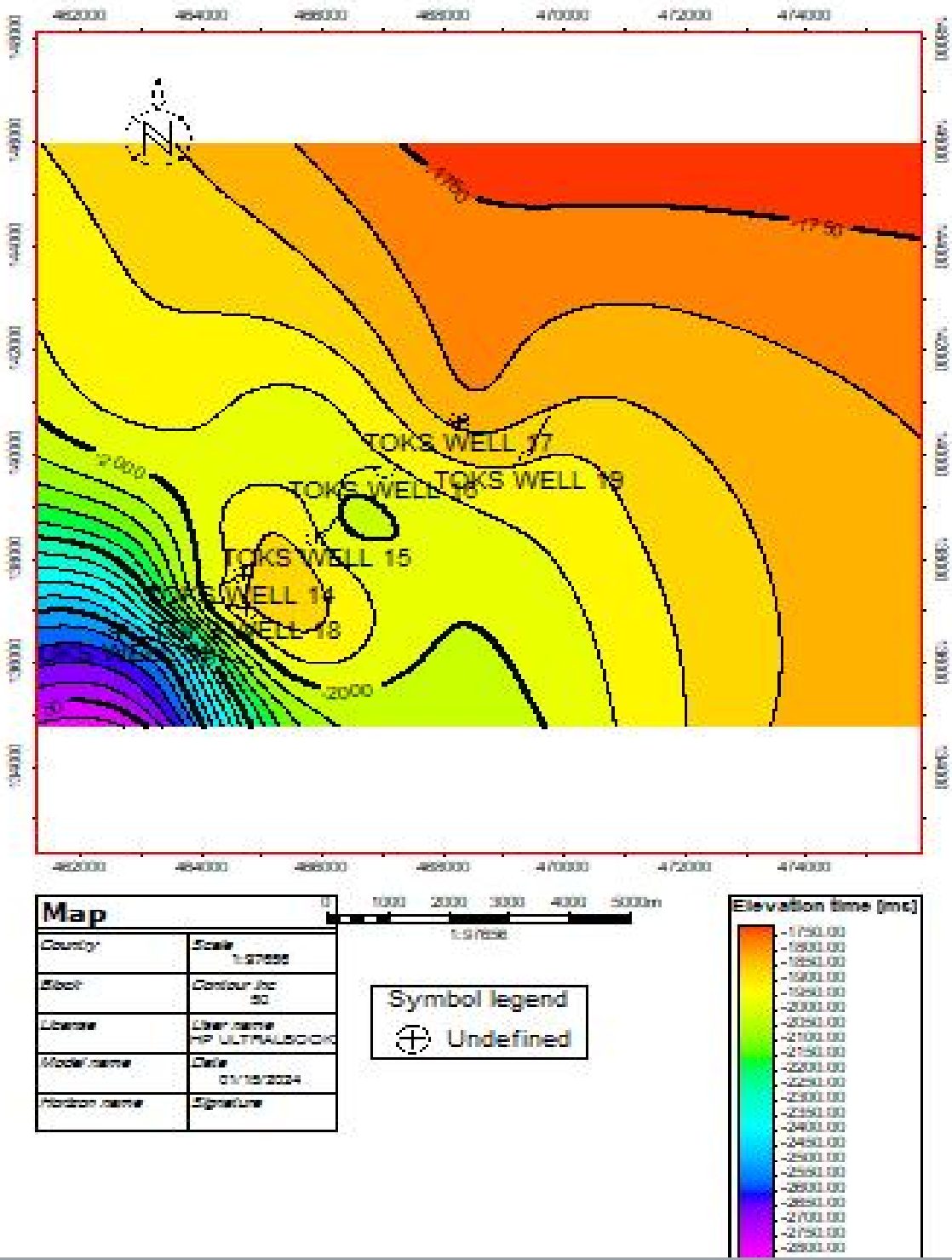


Figure 4.17: Time Structural Maps – TOKS 2000 Horizon

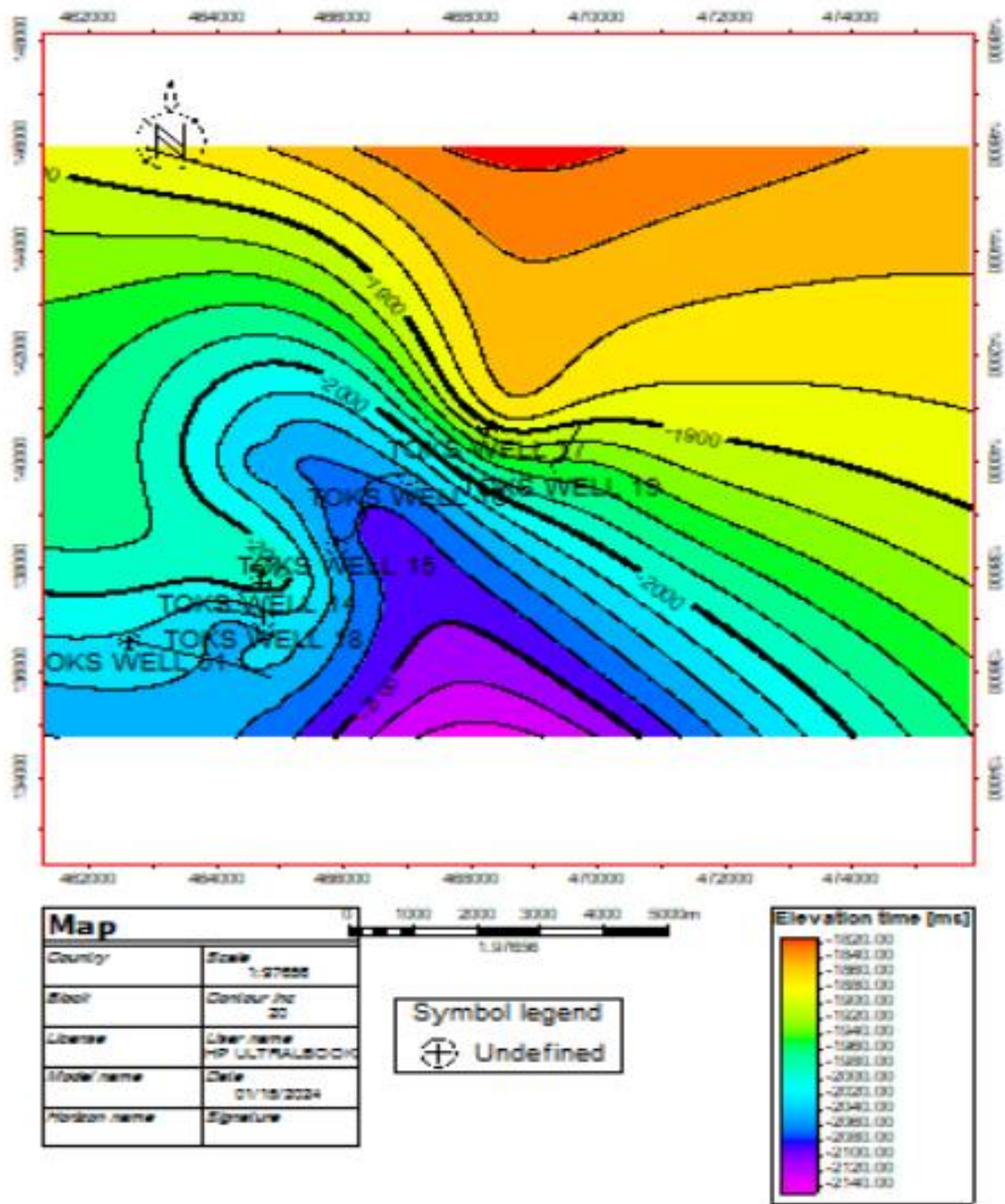


Figure 4.18: Time Structural Maps – TOKS 3000 Horizon

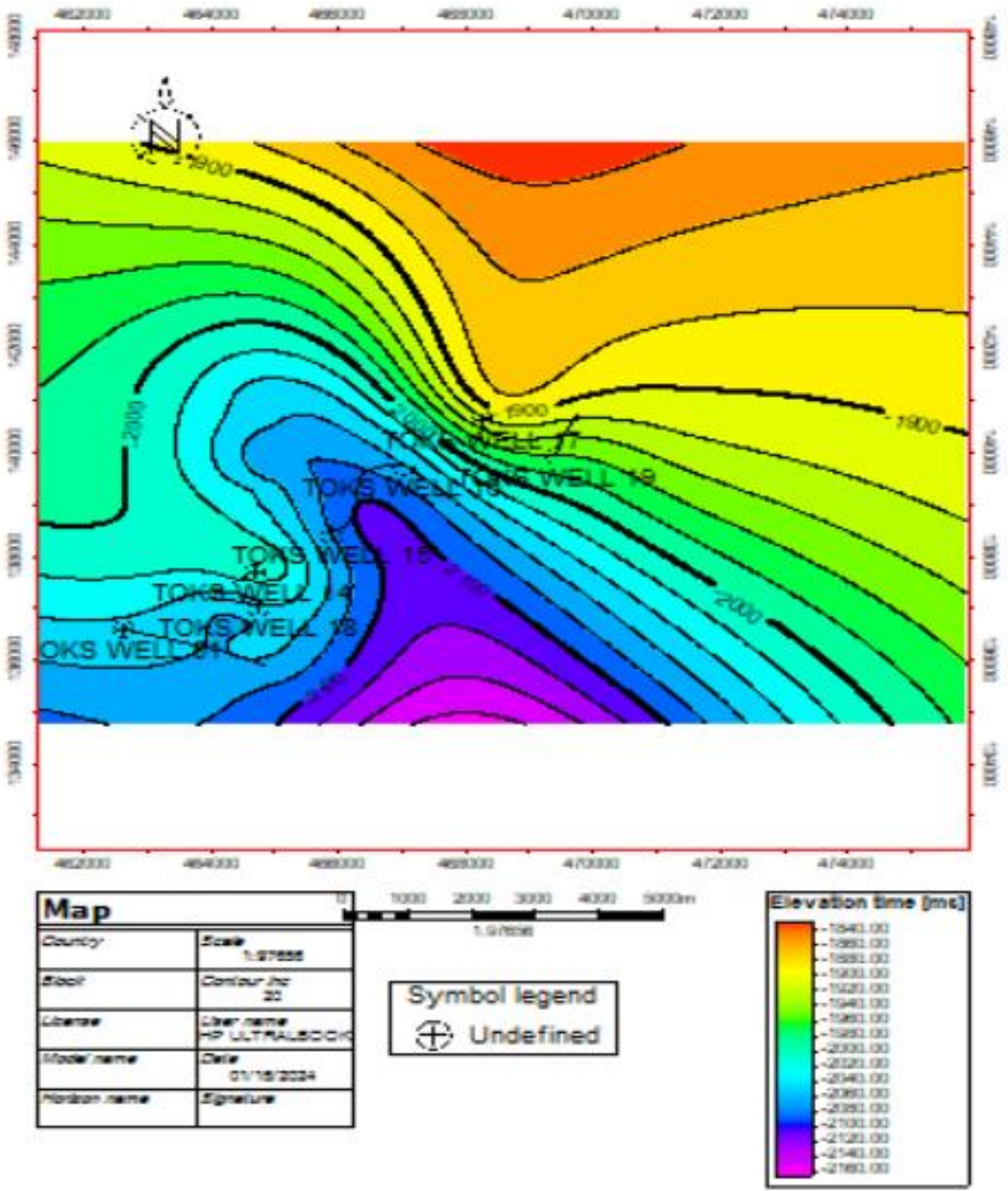


Figure 4.19: Time Structural Map– TOKS 4000 Horizon

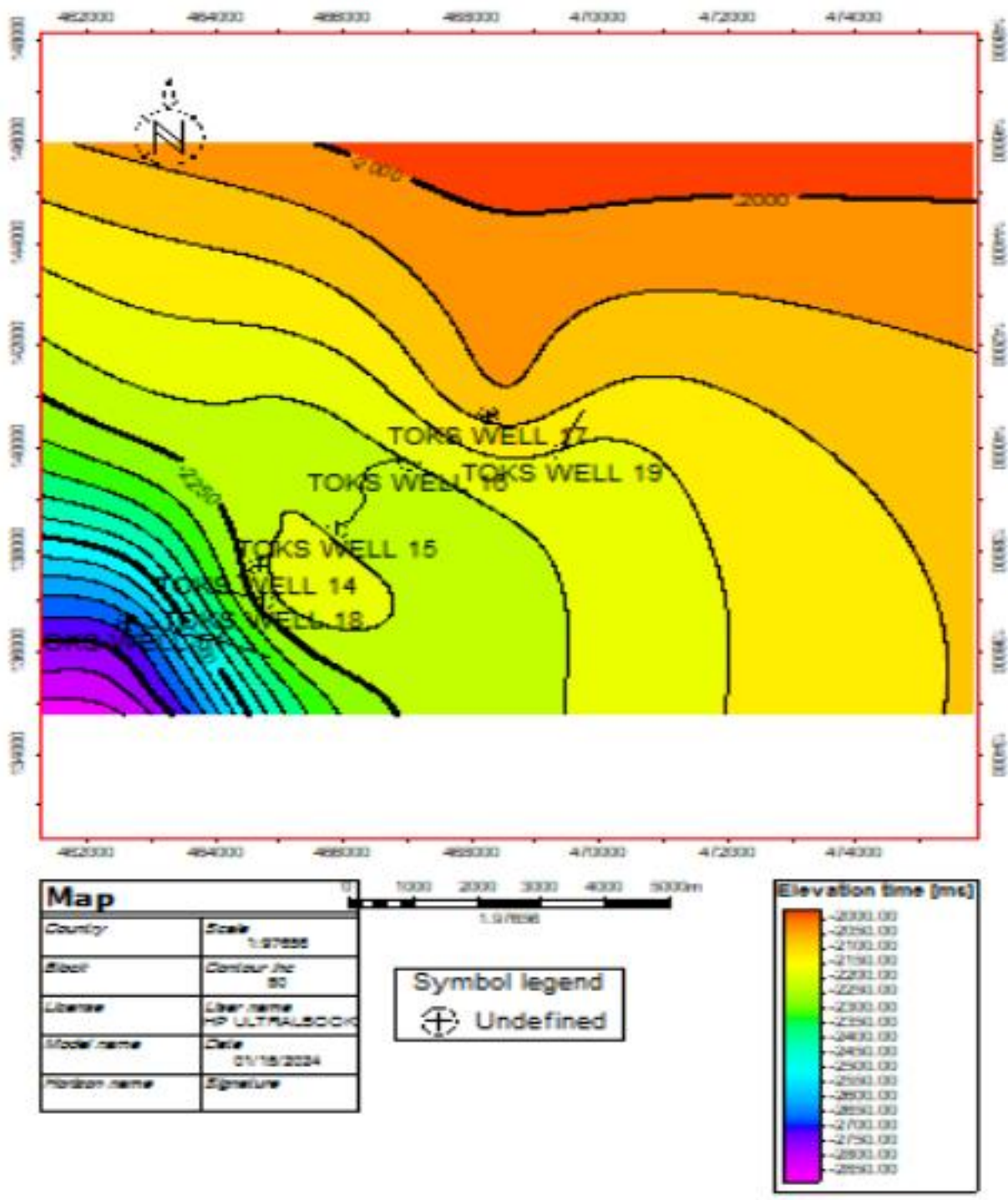


Figure 4.20: Time Structural Map – TOKS 5000 Horizon

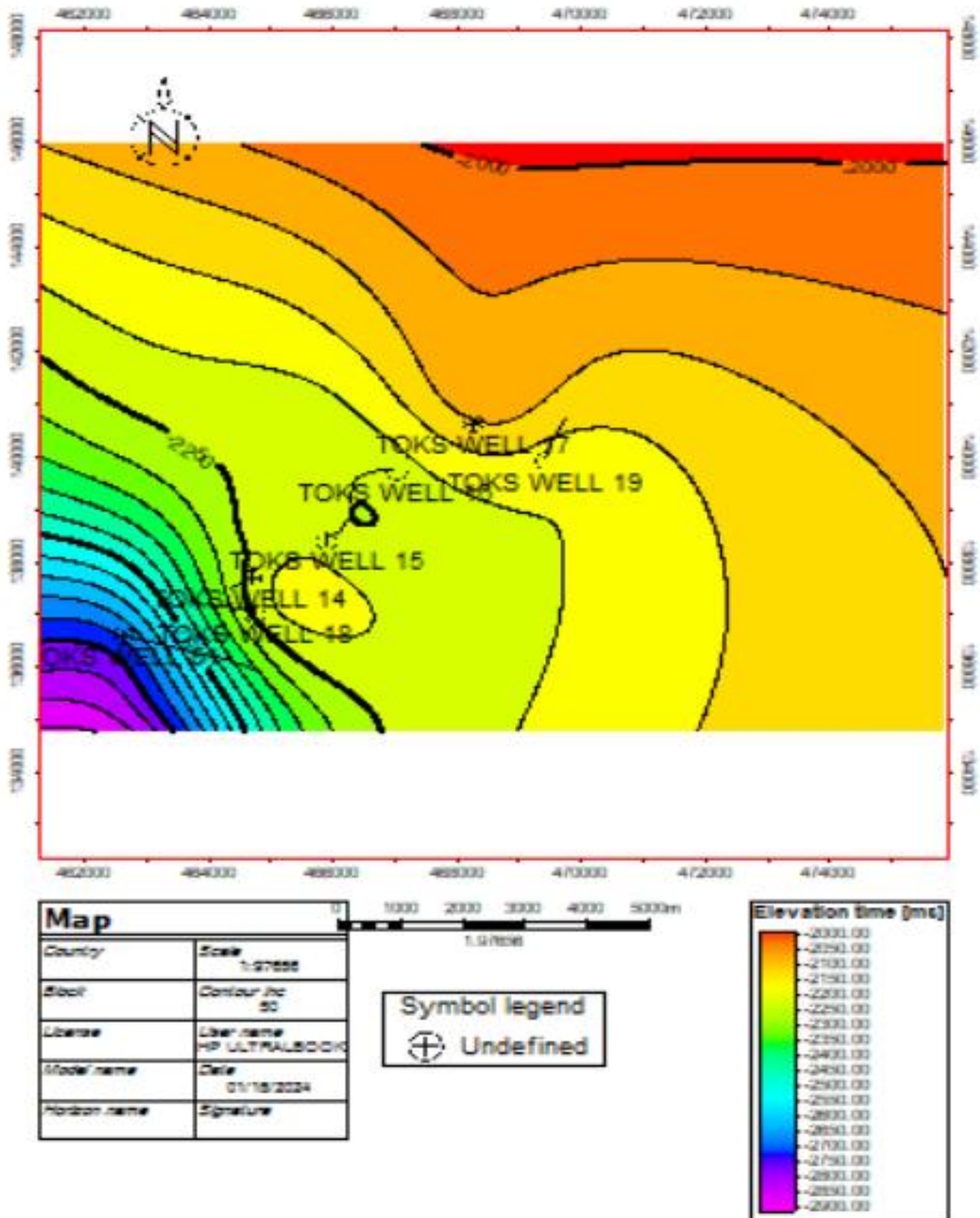


Figure 4.21: Time Structural Maps – TOKS 6000 Horizon

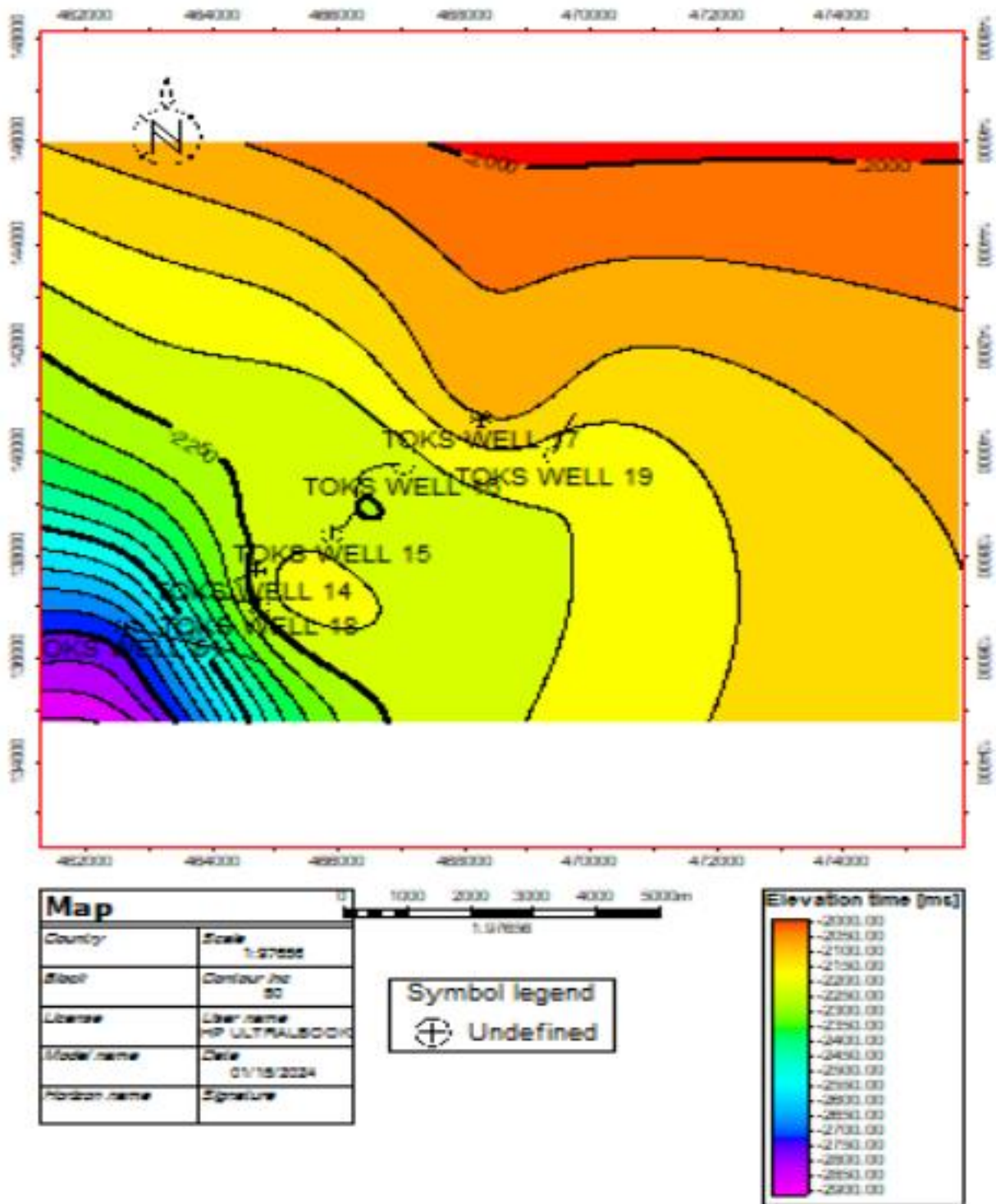


Figure 4.22: Time Structural Maps – TOKS 7000 Horizon

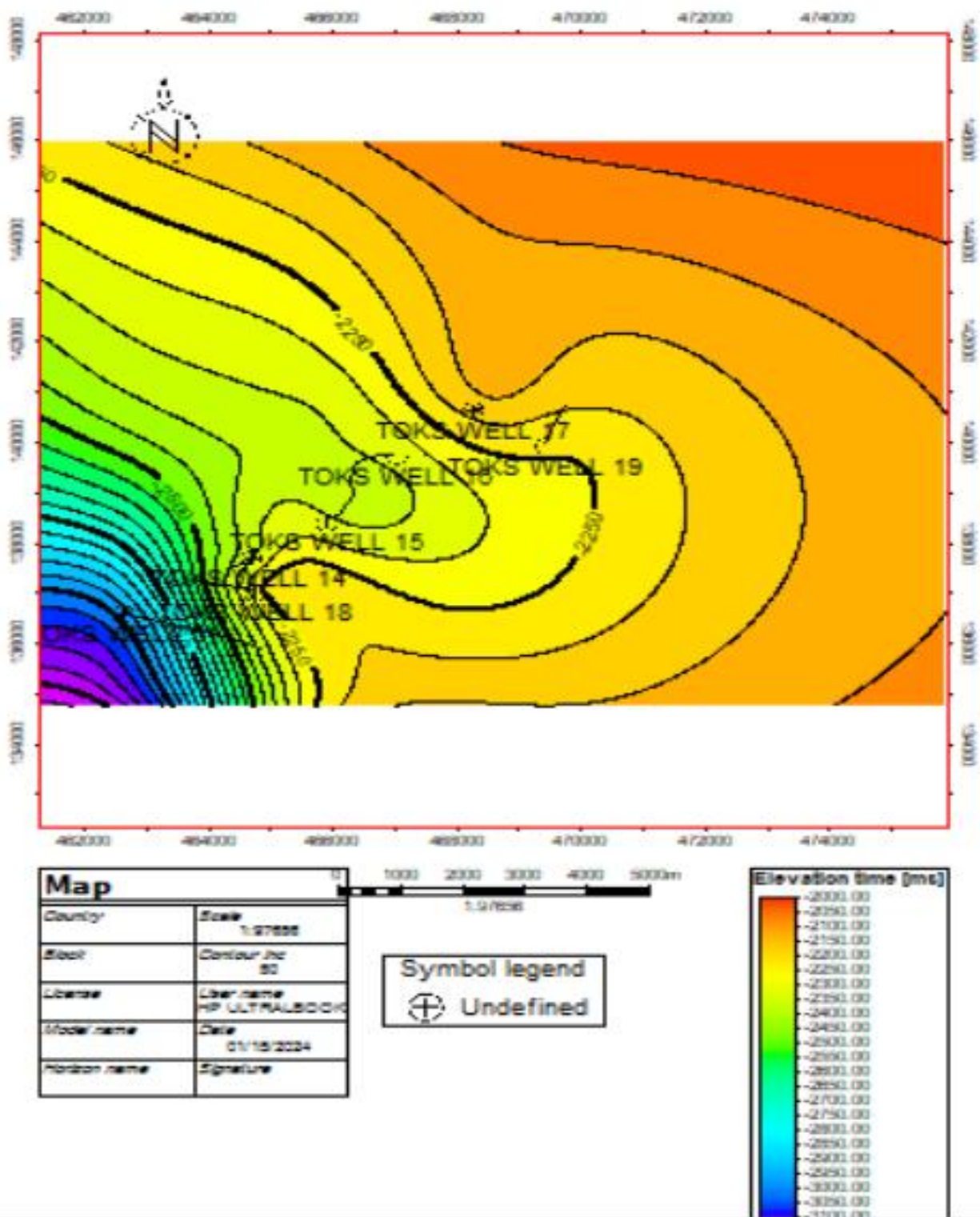


Figure 4.23: Time Structural Maps – TOKS 8000 Horizon

Post-Stack Seismic Inversion of TOKS Field

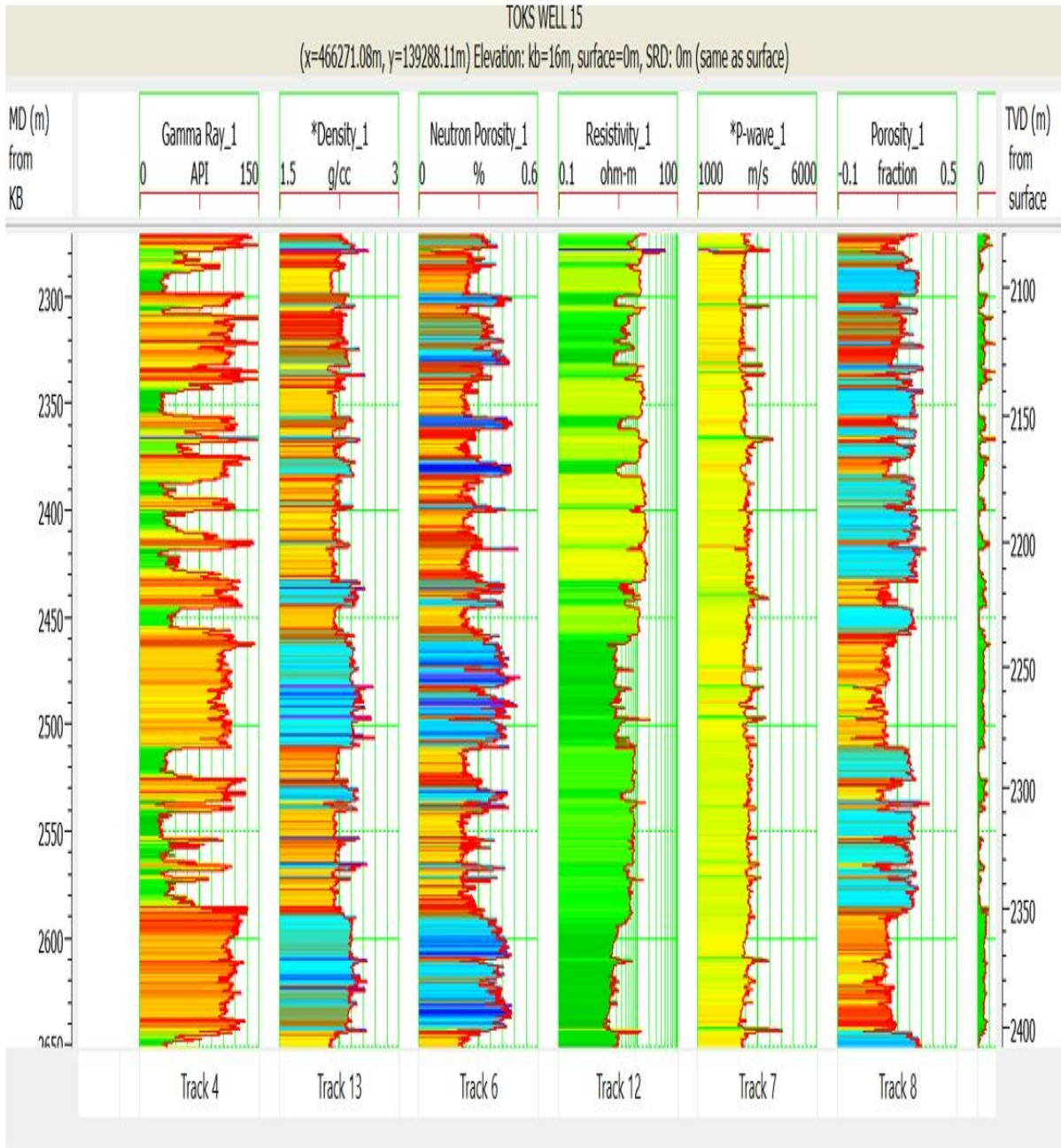


Figure 4.24: Petrophysical well logs analysis of TOKS Field using Post-Stack Seismic Inversion

The petrophysical well log analysis of the studied wells TOKS Well 15 in TOKS Field, Niger Delta Basin shows five logs (Gamma ray, Density, Sonic, P-Wave Sonic and Neutron porosity) were utilized for the Post – Stack Seismic Inversion. The gamma ray log was used to distinguish between shale and sand units, serving as a lithological indicator for defining clean reservoir intervals and identifying potential hydrocarbon-bearing zones. The density log provided bulk density measurements essential for acoustic impedance computation when combined with the compressional sonic log. The P-wave sonic log (DT) measured formation transit time, which was converted to velocity and integrated with the density log to derive the acoustic impedance (AI) curve, a primary input for post-stack inversion.

The neutron porosity log was used alongside the density log to estimate effective porosity and to identify gas effects or lithological variations through crossplots. The resistivity log aided in fluid discrimination, distinguishing hydrocarbon-bearing zones from water-saturated formations. All logs were quality-controlled through depth matching, despiking, and correction of washout zones to ensure consistency and accuracy.

Following conditioning, the logs were imported into Hampson Russell's Well module in LAS format. The acoustic impedance log was correlated with seismic reflectivity data for wavelet extraction and calibration. This petrophysical analysis established a robust link between seismic amplitudes and reservoir properties, allowing for accurate inversion results. The integration of these well logs significantly enhanced the interpretation of lithological and fluid variations across the TOKS Field, thereby improving confidence in reservoir prediction and guiding optimal well placement in the undrilled location.

3D Seismic Data Importation

For the post-stack seismic inversion of TOKS Field using Hampson Russell software, the 3D post-stack seismic data were imported to provide the reflectivity information necessary for generating acoustic impedance models. The seismic data, in SEG-Y format, were first verified for correct trace headers, coordinate system, and time sampling interval to ensure compatibility with the inversion workflow. The imported seismic cube covered the target reservoir interval and was checked for consistency, amplitude balance, and signal-to-noise ratio.

Selected SEG-Y File: TOKS 3D Seismic New.segy

Volume Name: TOKS 3D Seismic New

Amplitude Type: Seismic Amplitude Unit:

Domain : Time ms

This is a Post-stack volume. Bin Type: Offset

Do you have Inline and Xline numbers in the trace headers? Yes No

Do you have X & Y coordinates in the trace headers? Yes No

Primary key for assigning traces to bin location: Inline and Xline Header Editor...

Renumber the CDPs sequentially (suggest Yes for 3D, No for 2D)? Yes No

The program needs to create some files for storing information about the volume. By default, the information files are created where your input Segy file is located, but you can specify a directory path below.

Create information files in this directory: C:\Users\USER\Desktop\Tochi Inversion\ ...

Figure 4.25: 3D seismic data importation process of TOKS Field

After importation, the seismic volume was visually inspected within Hampson Russell's Seismic Viewer to confirm data integrity and structural continuity. Key horizons defining the top and base of the reservoir were also imported from Petrel and used to constrain the inversion zone. The seismic data were then tied to the well control through synthetic seismograms to ensure accurate time alignment and amplitude calibration. This integration between the seismic and well data provided the foundation for reliable wavelet extraction, low-frequency model building, and acoustic impedance inversion. The quality and calibration of the imported 3D seismic data were critical to achieving a robust inversion output for predicting reservoir properties and optimizing well placement in the undrilled location.

Seismic Horizons Importation

The post-stack seismic inversion of TOKS Field using Hampson Russell software imported three interpreted horizons, these key interpreted horizons includes TOKS_200H, TOKS_500H, and TOKS_700H and were imported to define the stratigraphic boundaries and constrain the inversion process. These horizons, previously interpreted in Petrel from the 3D seismic volume, represent significant geological markers that delineate reservoir tops and bases within the field. Prior to importation, the horizons were exported in XYZ (ASCII) format containing inline, crossline, and time (TWT) values, ensuring compatibility with the inversion workflow.

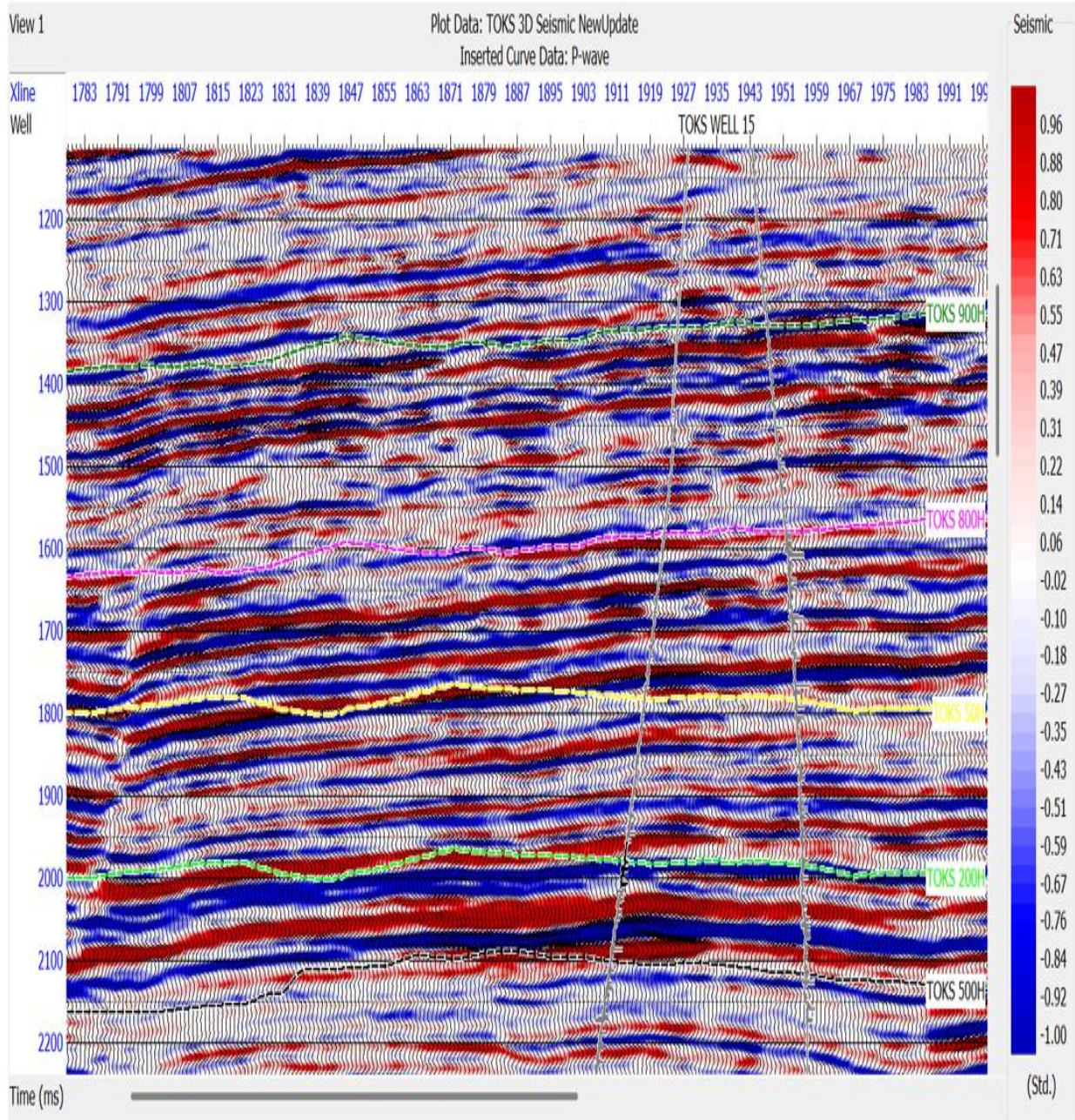


Figure 4.26: Interpreted horizons on the seismic section.

In Hampson Russell, the horizons were loaded into the Seismic module and visually verified to confirm alignment with the imported seismic cube. The horizons served as vertical and lateral constraints during wavelet extraction, low-frequency model building, and inversion window definition, ensuring that the inversion focused precisely on the reservoir interval of interest. By incorporating these mapped surfaces, the inversion results were geologically consistent with the field's structural framework. The integration of TOKS_200H, TOKS_500H, and TOKS_700H horizons therefore played a crucial role in accurately capturing reservoir geometry, improving inversion reliability, and enhancing the prediction of lithological and fluid variations critical for well placement in the undrilled location.

Sonic Calibration

The post-stack seismic inversion of TOKS Field using Hampson Russell software, sonic calibration was performed on TOKS Well 14, TOKS Well 15 and TOKS Well 16 to ensure accurate time-to-depth correlation between well logs and seismic data. This process was essential for generating reliable synthetic seismograms, wavelet extraction, and subsequent inversion calibration.

The compressional sonic (DT) and density (RHOB) logs from each well were first quality-controlled by removing spikes, filtering noise, and correcting washout intervals. Checkshot data were then used to establish a time–depth relationship, enabling conversion of the sonic log from depth to two-way travel time. In Hampson Russell's Well module, the depth-based logs were calibrated to seismic time using this checkshot-derived velocity model to eliminate misties between synthetic and real seismic traces.

Synthetic seismograms were generated for each well and compared against the seismic reflection data to validate the calibration. Where necessary, minor velocity adjustments were applied to achieve optimal tie, with correlation coefficients exceeding acceptable thresholds for inversion input.

This calibration ensured that the well-derived acoustic impedance and reflectivity matched the seismic domain, providing a consistent foundation for wavelet extraction and post-stack inversion modeling. Accurate sonic calibration across the three wells improved the reliability of the inversion results by reducing depth–time uncertainties and enhancing the alignment between seismic amplitudes and petrophysical properties. Consequently, it strengthened the interpretative confidence in mapping reservoir continuity and quality in undrilled areas, thereby supporting optimal well placement and improved field development planning in TOKS Field.

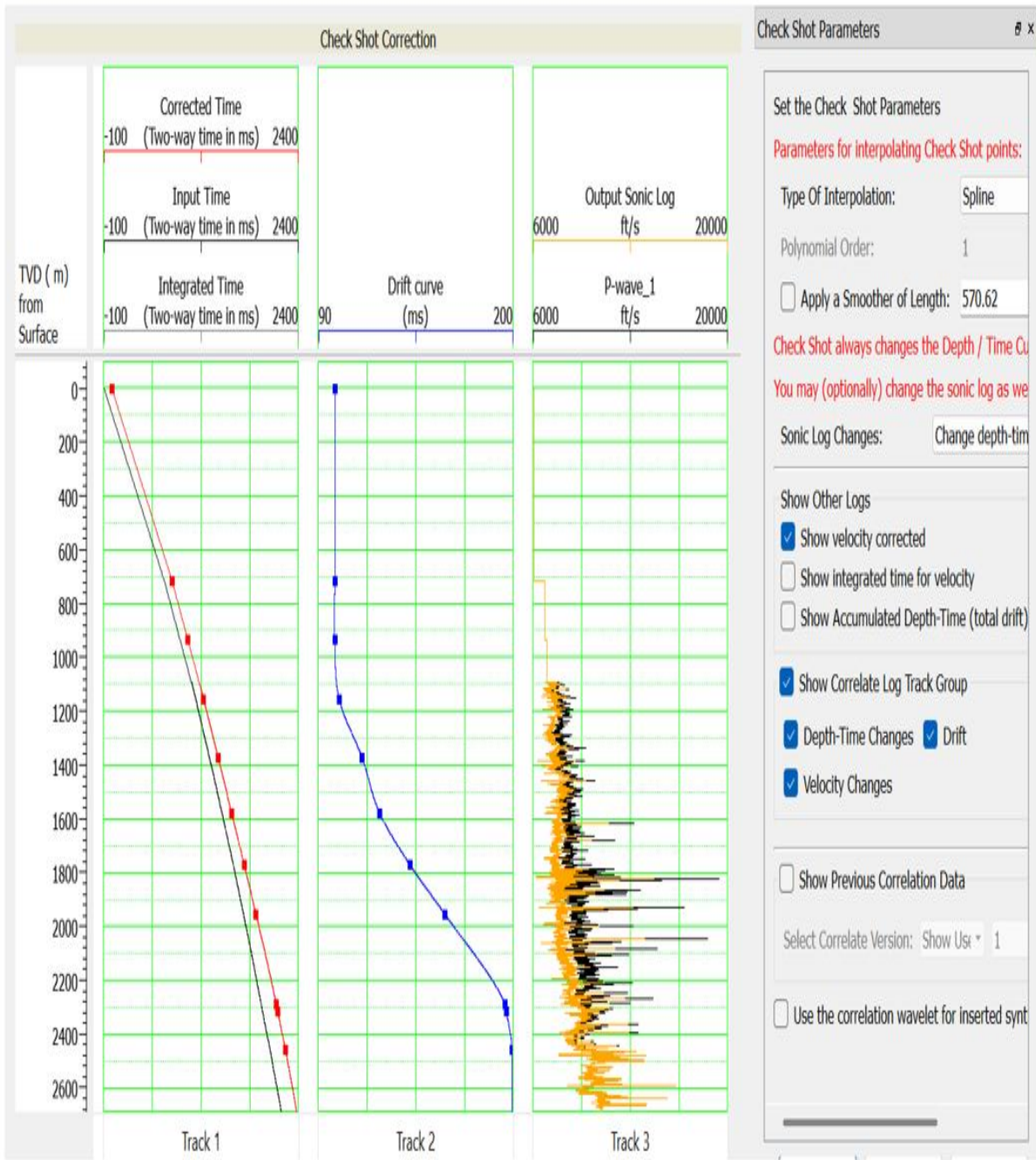


Figure 4.27: Sonic calibration process.

The blue colour shown in Fig.6 is the drift curve and implies the difference between the input P-wave and the output P-wave (sonic log). If you have these differences between the input and the output, that is, the input time and the integrated time. The integrated time calculated from the sonic log. And then, you compare the integrated time with the input time of the check-shot. It is the difference that is display as the drift curve. When we apply this drift curve, we see the differences in the sonic logs (3rd track). That's is, the effect of the differences (drift curve) is what is seen when we display the input and the output sonic (p-wave) log in the third track. If you find a big difference b/w the output and the input sonic log, this may tell you need to go back and check the inputted sonic log again.

Deterministic Wavelet Extraction

The post-stack seismic inversion of TOKS Field using Hampson Russell software, a deterministic wavelet extraction was carried out to generate a synthetic seismic section for accurate well-to-seismic tie. The deterministic approach was chosen because it allows the extraction of a wavelet that closely represents the true seismic source signature within the study area, providing a reliable link between well log reflectivity and seismic amplitudes.

The process began by importing the seismic data, checkshot-survey-corrected sonic and density logs from TOKS Wells 14, 15, and 16 into Hampson Russell's Wavelet module. The logs were used to compute reflection coefficients, which were convolved with an initial wavelet estimate to produce synthetic seismic traces. These synthetic traces were then compared with the corresponding field seismic traces to assess the degree of correlation. Through iterative adjustments, the wavelet's phase, polarity, and frequency spectrum were refined to achieve the

highest correlation coefficient, ensuring an accurate tie between the synthetic and real seismic data.

The final extracted wavelet was zero-phase, band-limited, and representative of the seismic bandwidth around the reservoir interval. Using this calibrated wavelet, a synthetic seismic section was generated for each well to validate the time–depth alignment and seismic character of the reservoir zones.

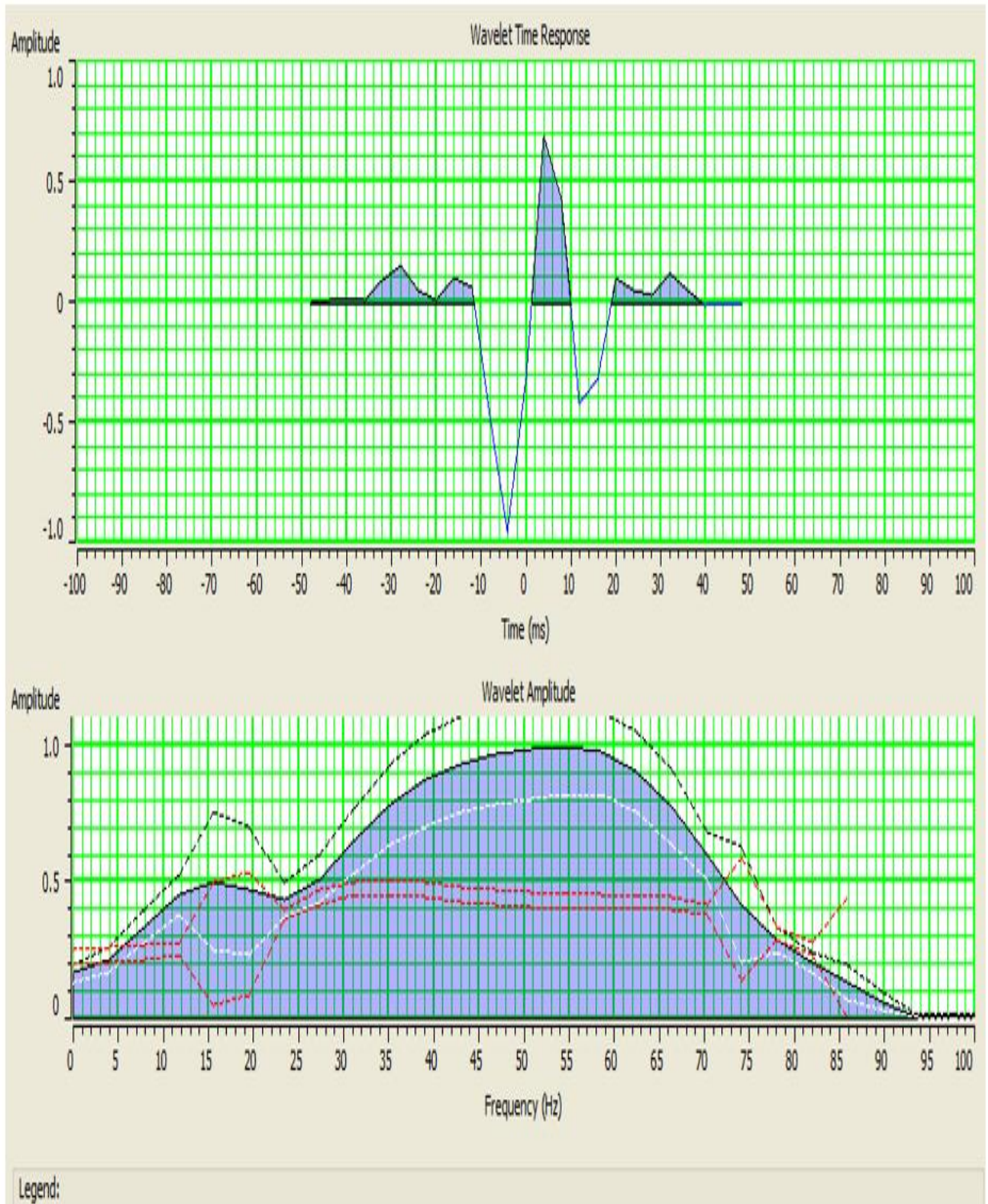


Figure 4.28: Extracted deterministic wavelet.

This deterministic wavelet extraction provided a robust basis for post-stack inversion, as it ensured that the inversion inputs were phase-consistent and amplitude-balanced. The resulting synthetic ties confirmed the accuracy of the seismic-to-well correlation, significantly enhancing the reliability of the inversion results and improving the prediction of lithological and fluid variations. Ultimately, this process contributed to better reservoir delineation and well placement in the undrilled area of TOKS Field.

Wavelet extract revealed maximum correlation of 0.15, 0.69 and 0.10 respectively for TOKS Well 14, TOKS Well 15 and TOKS Well 16 respectively (Figure 4.28 and Figure 4.31). The inversion analysis revealed a high correlation of 0.997866 between the original seismic data and the synthetic seismic trace. Seismic prediction error estimated was very low about 0.0660774, boosting the simulation confidence level.

Well-Seismic Tie

The well-seismic tie is a critical step in the post-stack seismic inversion workflow of TOKS Field using Hampson Russell software, as it establishes a direct relationship between well log data and seismic reflections. This process ensures that the geological and petrophysical information derived from wells is accurately positioned in the seismic time domain, enabling reliable calibration and inversion.

For this study, checkshot-corrected sonic (DT) and density (RHOB) logs from TOKS Wells 14, 15, and 16 were imported into Hampson Russell's Well module. The logs were used to compute acoustic impedance and reflection coefficients, which were then convolved with the previously extracted deterministic wavelet to generate synthetic seismic traces. These synthetic traces represent the expected seismic response of the subsurface at each well location.

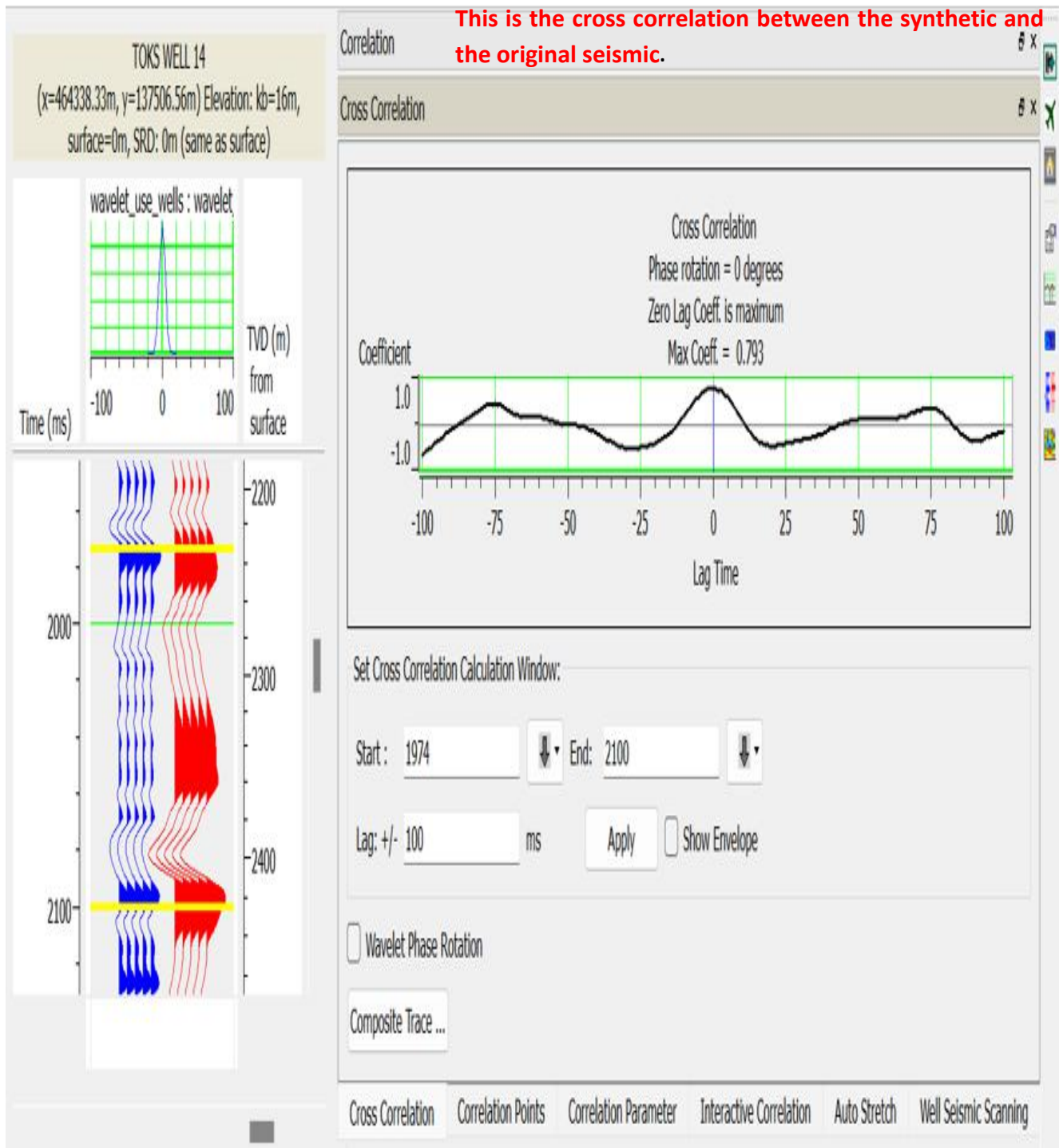


Figure 4.29: Well-to-seismic tie on the left and the cross correlation between the synthetic trace and the original seismic. Note: The blue trace is the synthetic seismic and the red trace is the original seismic.

The synthetic seismograms were visually and statistically compared with the corresponding field seismic traces along the well trajectories. Iterative adjustments were made to fine-tune the time-depth relationship, phase, and polarity until optimal correlation coefficients 0.793 were achieved. This ensured an accurate alignment between seismic events and true stratigraphic markers.

Acoustic impedance was observed to increase with depth, with anomalous areas revealing a reverse in acoustic impedance value (Figure 4.28 and Figure 4.31)

A successful well-to-seismic tie provided the foundation for accurate wavelet extraction, low-frequency model construction, and post-stack inversion calibration. It also confirmed the reliability of the seismic amplitudes in representing true subsurface impedance contrasts. The well-tied seismic sections enhanced the interpretation of reservoir continuity, facies distribution, and fluid variation, particularly in undrilled areas of TOKS Field. Consequently, the well-to-seismic tie significantly improved confidence in the inversion results and guided optimal well placement for efficient field development and hydrocarbon recovery.

Building Low-Frequency Model

The post-stack seismic inversion of TOKS Field using Hampson Russell software, constructing a low-frequency model (LFM) was an essential step to provide the background impedance trend that compensates for the band-limited nature of seismic data. Since seismic frequencies typically range between 10–80 Hz, they lack the very low frequencies necessary to define the absolute impedance levels. The low-frequency model therefore serves as a structural and geological framework that guides the inversion toward realistic subsurface property estimation.

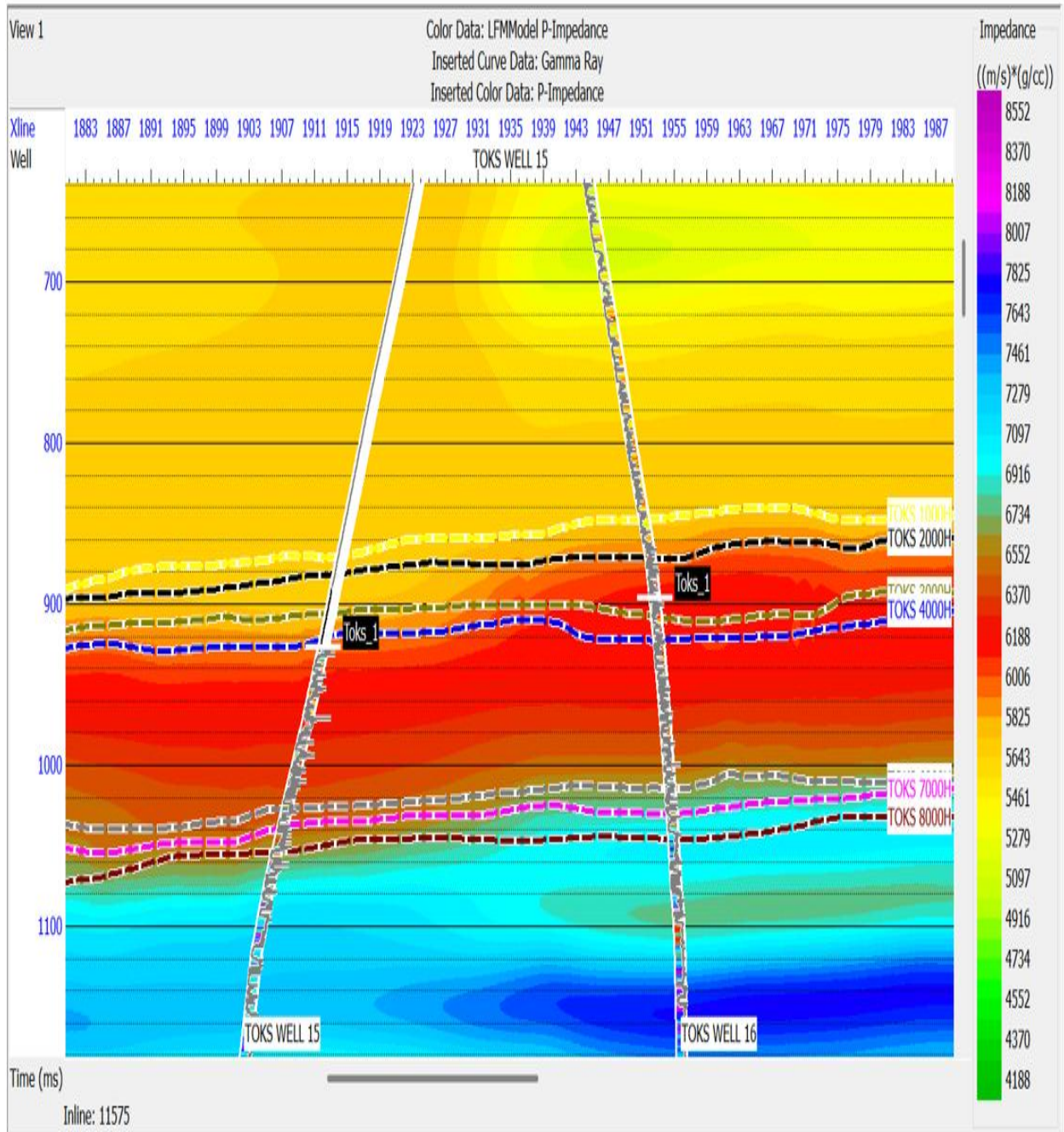


Figure 4.30: Low frequency model generated using the interpreted horizons and well logs as geological constrain.

The model was built using well log-derived acoustic impedance from TOKS Wells 14, 15, and 16, which were previously calibrated through sonic and density logs. The impedance values were converted to the seismic time domain using checkshot-corrected time–depth relationships to ensure alignment with the seismic dataset. In Hampson Russell’s Model module, the impedance logs were interpolated laterally between wells, constrained by the key seismic horizons (TOKS_200H, TOKS_500H, and TOKS_700H) that define the reservoir units. This interpolation generated a spatially consistent impedance trend representing the regional geological layering.

The LFM was merged with the seismic data to restore the missing low-frequency content, ensuring that the final inversion results reflected both seismic amplitude variations and the underlying geological trends. The model was further refined through iterative QC to ensure consistency with structural and petrophysical information.

A robust low-frequency model significantly improved the stability and accuracy of the inversion outputs, reducing uncertainty in impedance estimation and enhancing the delineation of lithological and fluid boundaries. In TOKS Field, this ensured more reliable reservoir characterization and contributed to precise well placement in the undrilled location for optimal hydrocarbon recovery.

Post-Stack Inversion Analysis for Acoustic Impedance

The post-stack seismic inversion analysis for TOKS Field was carried out using Hampson Russell software to transform seismic reflection amplitudes into quantitative acoustic impedance (AI) models for improved reservoir characterization and well placement in undrilled areas. Unlike conventional seismic interpretation, which relies mainly on amplitude and structural

mapping, post-stack inversion provides a more direct relationship between seismic data and subsurface rock properties, allowing better discrimination of lithology and fluid content.

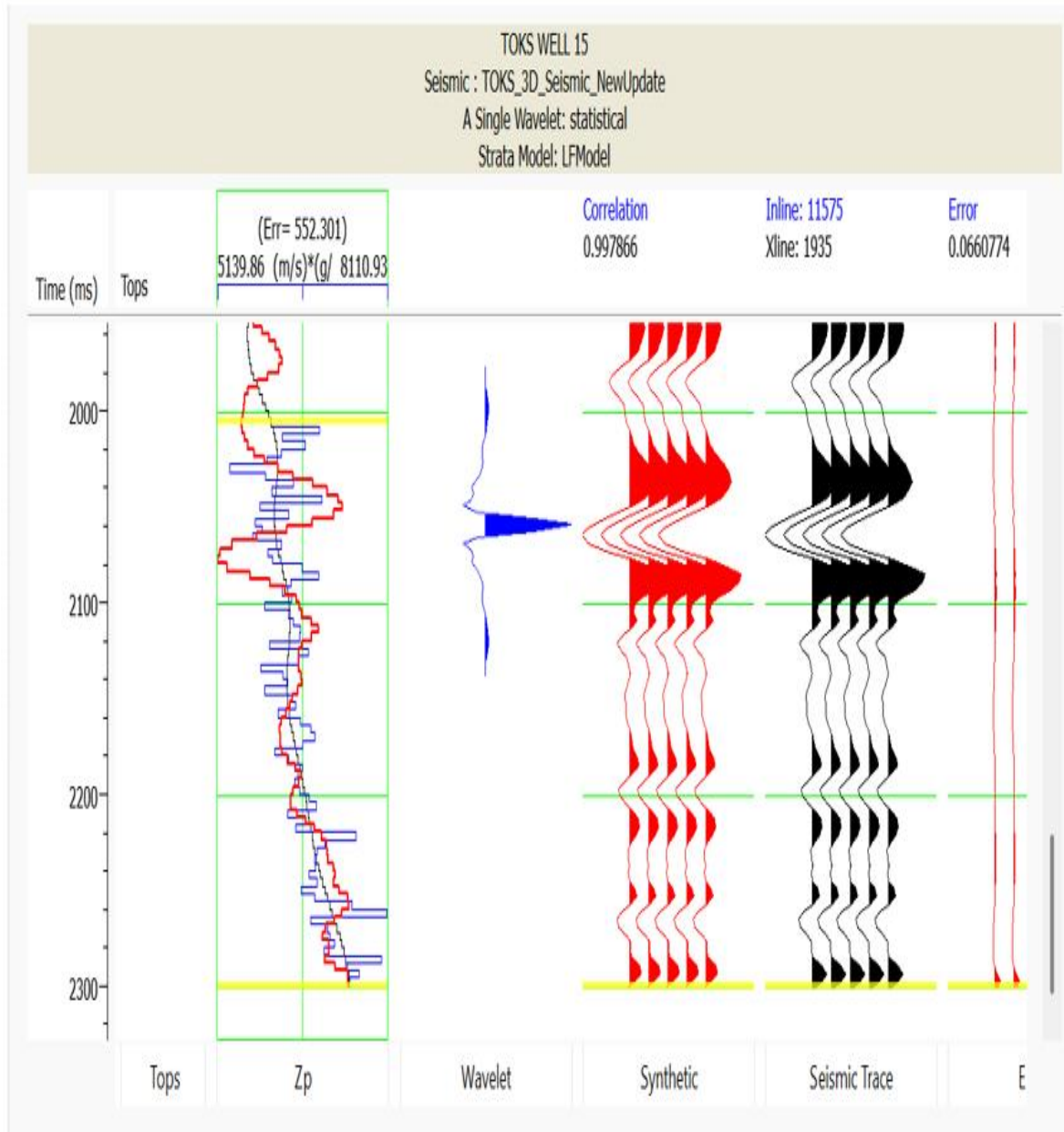


Figure 4.31: The initial model and the extracted deterministic wavelet was used as an input to build a inversion analysis synthetic seismic trace shown in the next slide and then, we compare the synthetic trace with the original seismic trace. Blue Zp: It is from the well data. Black Zp: It is from the Initial low frequency model. Red Zp: It is the Inverted log that will be generated from the inversion. That is, if we run the inversion with the same parameters, we used for the inversion analysis this inverted log is what we will generate at the well location.

The inversion process began with the integration of pre-conditioned 3D post-stack seismic data, well logs (sonic and density), and a deterministic wavelet extracted from the seismic volume. The calibrated wells (TOKS 14, 15, and 16) and their corresponding low-frequency impedance model served as the foundation for building a geologically constrained inversion framework. In Hampson Russell's Inversion module, the seismic traces were inverted using a model-based algorithm that iteratively matched the synthetic seismic response to the observed data by minimizing the root-mean-square (RMS) error.

The resulting inverted acoustic impedance cube exhibited higher vertical resolution than the seismic amplitude data, revealing subtle lithological variations and reservoir continuity that were not easily interpretable from seismic amplitudes alone. The impedance sections were cross-validated with well log data to confirm their reliability.

Acoustic impedance was observed to increase with depth, with anomalous areas revealing a reverse in acoustic impedance value (Figure 4.28 and Figure 4.31)

The post-stack inversion results provided enhanced visualization of high-impedance (tight or shale zones) and low-impedance (potential reservoir sand) regions, aiding in the prediction of hydrocarbon-bearing intervals. As shown in Figure 4.32, higher impedance value right below TOKS Well 15 base interpreted horizon with impedance value 4370 – 5461 ((m/s)* (g/cc)) depict probable shale rich areas across the field (deep blue to light blue colour), spread across from West to East of the field while lower impedance which depicts probable sand rich areas (red to brown to yellow to light green colours) fall between 5643 – 8108 ((m/s)* (g/cc)) (Figure 4.71). Inverted acoustic Impedance log distributed across 3-D model showed that much more saturation of prospective hydrocarbon accumulation exists around the areas depicted from

red to brown to yellow to light green colours. Low P-impedance revealed high porosity areas on the model, while shale rich beds were characterized by high impedance values seen between green and blue colours (Figure 4.32). This quantitative analysis improved confidence in mapping reservoir distribution, thickness, and quality, thereby guiding the optimal placement of new wells in the undrilled location of TOKS Field. Ultimately, the inversion outputs formed a critical input for reservoir development and production optimization strategies. The entire results is in consistence with works of Mbou *et al.*, (2024) and Tiekuro *et al.*, (2024).

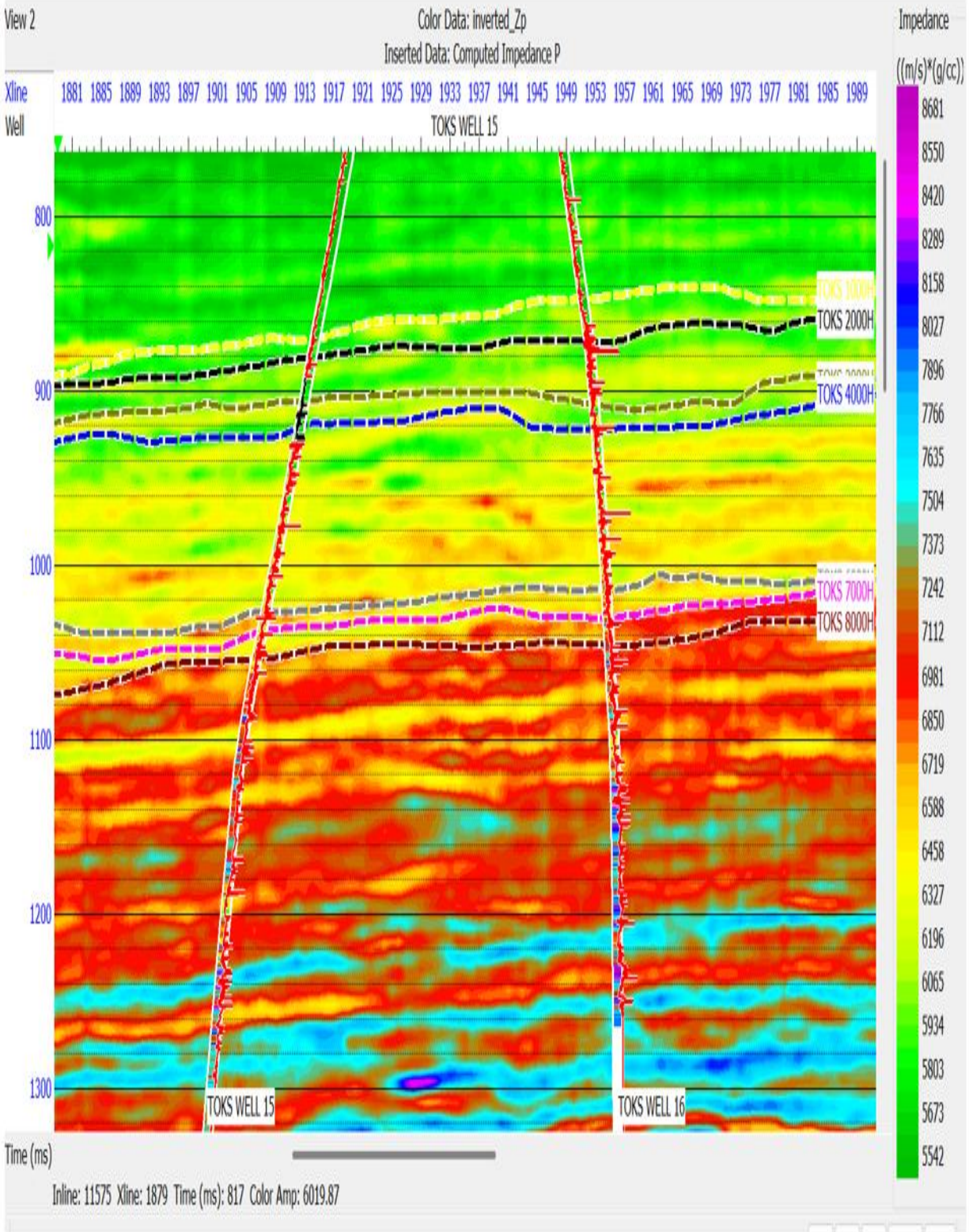


Figure 4.32: Inverted post-stack seismic data acoustic

Post-Stack Inversion Analysis and Generation of Property Cubes

After completing the post-stack seismic inversion analysis of TOKS Field using Hampson Russell software, the inversion process was executed to generate a high-resolution acoustic impedance (AI) cube (Fig 4.34). This cube represents the spatial distribution of acoustic impedance within the reservoir interval and serves as a crucial quantitative dataset for predicting lithological and petrophysical properties across the field, especially in undrilled locations. The AI cube was derived by integrating the seismic data with well log information from TOKS Wells 14, 15, and 16, ensuring that the inversion results were properly constrained by reliable well control and a geologically consistent low-frequency model.

Following the generation of the acoustic impedance cube, cross-plot analyses were performed to derive secondary property cubes that enhance reservoir understanding and hydrocarbon prediction. The first cross-plot involved acoustic impedance versus porosity derived from well log data.

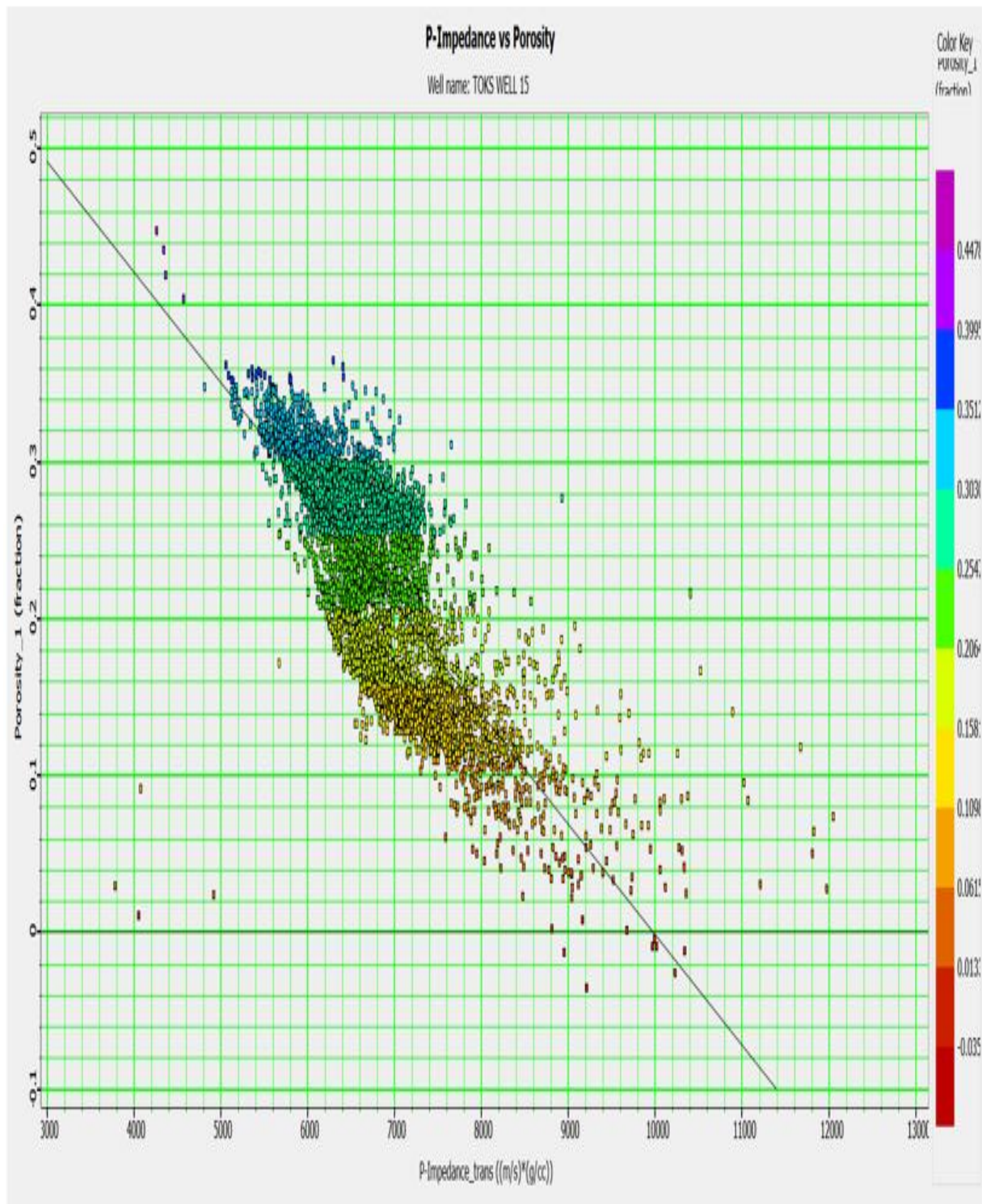


Figure 4.33: Acoustic impedance (AI) log versus porosity

The relationship showed a distinct inverse correlation—zones with low acoustic impedance corresponded to high porosity (likely sand units), while zones with high impedance indicated low porosity (likely shale units). Using this relationship, a porosity cube was generated, providing a continuous spatial estimate of porosity distribution throughout the seismic volume. This cube is vital for identifying high-quality reservoir zones with good storage capacity and fluid flow potential. Tiekuro *et al.*, (2024).

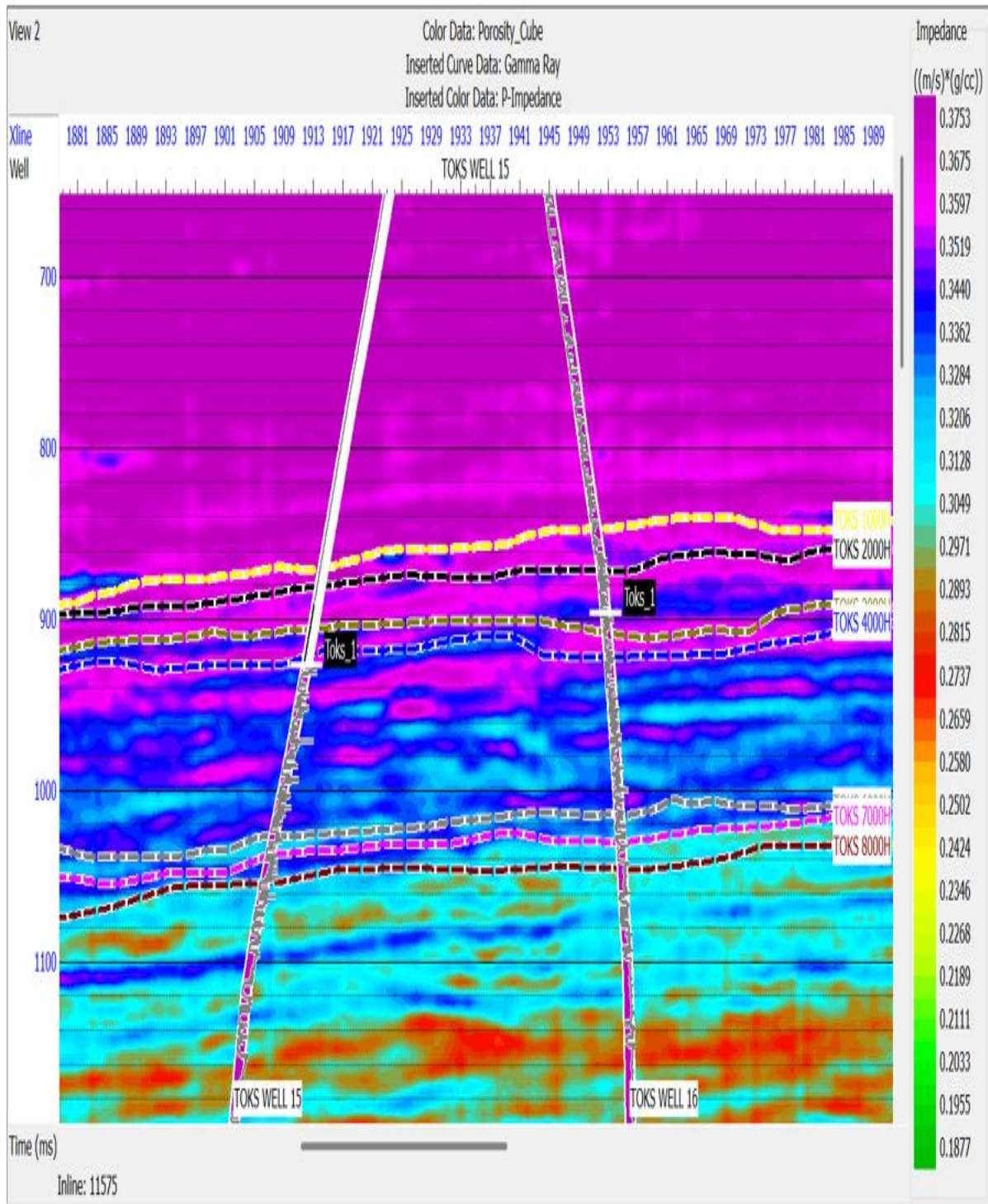


Figure 4.34: Generated porosity cube

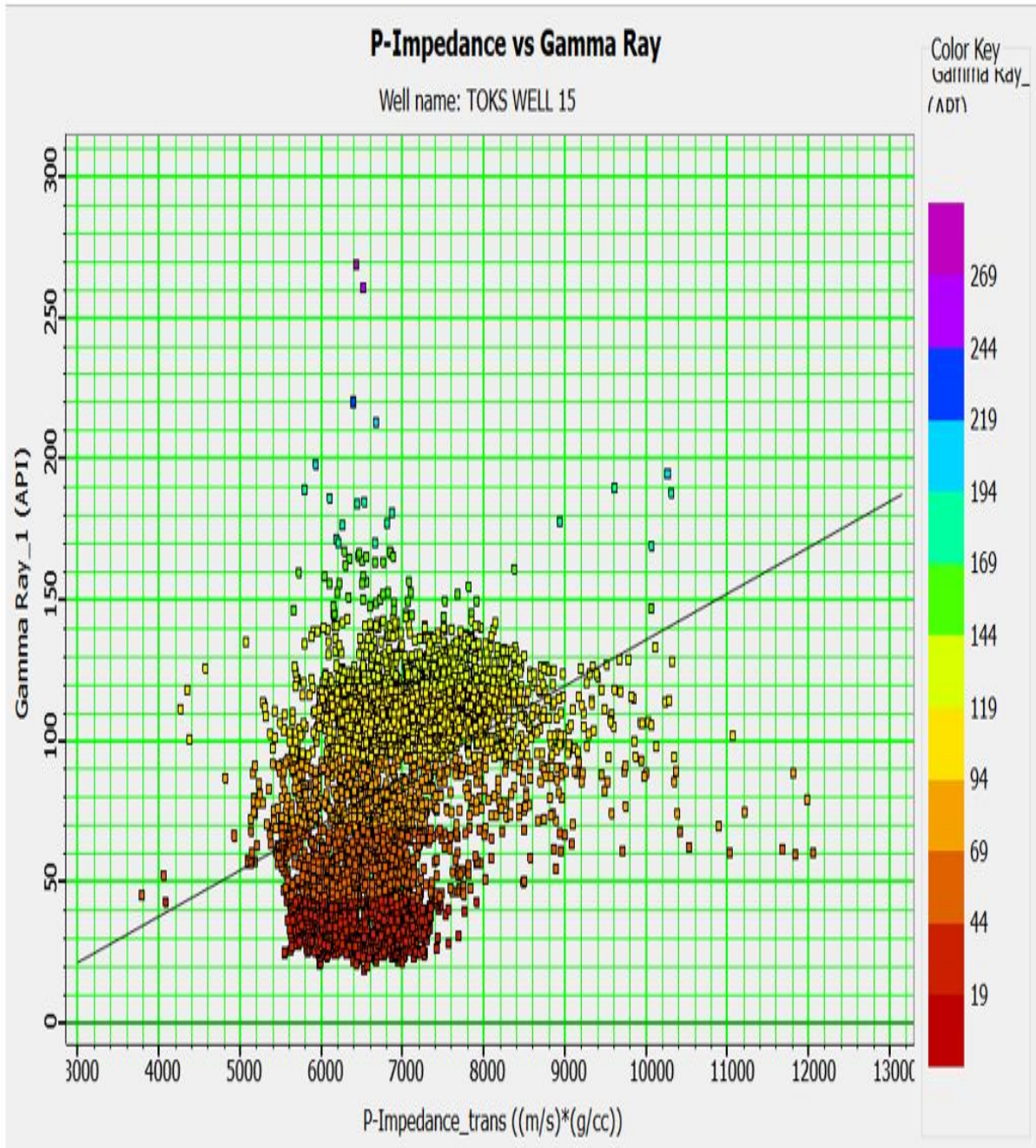


Figure 4.35: Acoustic impedance (AI) log versus gamma ray log cross-plot

Since gamma ray values reflect shale content, areas of low gamma ray and low impedance typically indicate clean sand formations, while high gamma ray and high impedance zones represent shale or non-reservoir formations. Based on this relationship, a gamma ray cube was created from the inverted impedance data.

The gamma ray cube successfully highlighted lithological variations across the field, distinguishing sand-dominated intervals from shale-dominated layers. When compared to the porosity cube, the gamma ray cube showed excellent agreement, confirming the consistency of the inversion results and strengthening confidence in the identified sand and shale distributions.

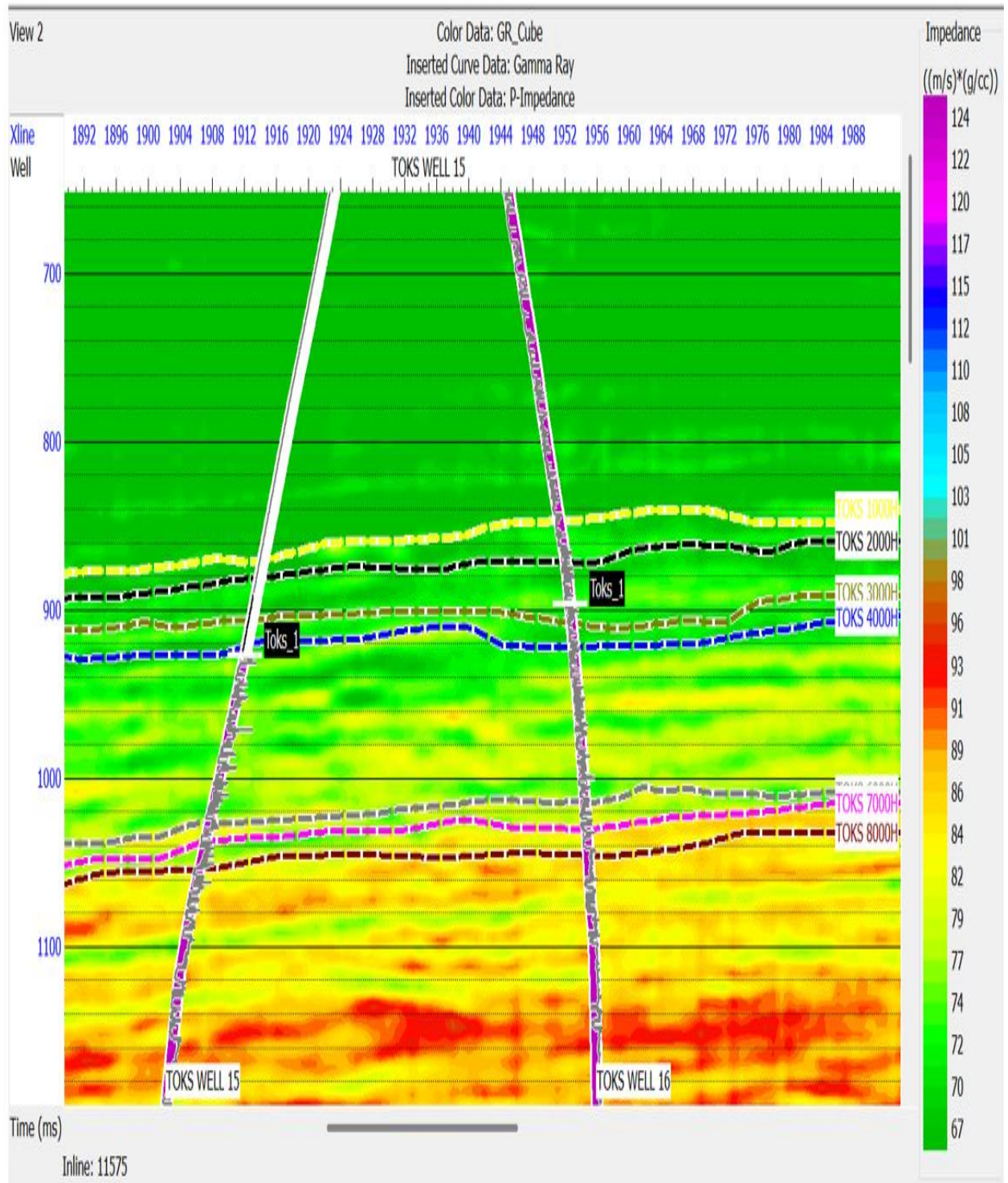


Figure 4.36: Generated gamma ray cube

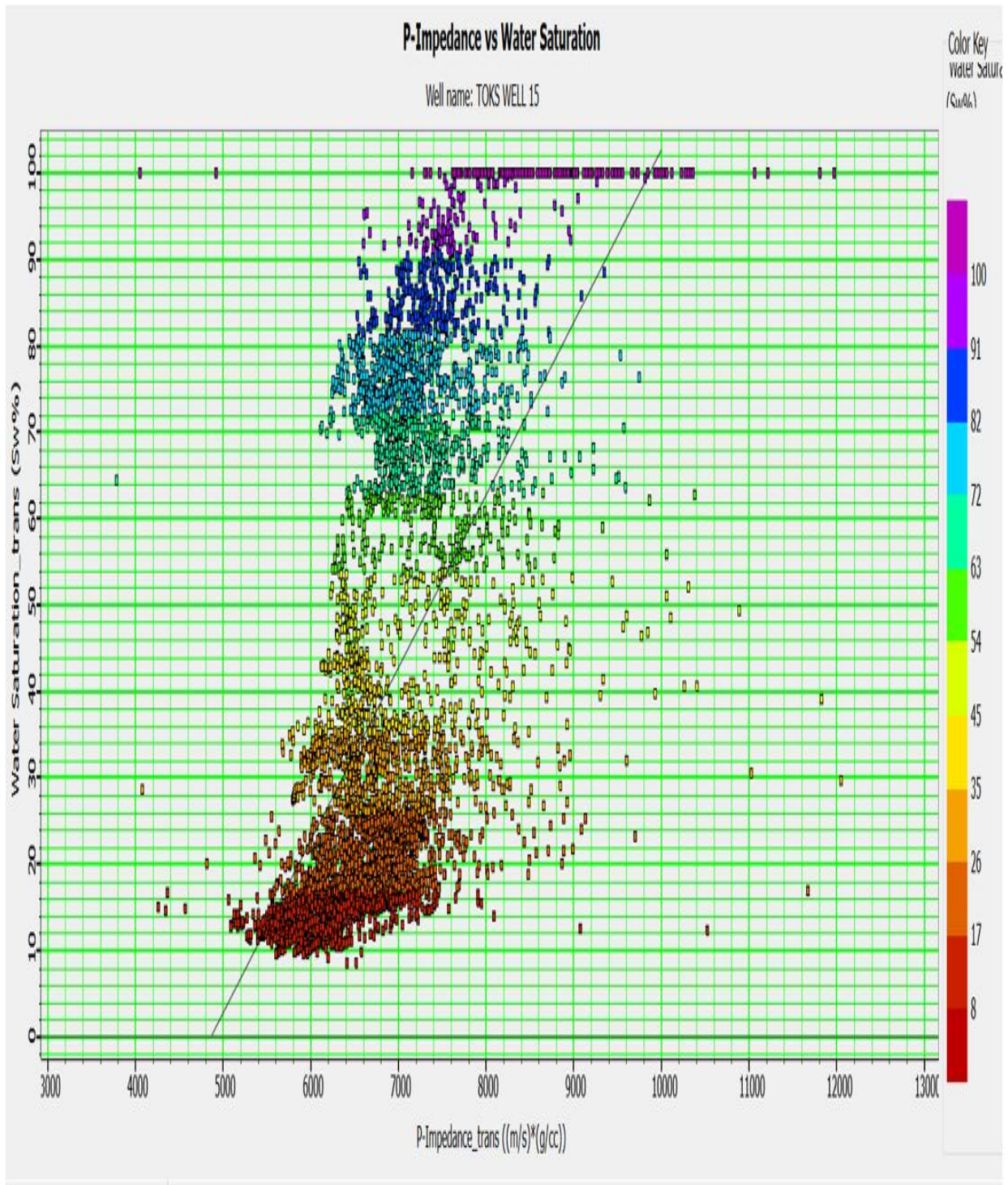


Figure 4.37: Acoustic impedance (AI) log versus water saturation log cross-plot.

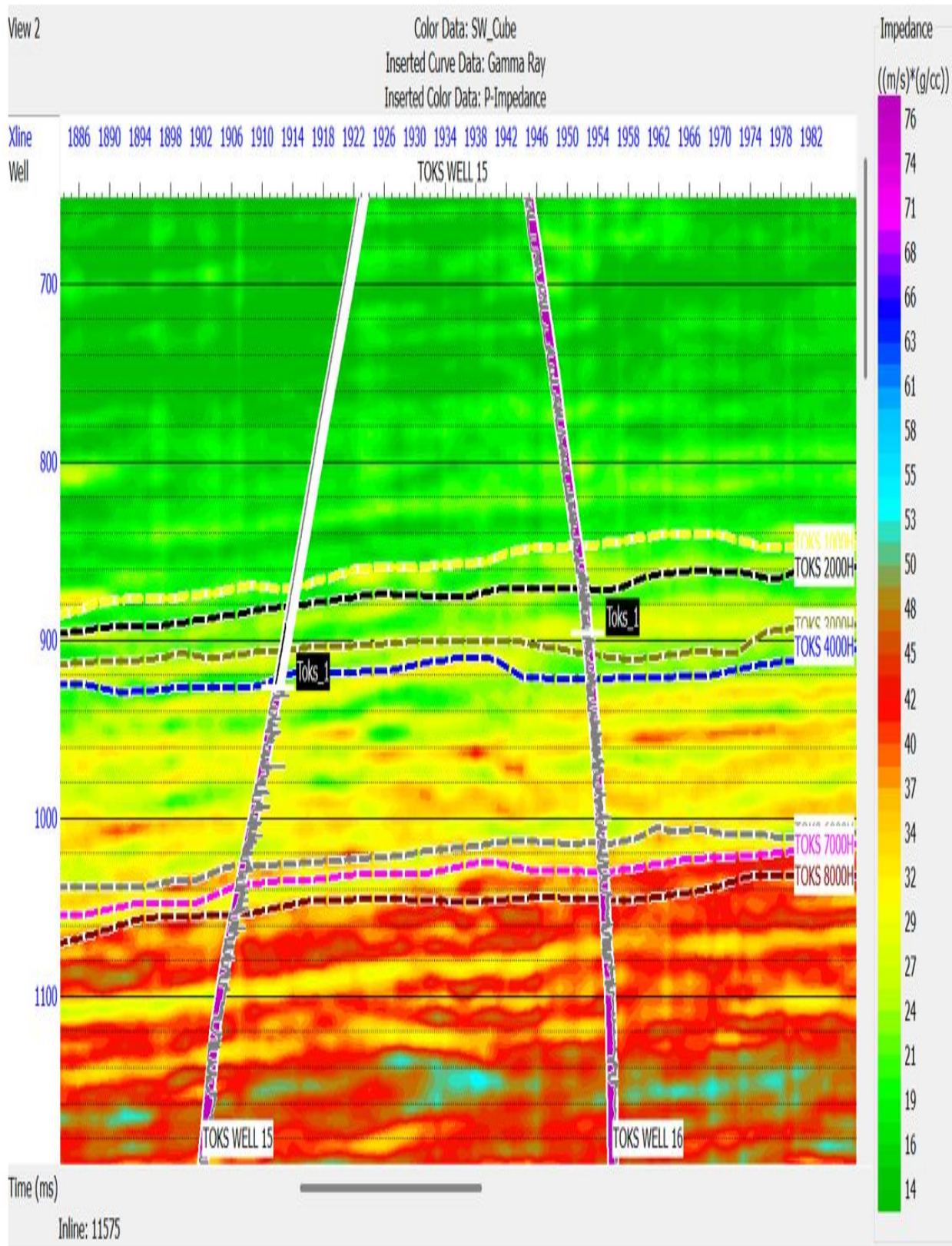


Figure 4.38: Shows the generated water saturation cube.

Typically, zones with lower impedance values correspond to hydrocarbon-bearing sands due to lower fluid density and velocity, whereas zones with higher impedance values correspond to water-saturated formations. This relationship was used to derive a water saturation cube, which provides a volumetric representation of fluid content within the reservoir interval. The water saturation cube clearly delineated areas of high-water saturation and low water saturation, the latter being potential hydrocarbon-bearing zones.

A comparative analysis of the porosity cube, gamma ray cube, and water saturation cube showed remarkable consistency and correlation. High-porosity, low-gamma ray, and low-water saturation zones were observed to coincide spatially, strongly indicating the presence of hydrocarbon-bearing sand bodies. Similarly, regions characterized by low porosity, high gamma ray, and high-water saturation corresponded to shale or non-reservoir zones. This integrated interpretation confirmed the reliability of the inversion-derived property cubes in accurately characterizing the subsurface.

The generation and integration of these property cubes represent a significant advancement over conventional seismic amplitude interpretation. While traditional methods provide qualitative insights into subsurface structures, post-stack inversion and subsequent property modeling deliver quantitative and high-resolution characterization of the reservoir. The combined interpretation of the acoustic impedance, porosity, gamma ray, and water saturation cubes provided a detailed understanding of lithological variation, reservoir continuity, and fluid distribution across TOKS Field.

These results are particularly valuable for predicting hydrocarbon potential in undrilled locations. By identifying zones of favorable porosity, clean sands, and low water saturation, the

inversion analysis offers a scientifically sound basis for guiding new well placement and field development planning. In areas lacking well control, the property cubes help reduce geological uncertainty by extrapolating rock and fluid properties away from existing wells.

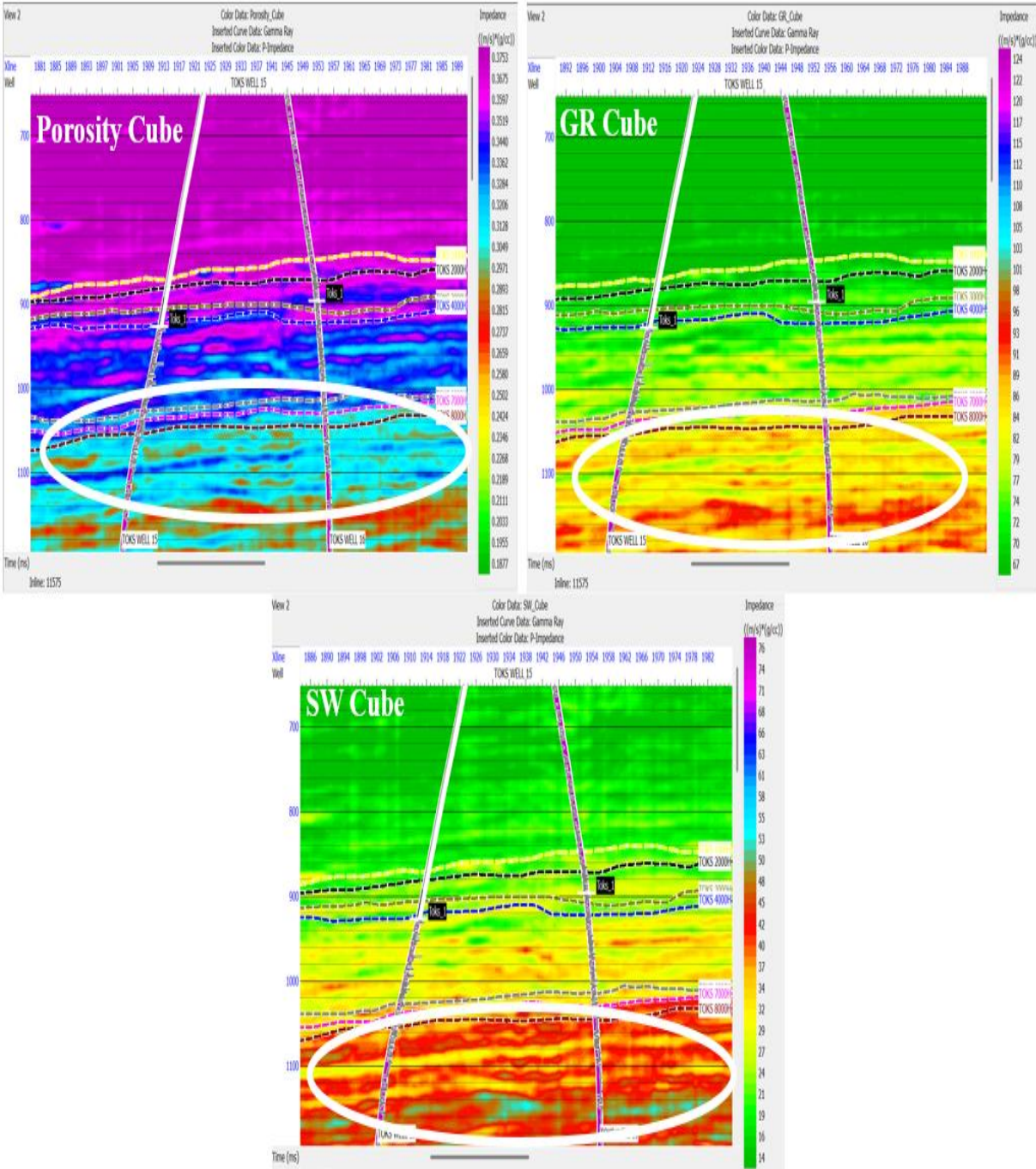


Figure 4.39: Comparison between the generated porosity, gamma ray, and water saturation cubes.

In summary, the post-stack inversion and subsequent cross-plot analysis in Hampson Russell successfully transformed the seismic data of TOKS Field into a series of predictive petrophysical cubes—porosity, gamma ray, and water saturation—that collectively provide a more accurate and comprehensive view of the reservoir. The consistency among these cubes validates the robustness of the inversion workflow and enhances confidence in using the results for hydrocarbon prospect delineation and optimal well placement in undrilled zones. This integrated approach thus serves as a vital step in improving exploration success and maximizing recovery efficiency in TOKS Field.

Horizon Surface

The Horizon Surface of the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria is predicated on figure 4.40.

The 3D Grid of 50 x 50 the Horizon Surface in Depth Domain of the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria is predicated on figure 4.41.

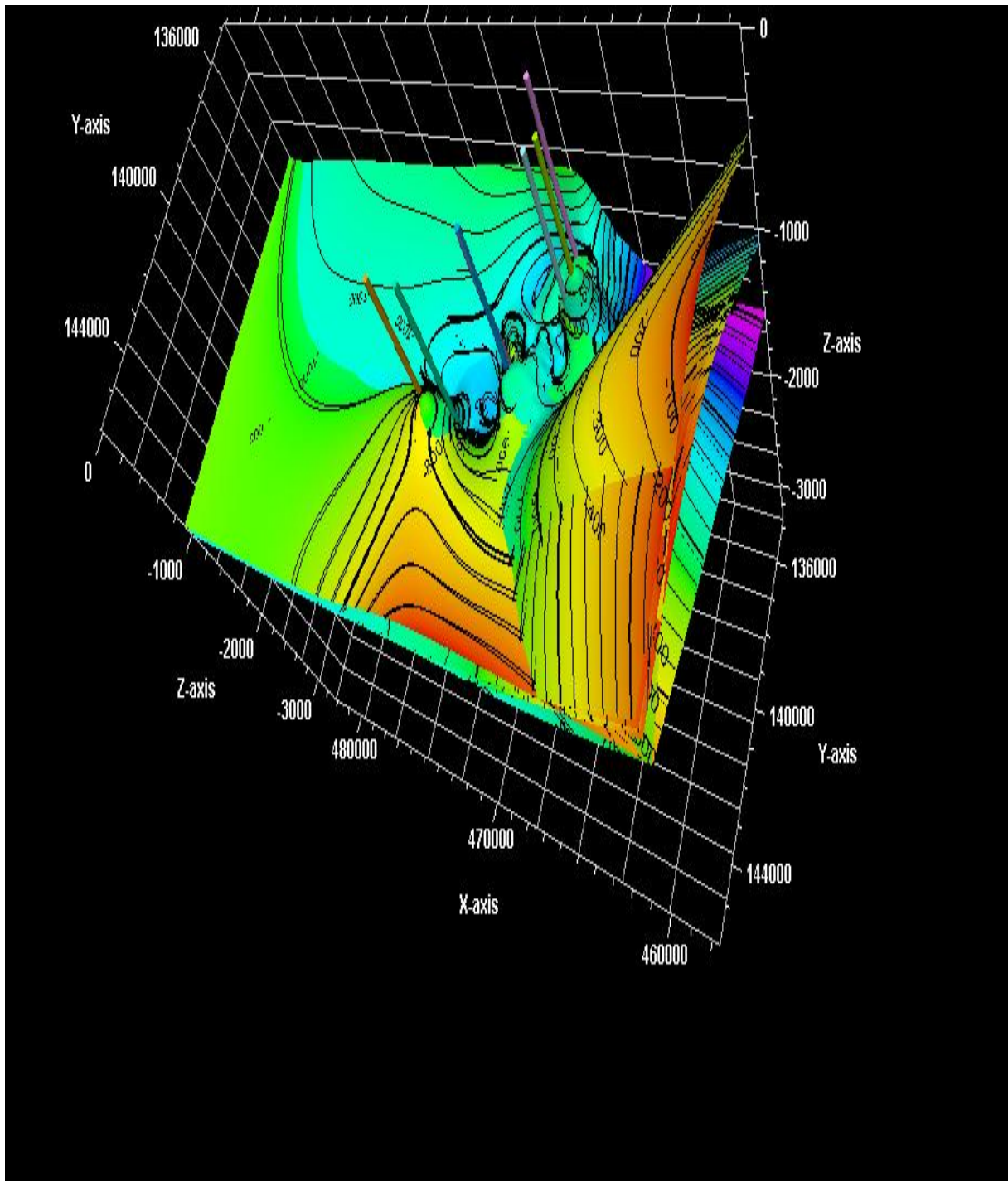


Figure 4.40: Horizon Surface of TOKS wells

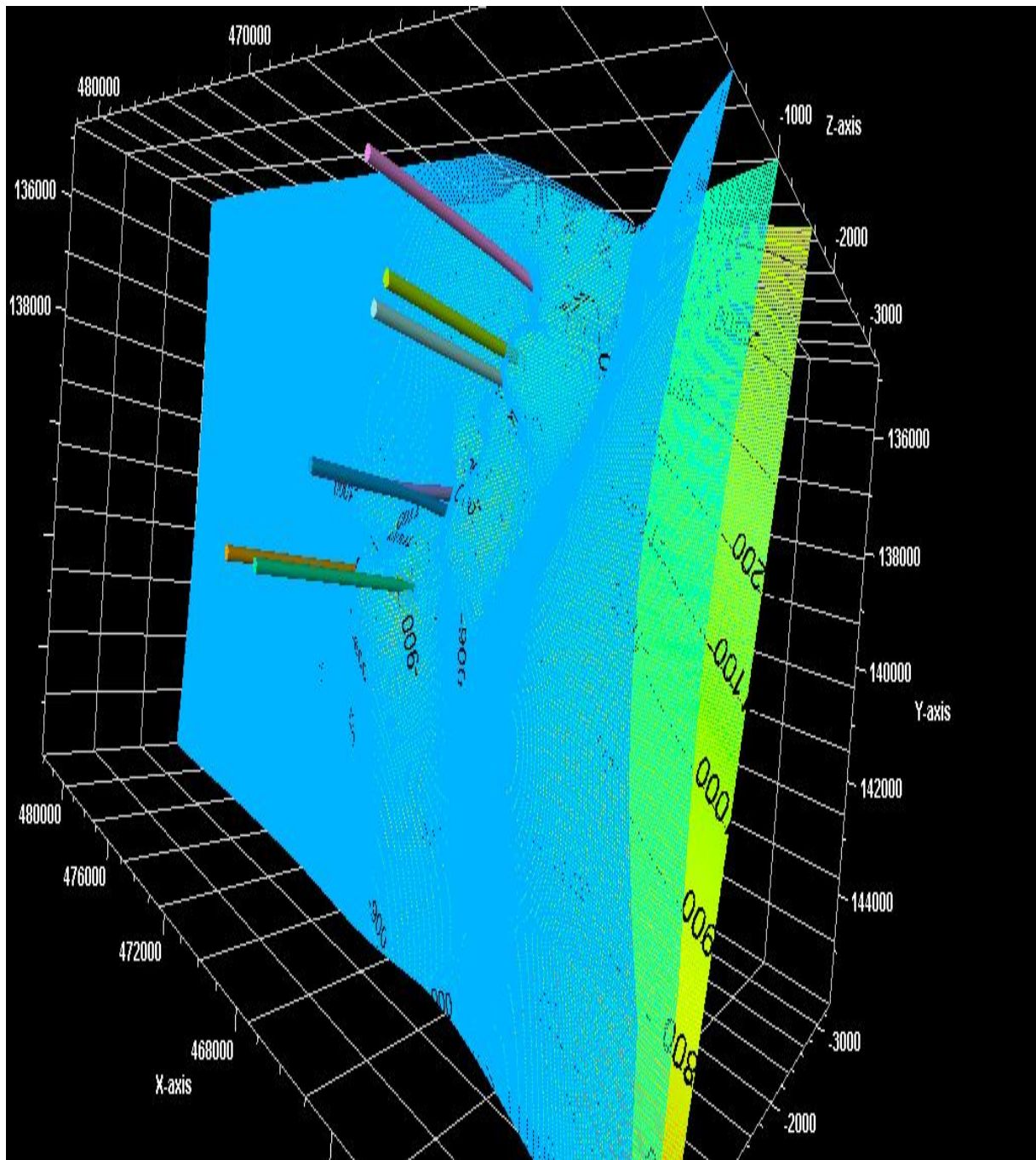


Figure 4.41: Horizon Surface in Depth Domain

Depth Structural Map

The reservoirs' time maps were depth converted using the polynomial function from velocity model and calibrated to the well tops.

The depth structural map of the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria for H1000 is predicated on figure 4.42.

The depth structural map of the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria for H2000 is predicated on figure 4.43.

The depth structural map of the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria for H3000 is predicated on figure 4.44.

The depth structural map of the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria for H4000 is predicated on figure 4.45.

The depth structural map of the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria for H5000 is predicated on figure 4.46.

The depth structural map of the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria for H6000 is predicated on figure 4.47.

The depth structural map of the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria for H7000 is predicated on figure 4.48.

The depth structural map of the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria for H8000 is predicated on figure 4.49.

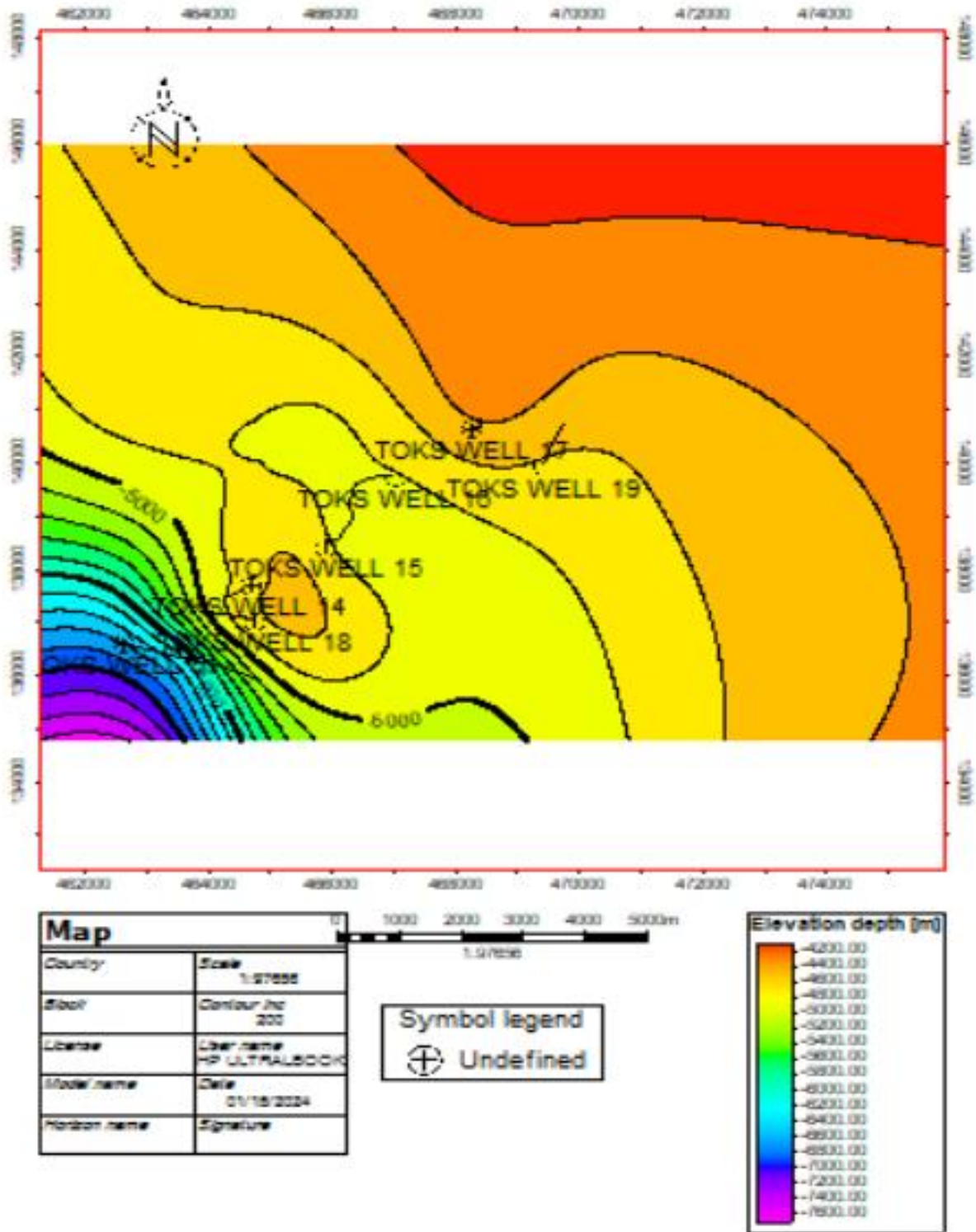


Figure 4.42: Depth Structural Map (H1000)

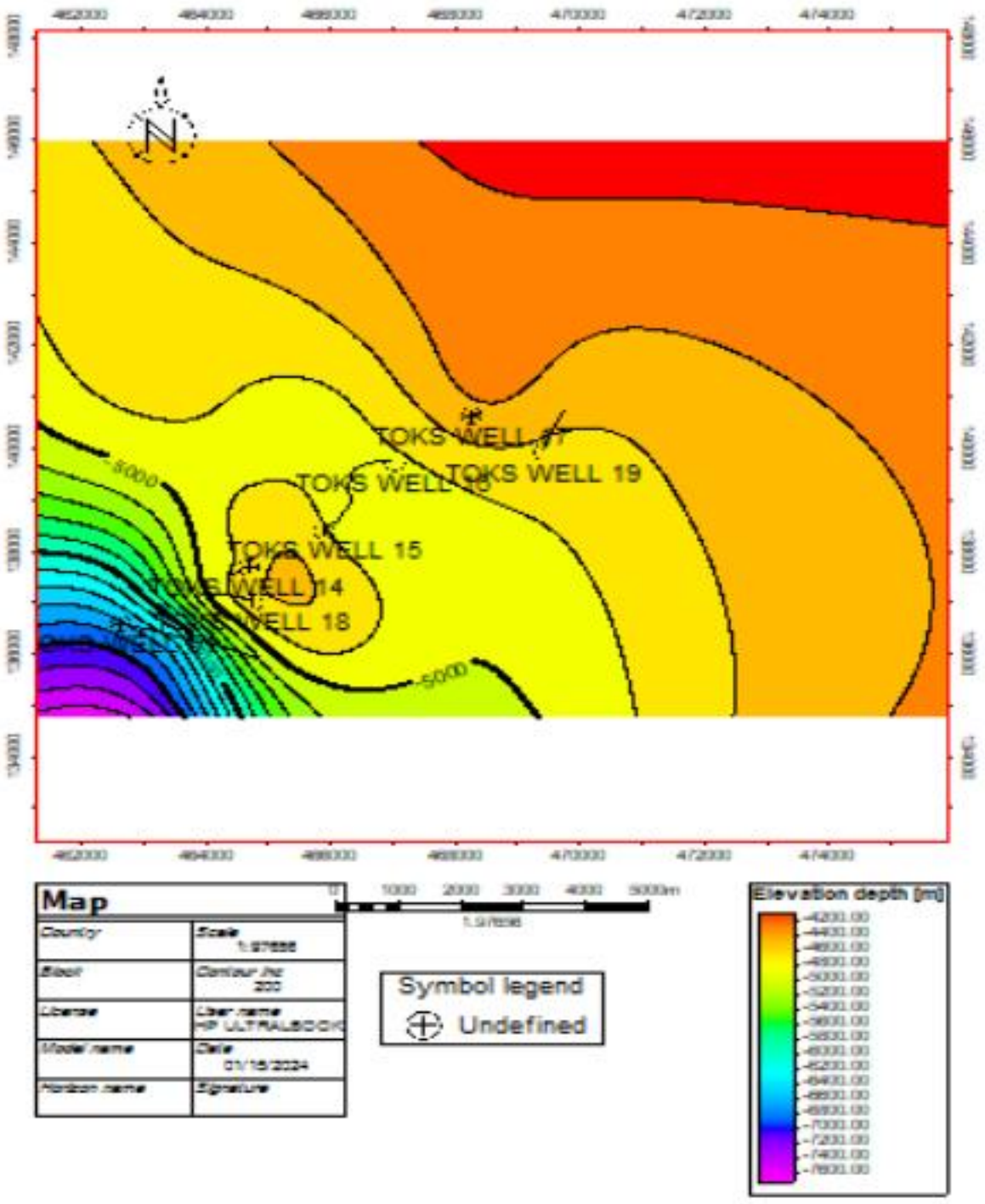


Figure 4.43: Depth Structural Maps (H2000)

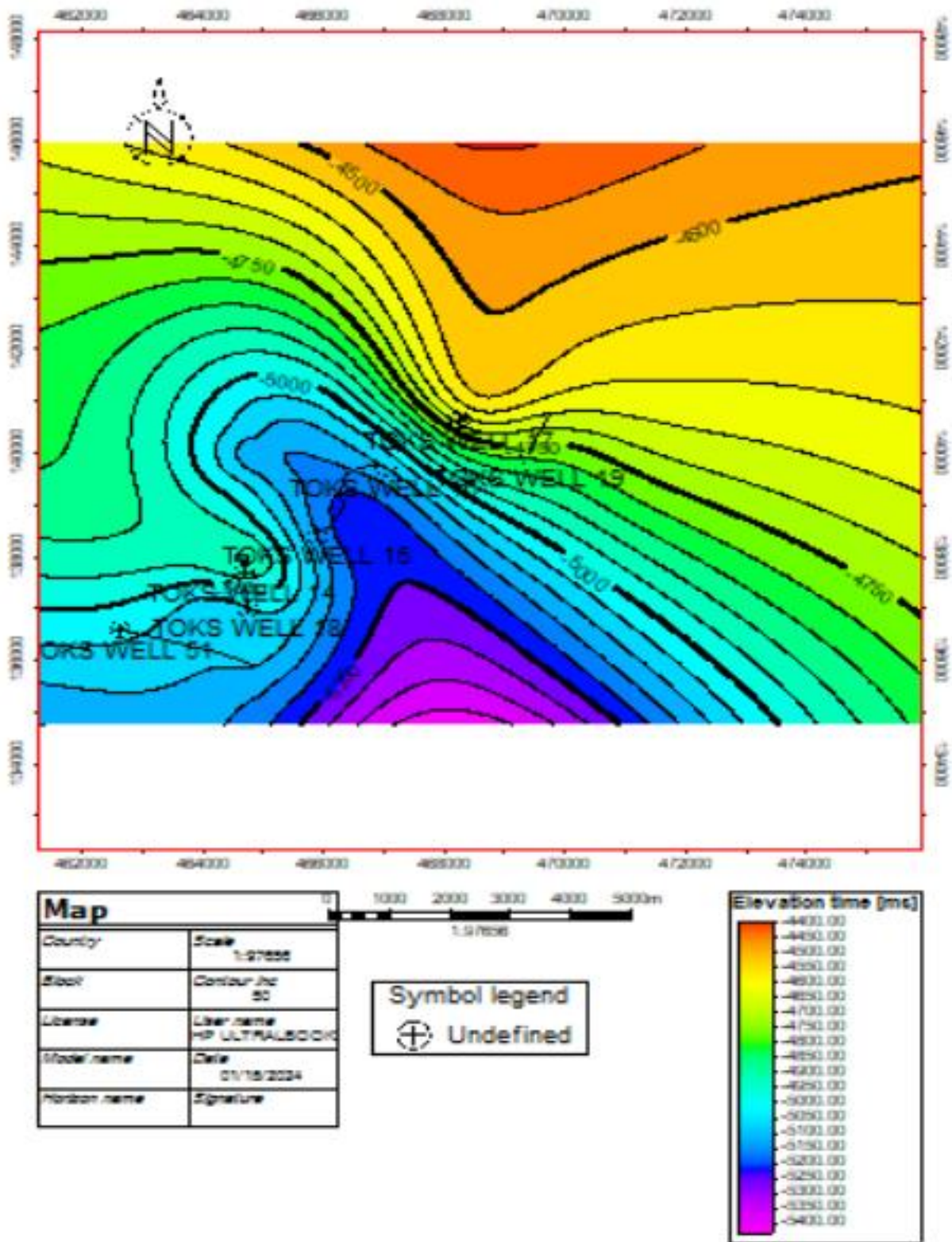


Figure 4.44: Depth Structural Maps (H3000)

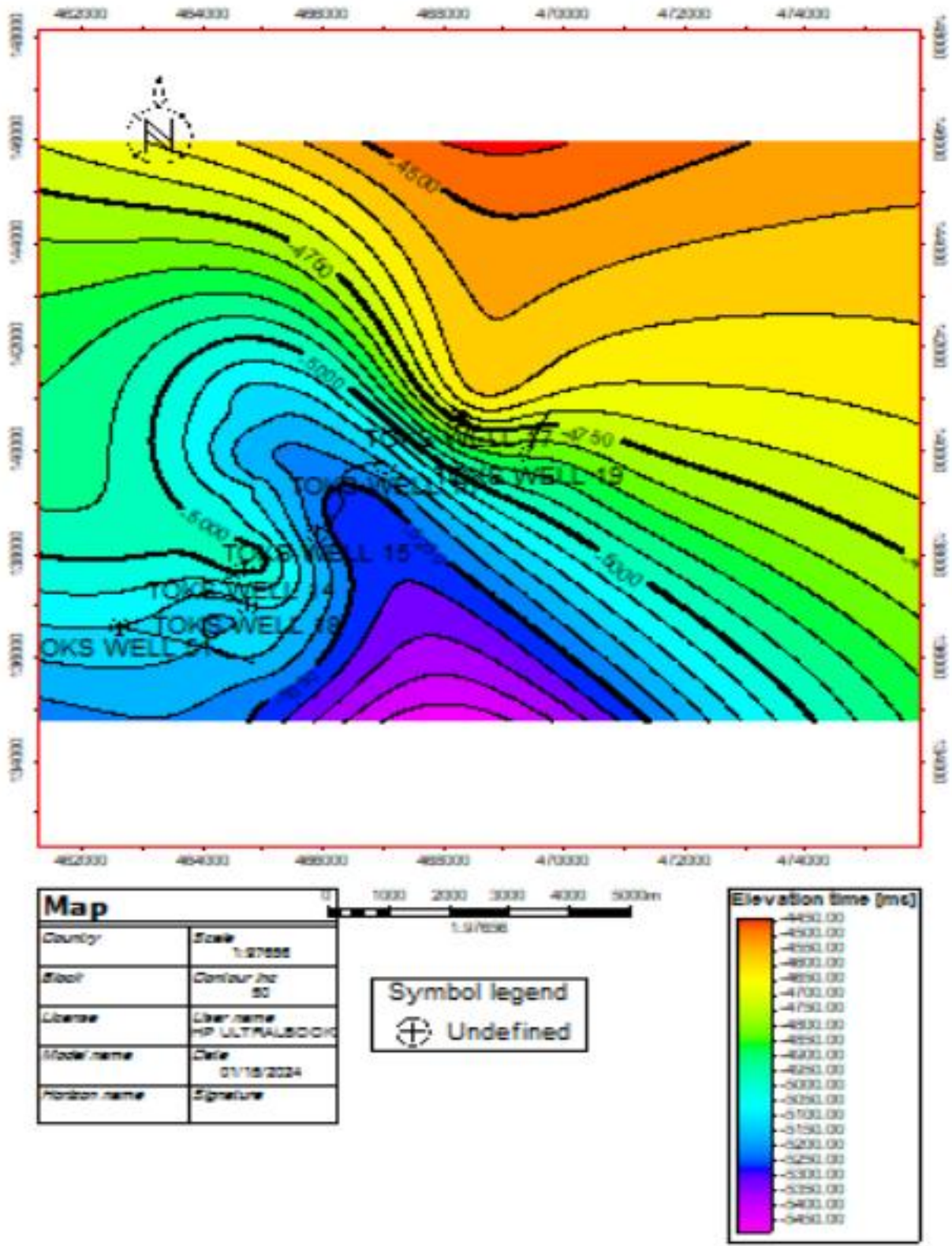


Figure 4.45: Depth Structural Maps (H4000)

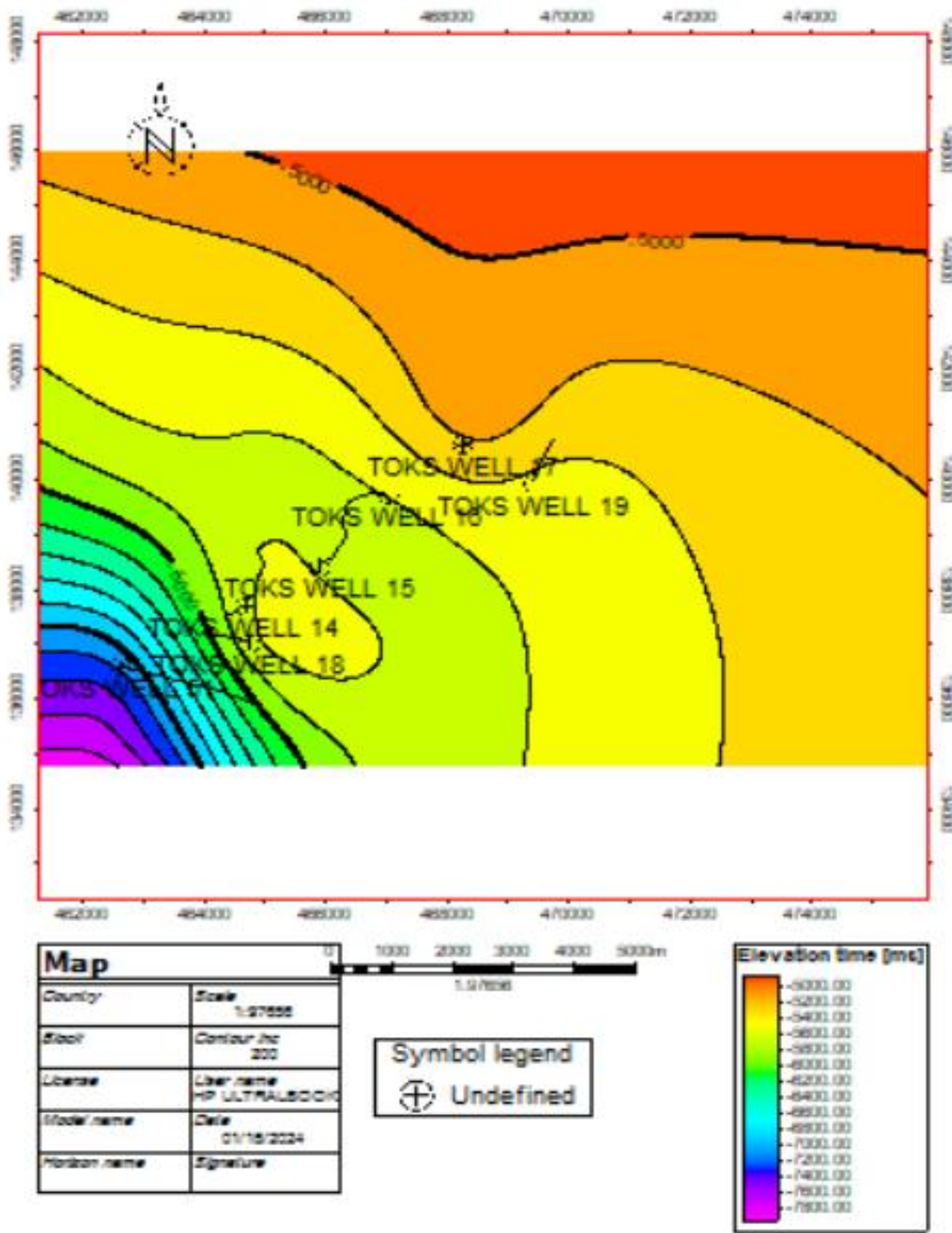


Figure 4.46: Depth Structural Map (H5000)

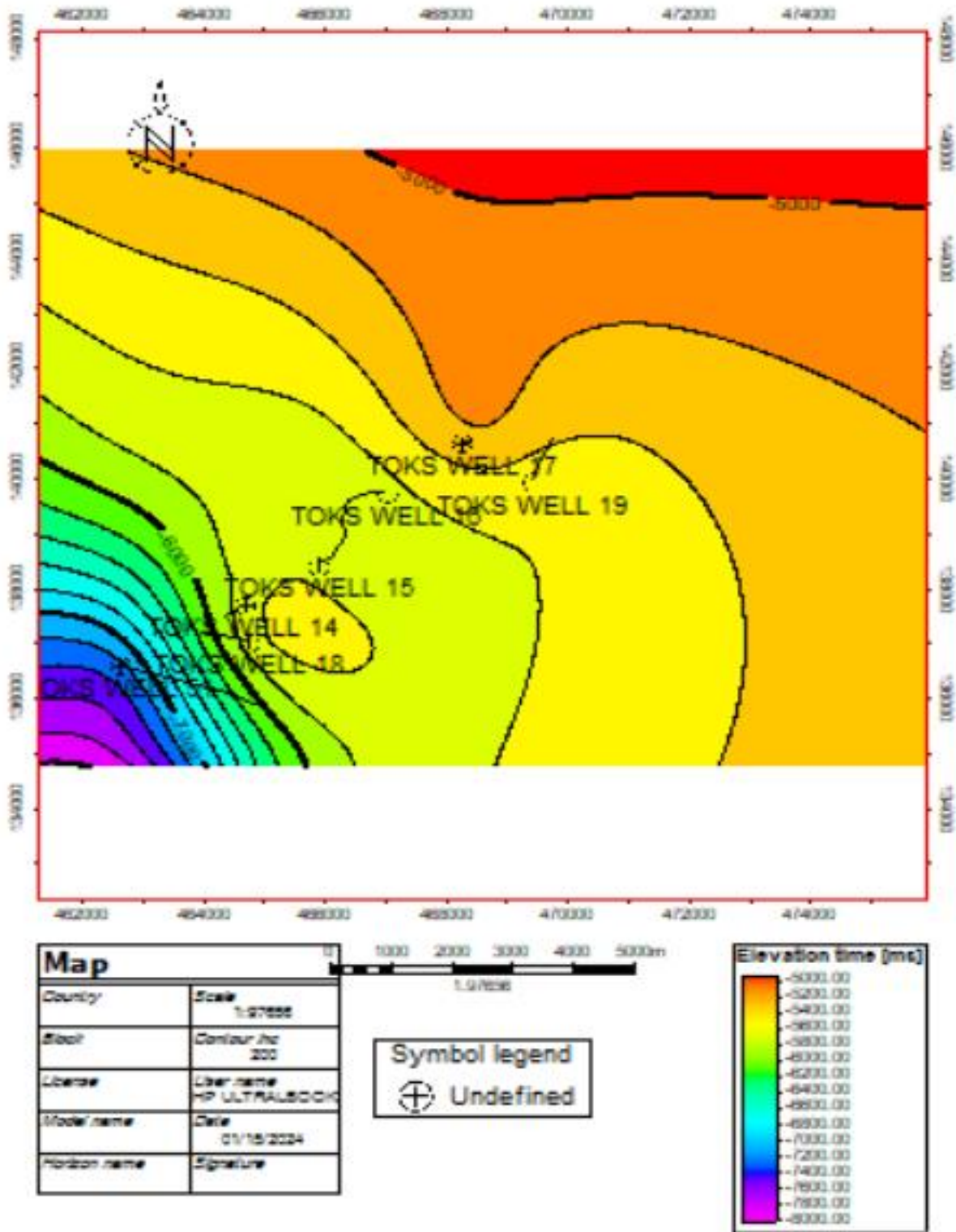


Figure 4.47: Depth Structural Maps (H6000)

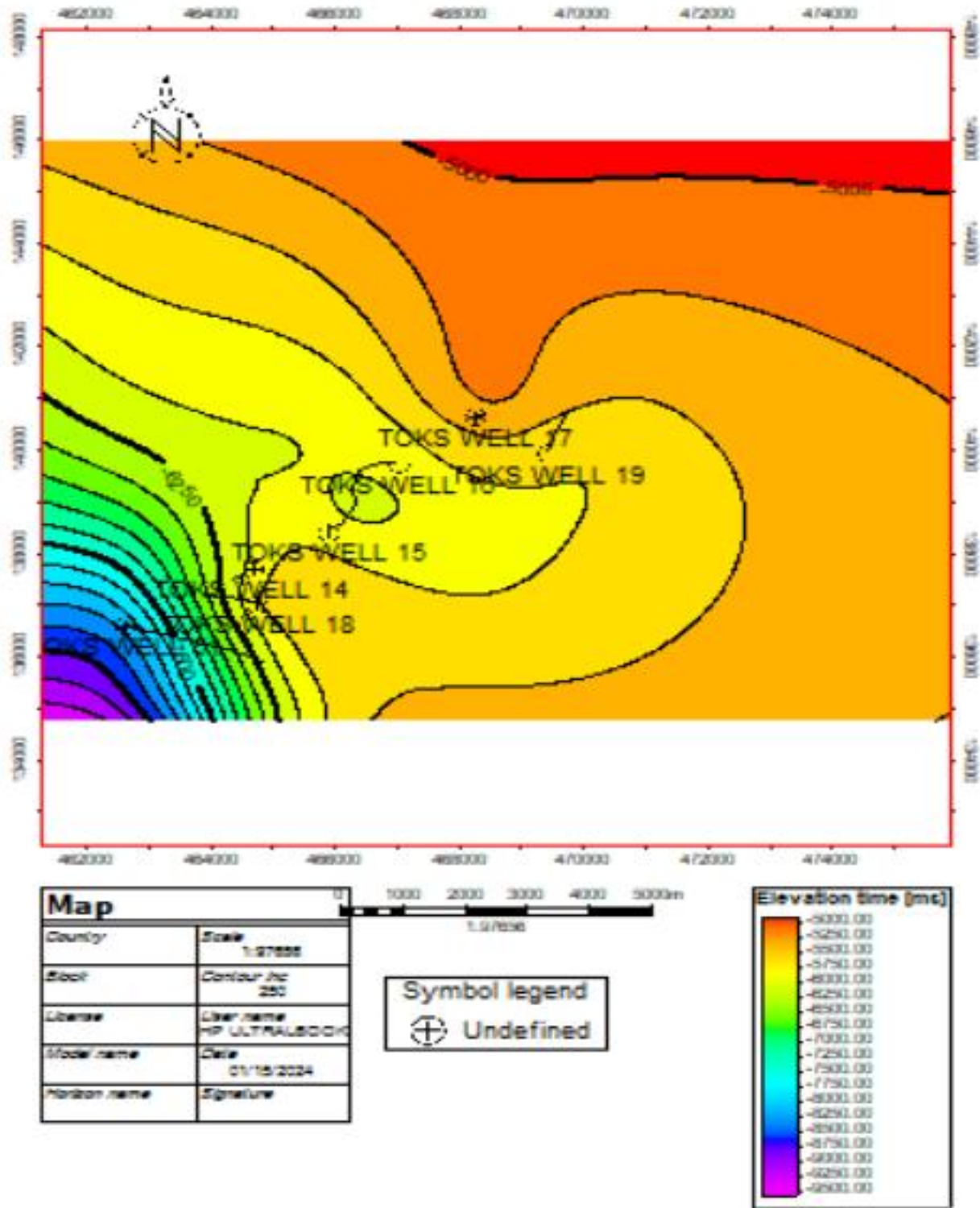


Figure 4.48: Depth Structural Map (H7000)

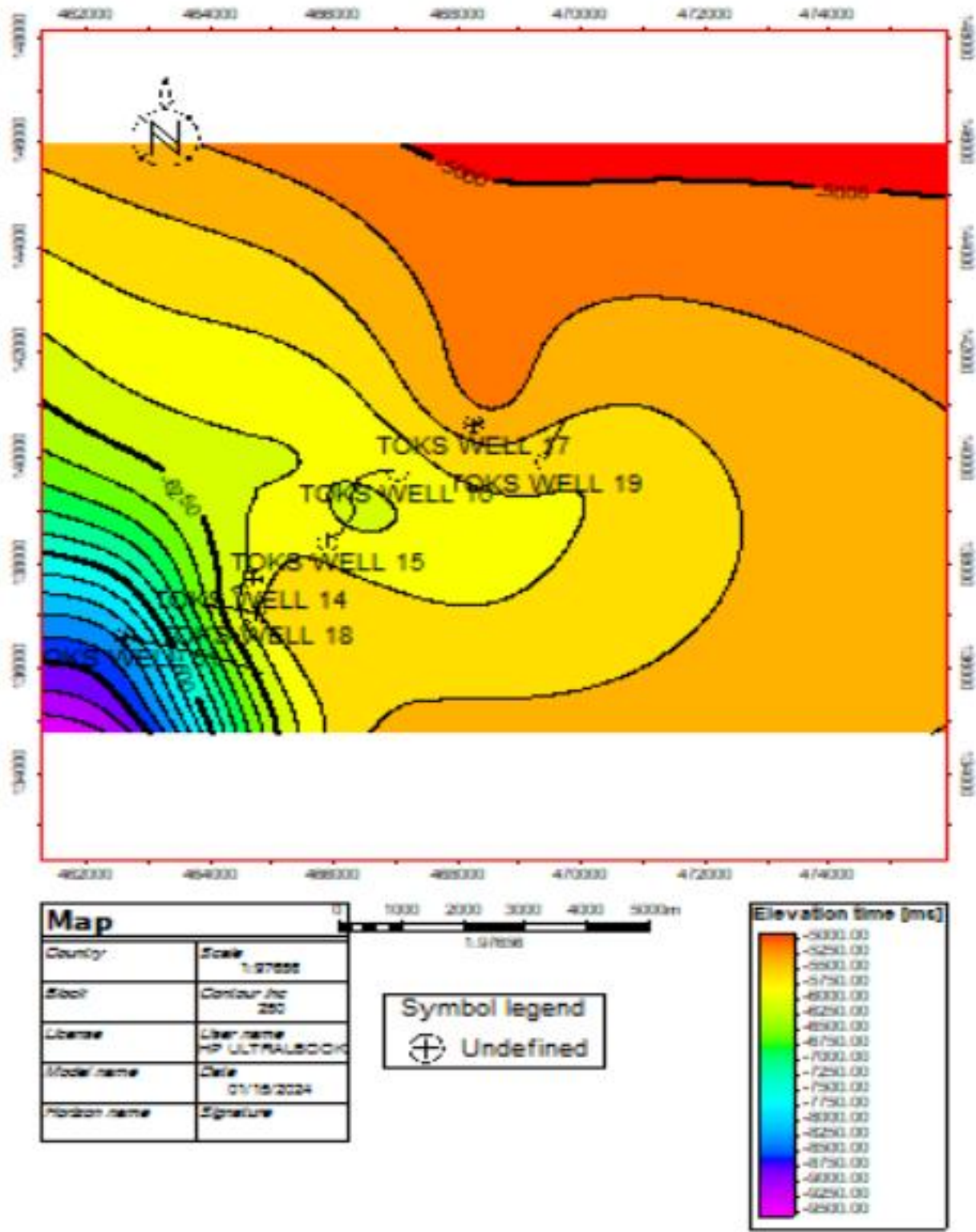


Figure 4.49: Depth Structural Map (H8000)

4.4 RESERVOIR CHARACTERIZATION

The reservoirs in the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria evaluated using various models. This includes structural models, porosity models, water saturation and facies models.

3D reservoir models were built using Petrel workflow tools. Gridding and layering were carried out. The reservoir properties derived from the petrophysical well logs were upscaled into the 3Dgrid in petrel after which data analysis (variogram analysis) was carried out. The geostatistical method used in krigging method in distributing models of the reservoir to produce the petrophysical models using Sequential Indicator Simulation (SIS) Algorithm for facies models, Stochastic Technique – Sequential Gaussian Simulation for NTG models, Stochastic Technique – Sequential Gaussian Simulation for porosity models and Stochastic Technique – Sequential Gaussian Simulation for water saturation models.

Structural Model

The structural model (In Petrel) used for the reservoirs in TOKS field involves Gridding and Horizon Making. The structural model was based on the depth – converted 3D seismic interpretation.

The gridding (skeleton and grid 50X50, 3D reservoir) structural model of the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria is predicated on figure 4.50 and figure 4.51.

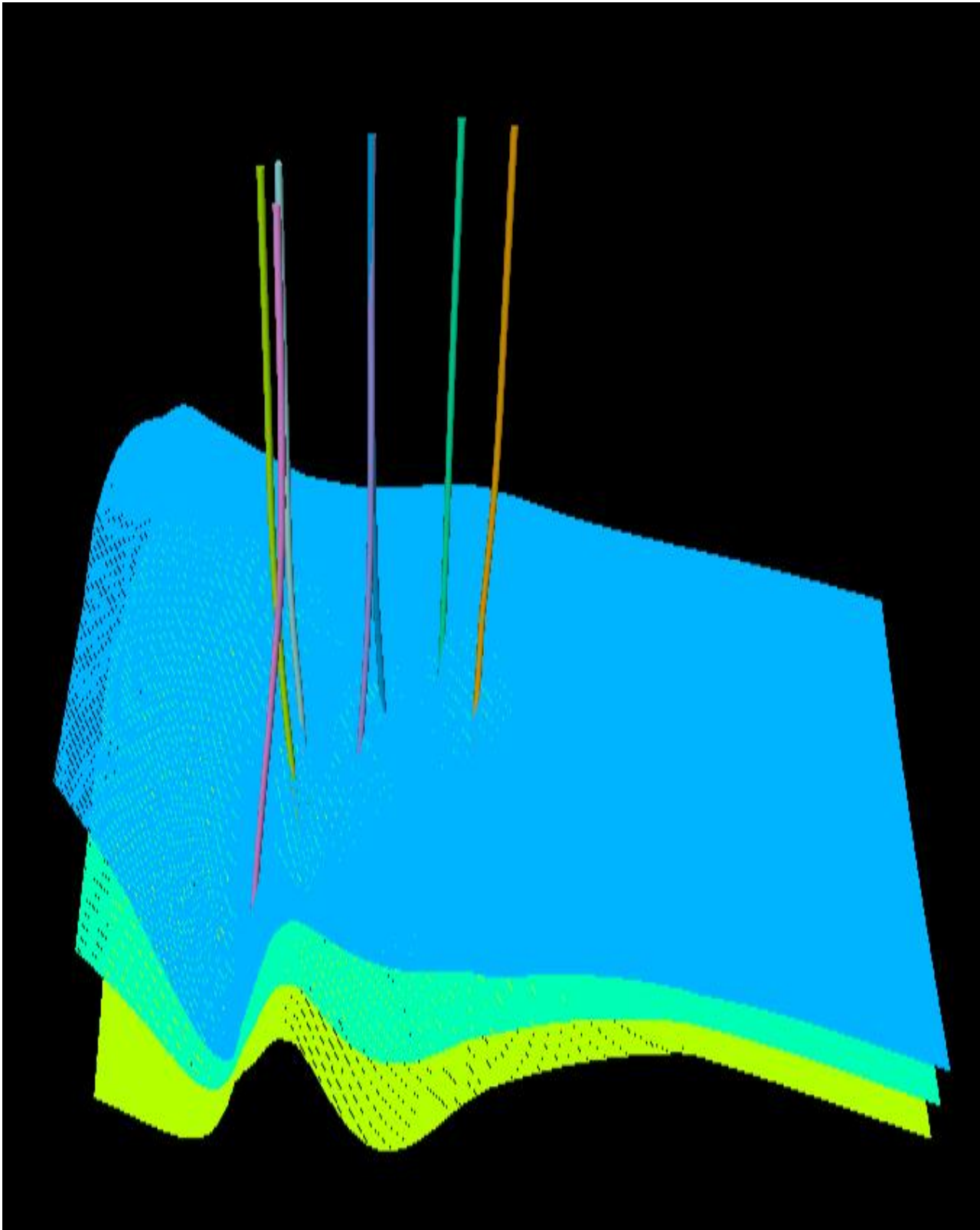
The horizon structural model of the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria for H7000 is predicated on figure 4.50 and figure 4.51.

Gridding

Gridding is the process of dividing a domain of interest (reservoir or gross rock volume) into blocks or grid cells.

Horizon Mapping

This structural model was created using a grid of 50x50 which favorably captures the reservoir heterogeneity. Horizon modeling was done to capture the structural and stratigraphic framework of the field in 3-dimension. This model helps in understanding the reservoir's structural & stratigraphic features.



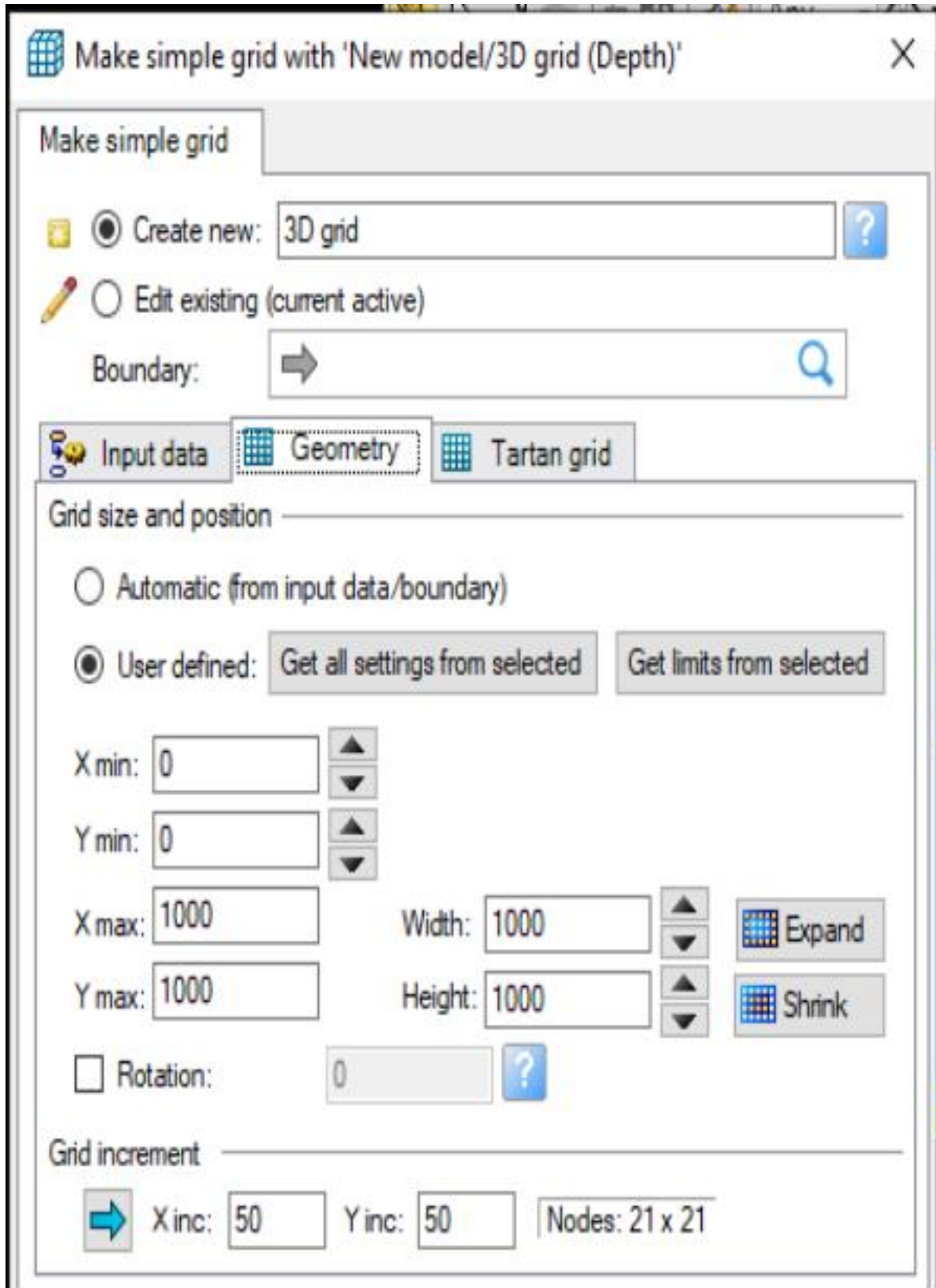


Figure 4.51: 3D Reservoir Gridding

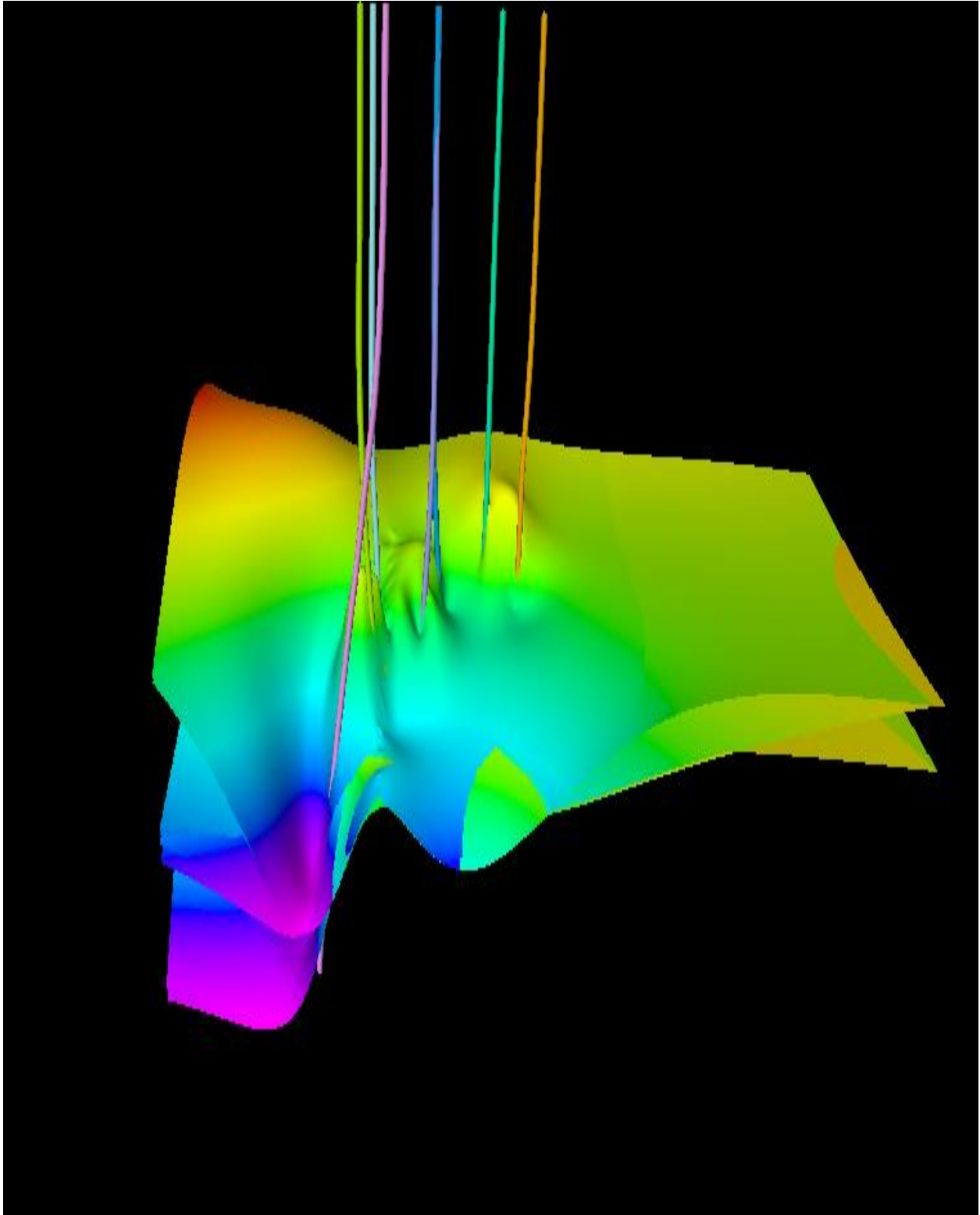


Figure 4.52: Horizon Modelling

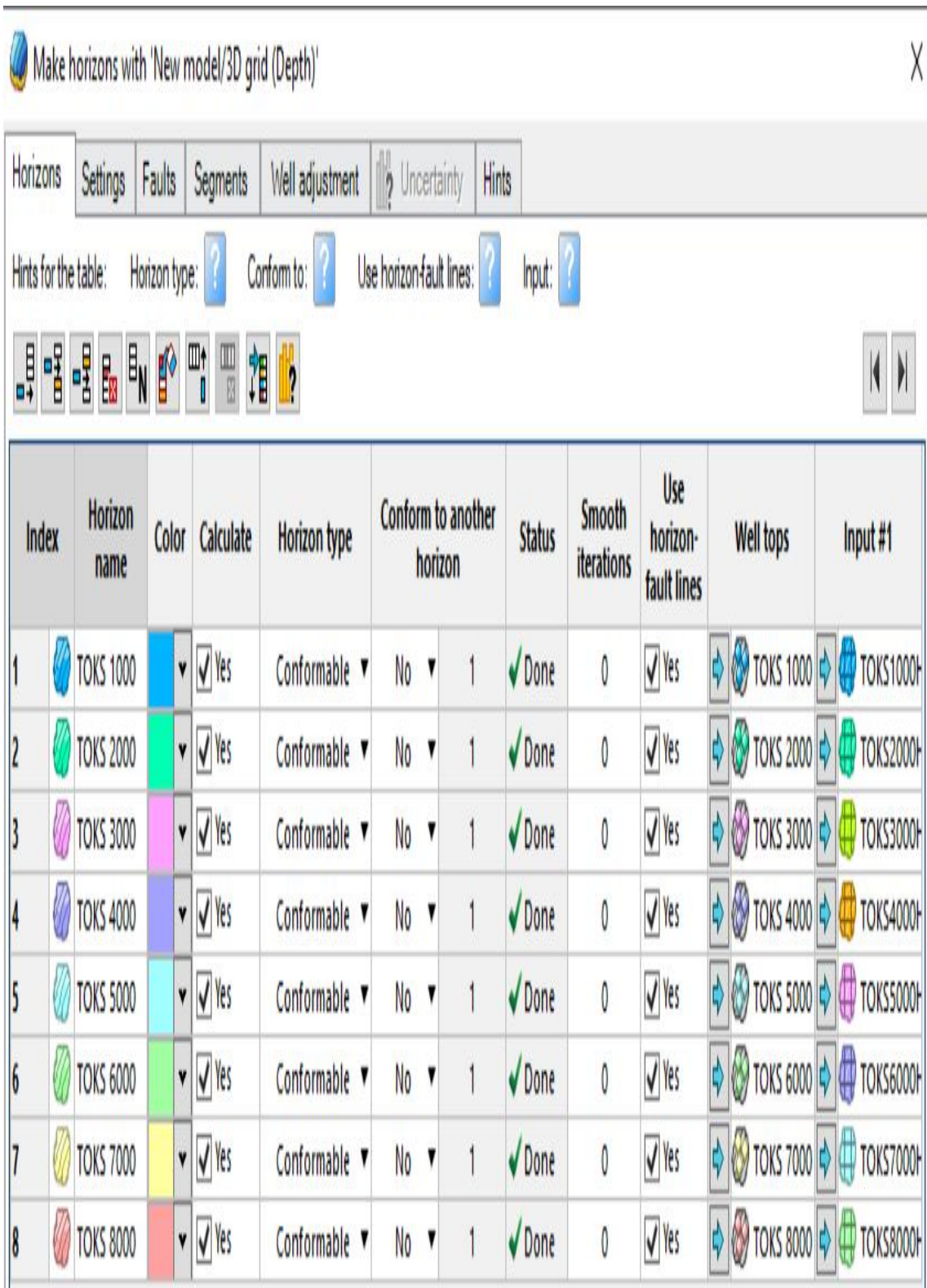


Figure 4.53: Structural Model of the Reservoirs – Horizons Modeling

Porosity Modelling

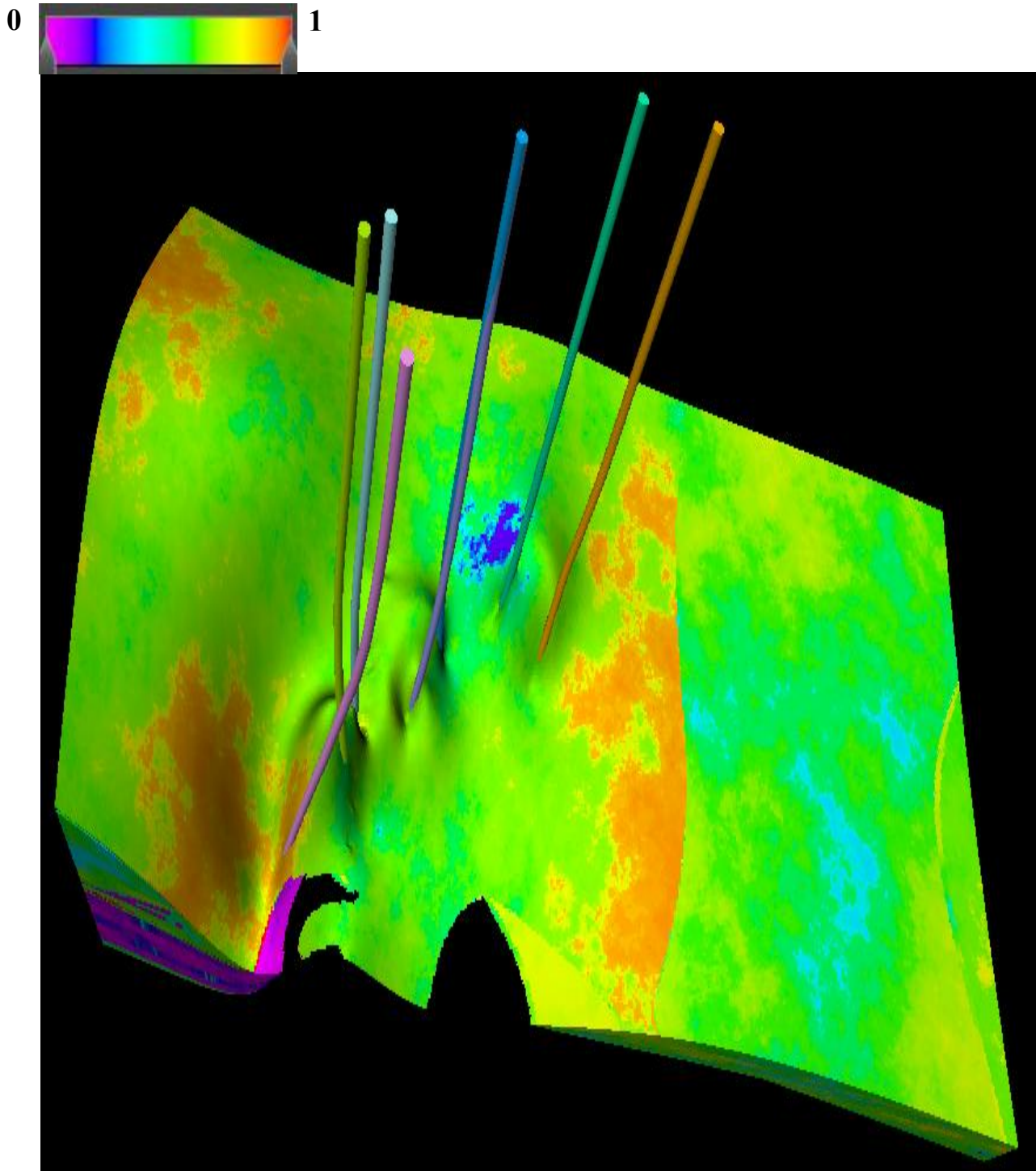


Figure 4.54: Porosity (TOKS 1000)

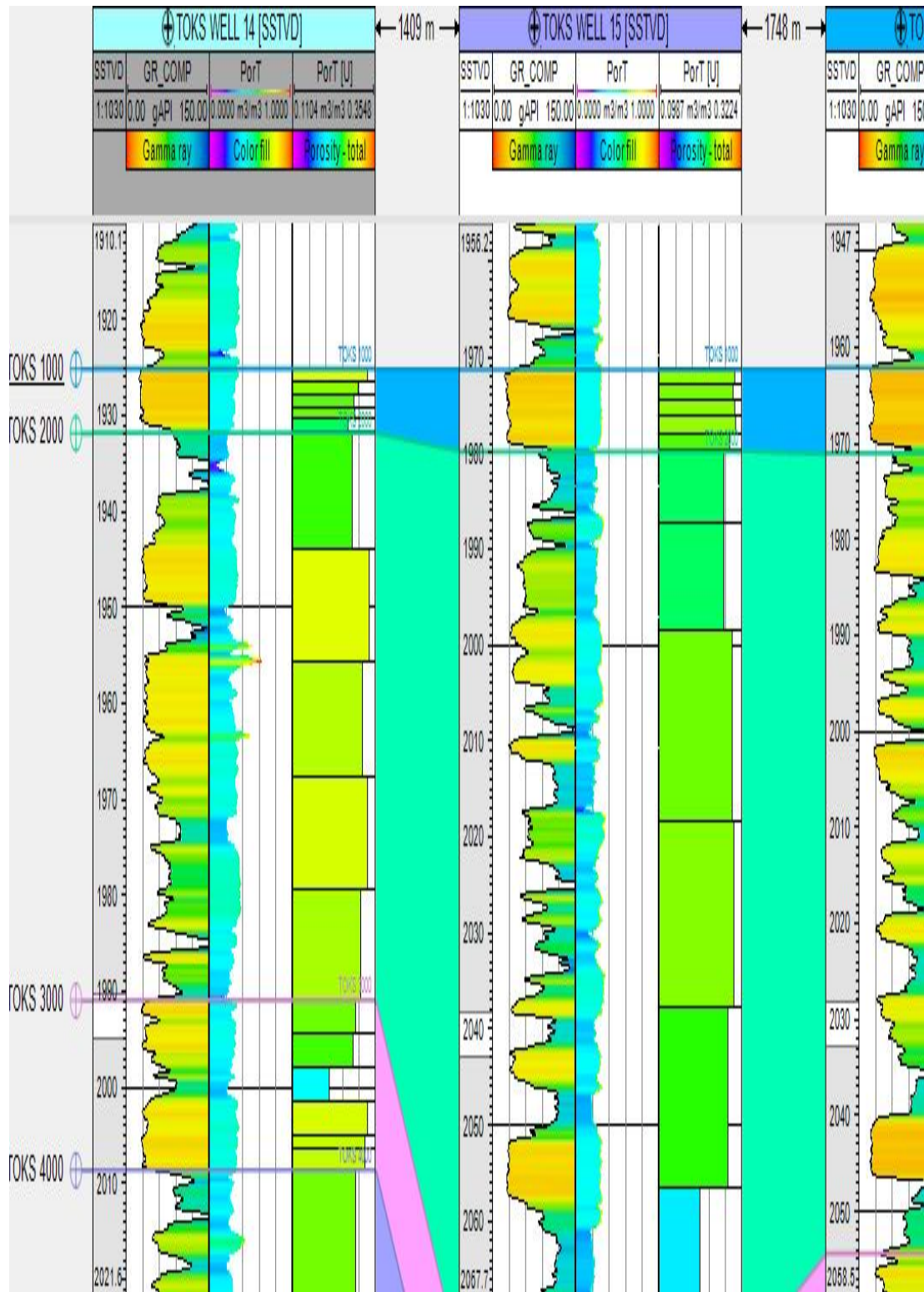
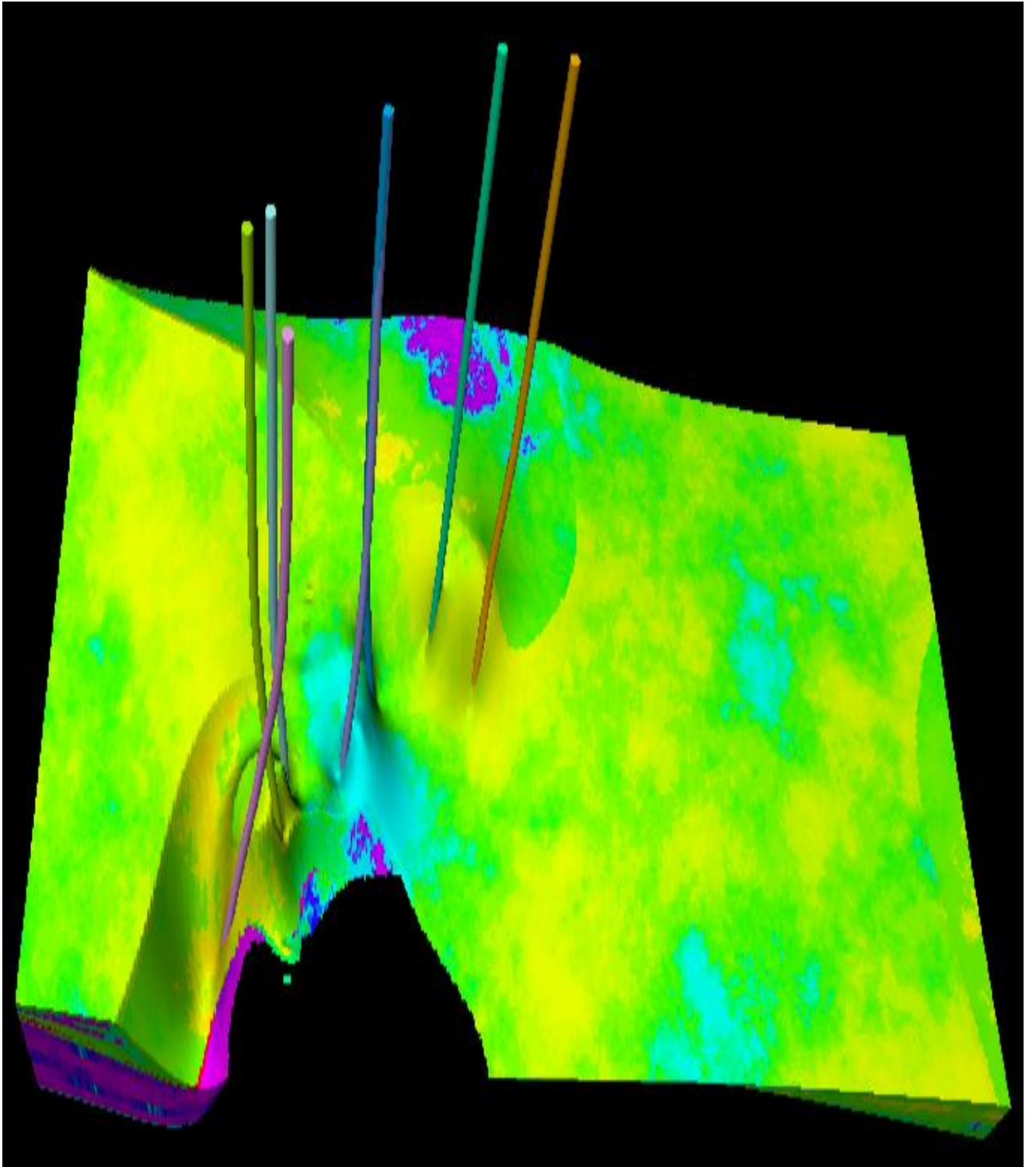


Figure 4.55: Petrophysical modeling – Porosity (TOKS 1000)



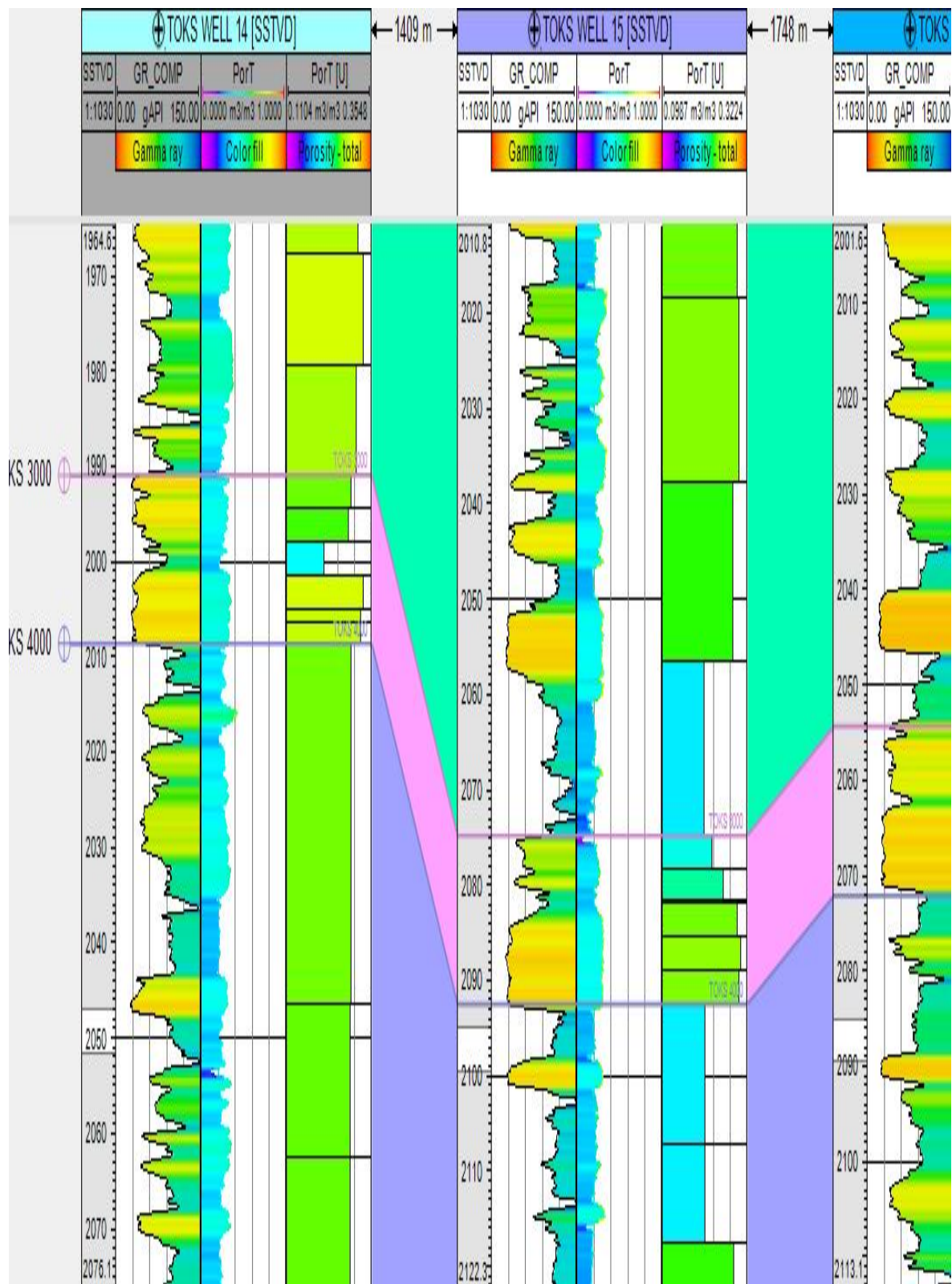


Figure 4.57: Petrophysical modeling – Porosity (TOKS 3000)

The porosity model used for the reservoirs in TOKS field was created biasing it to facies model using SGS algorithm (Stochastic Method) and was modeled using a defined variogram from data analysis. It provides a detail representation of porosity distribution within a reservoir volume. An understanding of this model is crucial for accurate estimation of reserve, production forecasting and optimization of recovery strategies.

The porosity value at the reservoir zones of the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria for TOKS 1000 ranges from 0.28 to 0.39. It is represented by figure 4.54 and figure 4.55. The porosity value at the reservoir zones of the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria for TOKS 3000 ranges from 0.25 to 0.36. It is represented by figure 4.56 and figure 4.57. The maps show the dominance of good to excellent porosity distribution of 0.3042 – 0.3857 within the area of TOKS 1000 and 0.2881 – 0.3491 within the area of TOKS 3000 in the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria biasing it to facies model using SGS algorithm (Stochastic Method). The obtained results is in consistence with the works of John and Oluwaseyi (2013), Ayenimelo (2016), Anyim (2010), Danwazan, *et al.*, (2023) and Adagunodo, *et al.*, (2022).

Porosity model provides a detail representation of porosity distribution within a reservoir volume. An understanding of this model is crucial for accurate estimation of reserve, production forecasting and optimization of recovery strategies. This indicates the pore spaces to accommodate fluid.

Water Saturation Model

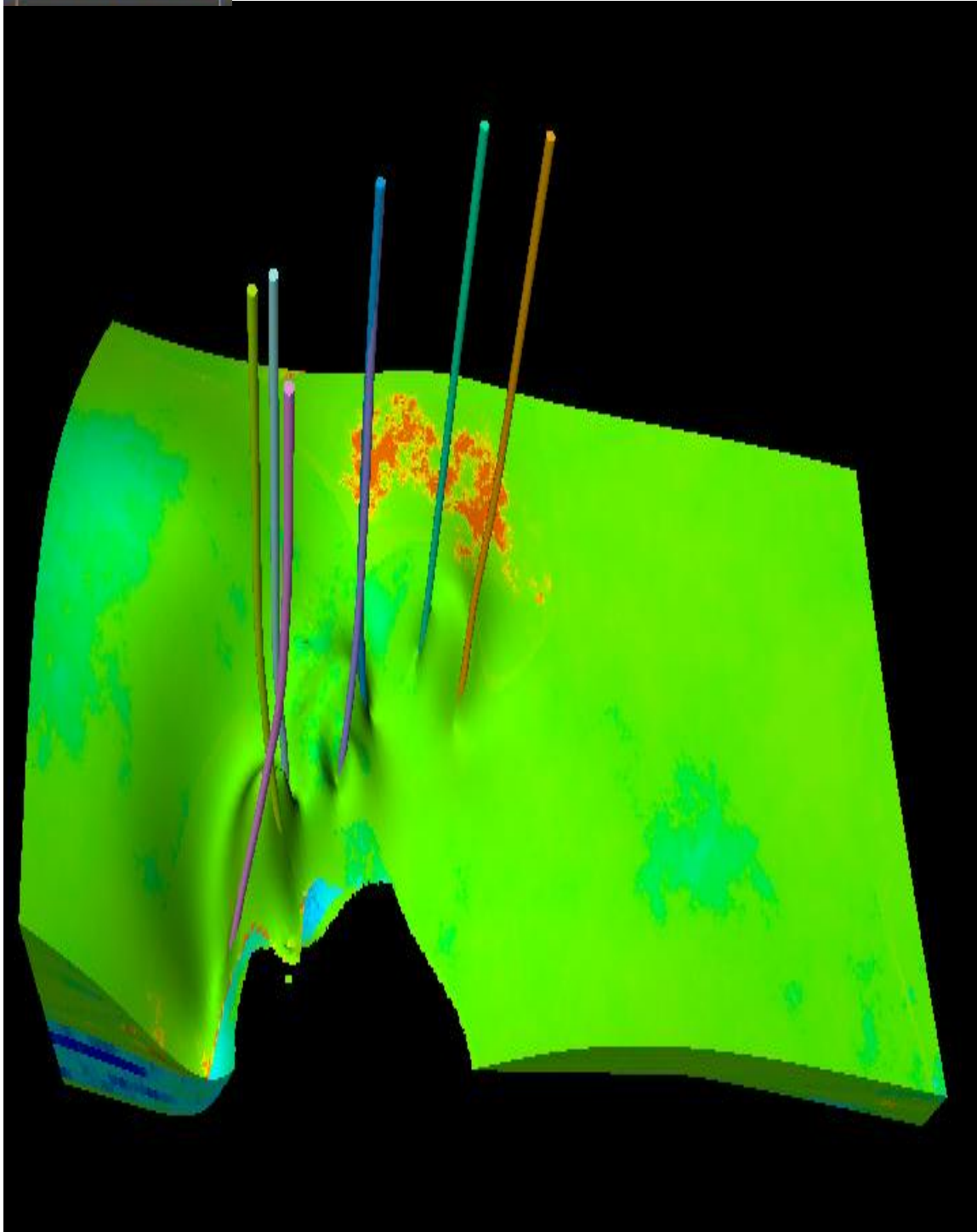


Figure 4.58: Petrophysical modeling – Water Saturation (TOKS 1000)

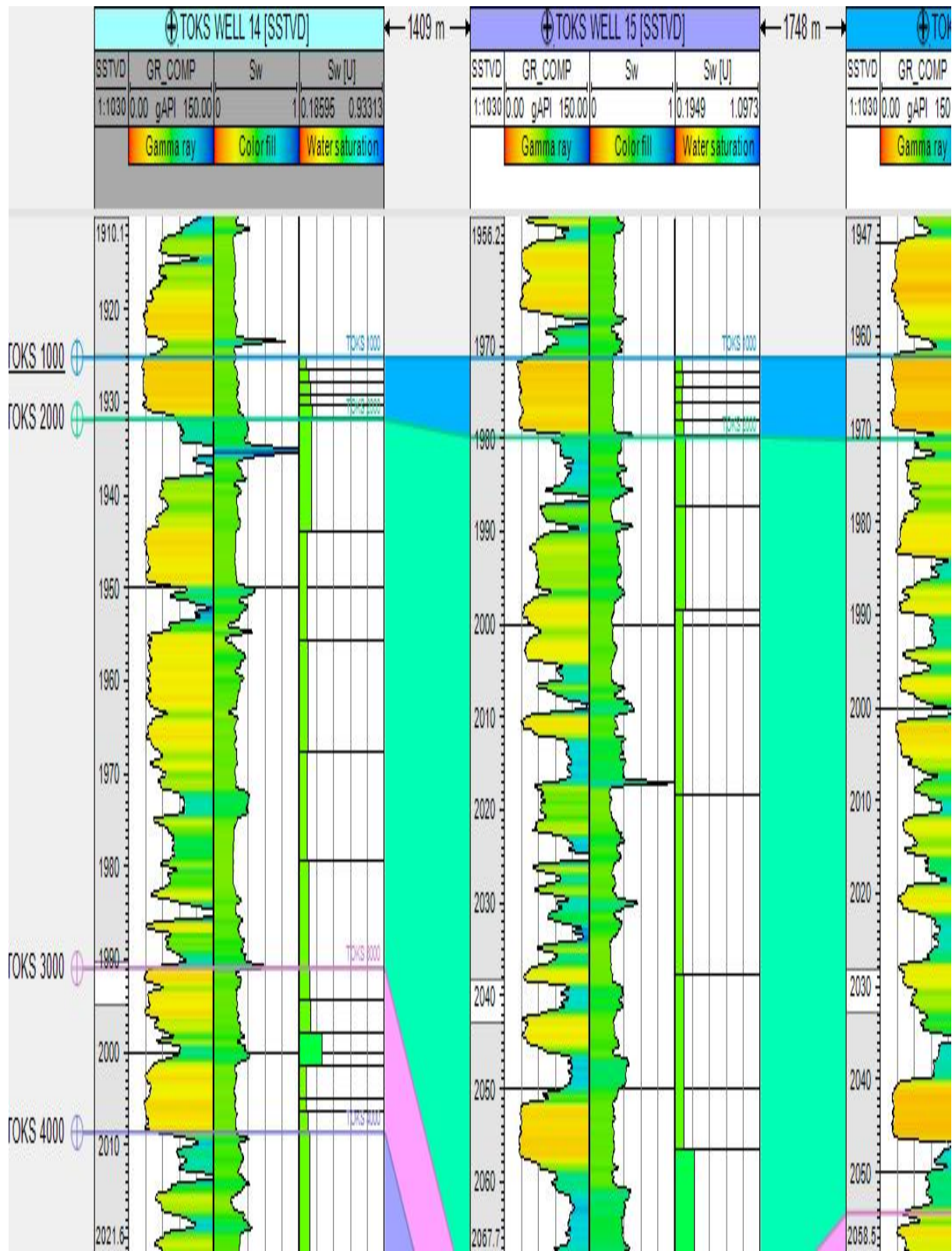


Figure 4.59: Petrophysical modeling – Water Saturation (TOKS 1000)

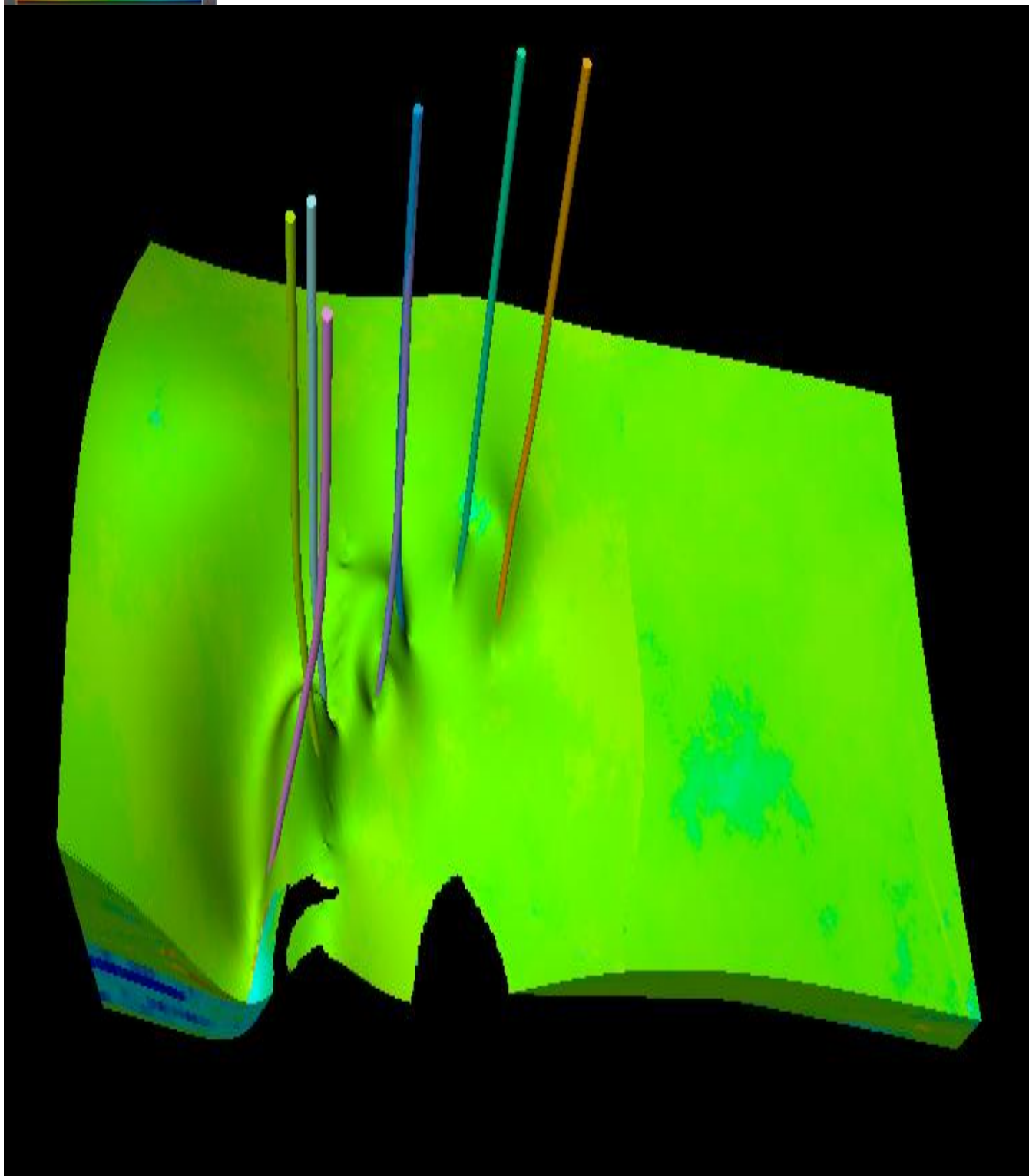


Figure 4.60: Petrophysical modeling – Water Saturation (TOKS 3000)

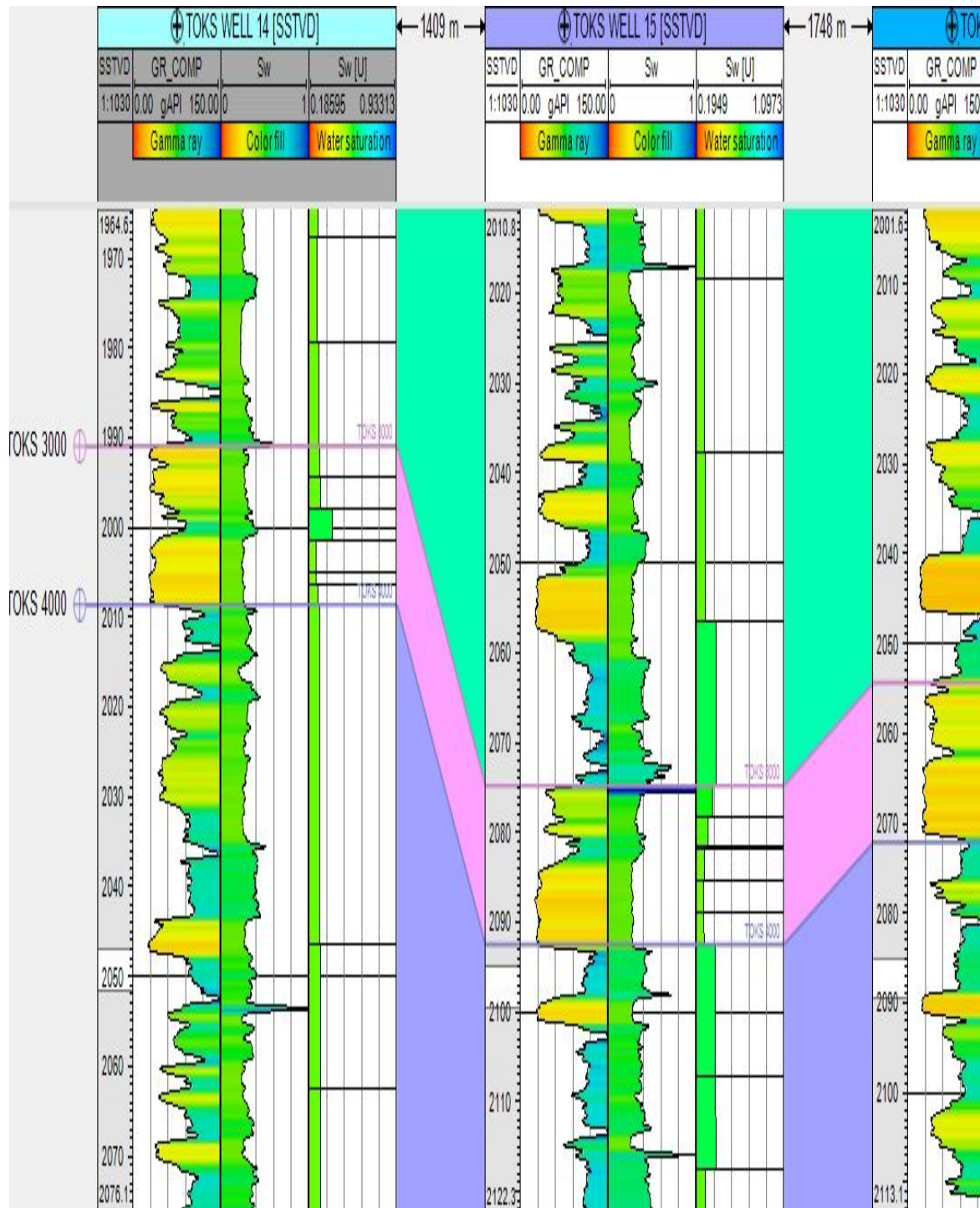


Figure 4.61: Petrophysical modeling – Water Saturation (TOKS 3000)

The map reveals that water saturation distribution within the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria area using SGS algorithm (Stochastic Method) at the reservoir zones ranges from 0.18 to 0.51 for TOKS 1000 (It is represented by figure 4.58 and figure 4.59).and TOKS 3000 (It is represented by figure 4.60 and figure 4.61).The S_w was modeled using a defined variogram from data analysis. Hydrocarbon reservoirs often contain multiple phases, including oil, gas, and water. The water saturation model helps characterize the distribution and movement of water within the reservoir rock. By understanding how water saturation varies spatially and temporally, we can better delineate the boundaries of hydrocarbon-bearing zones and estimate their volumes more accurately.

Net – To – Gross Modelling

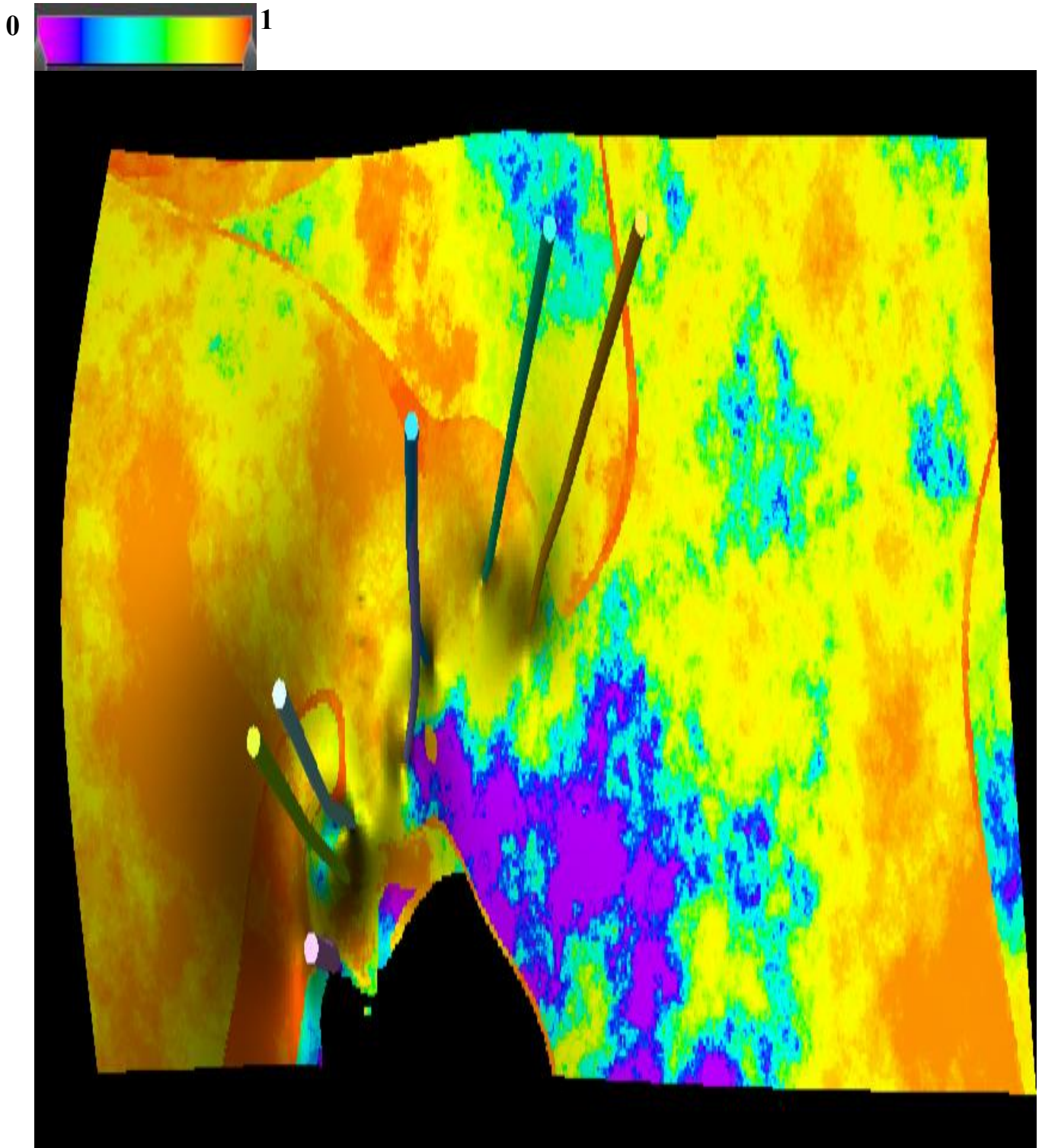


Figure 4.62: Petrophysical modeling – NTG (TOKS 1000)

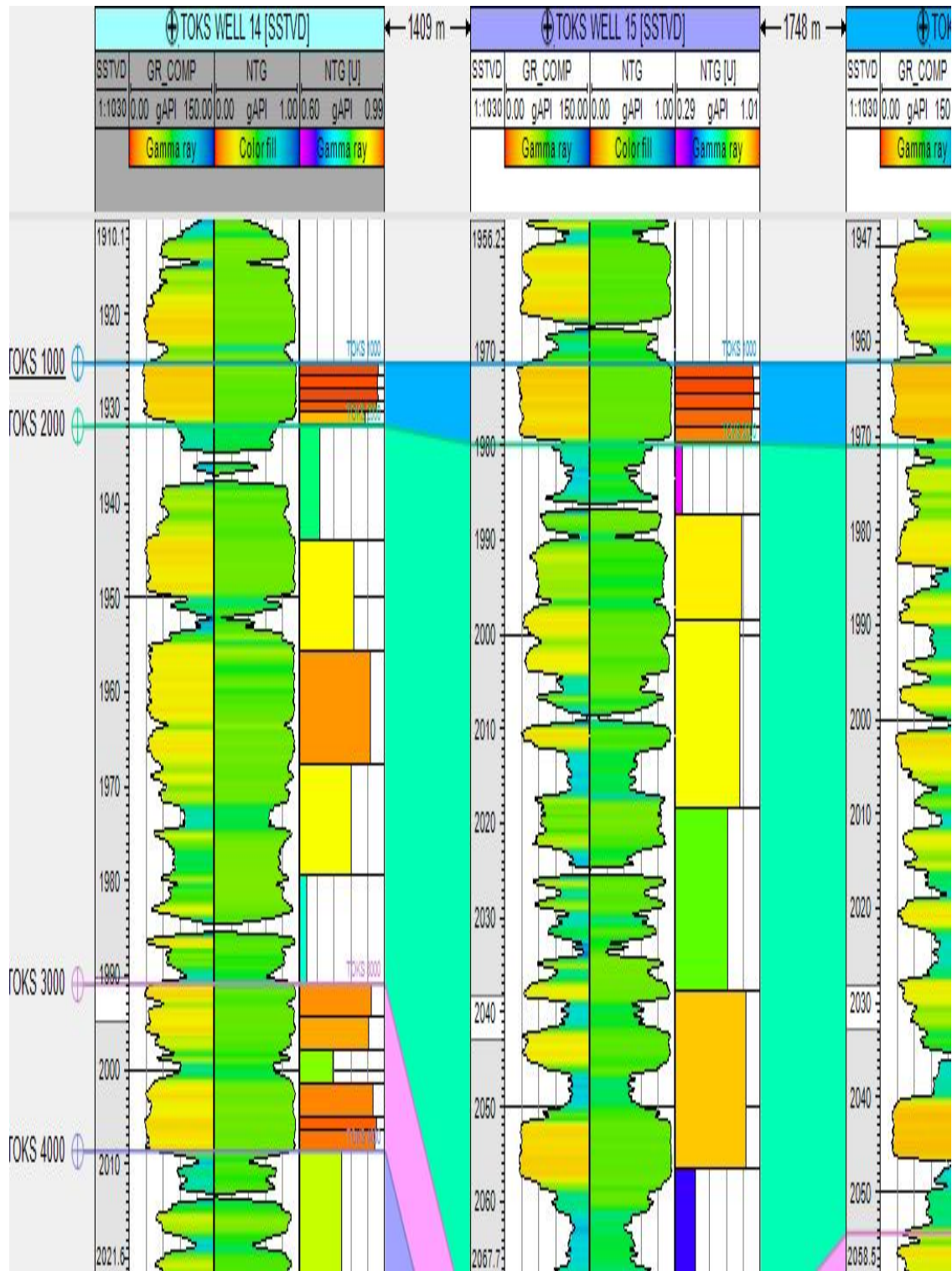


Figure 4.63: Petrophysical modeling – NTG (TOKS 1000)

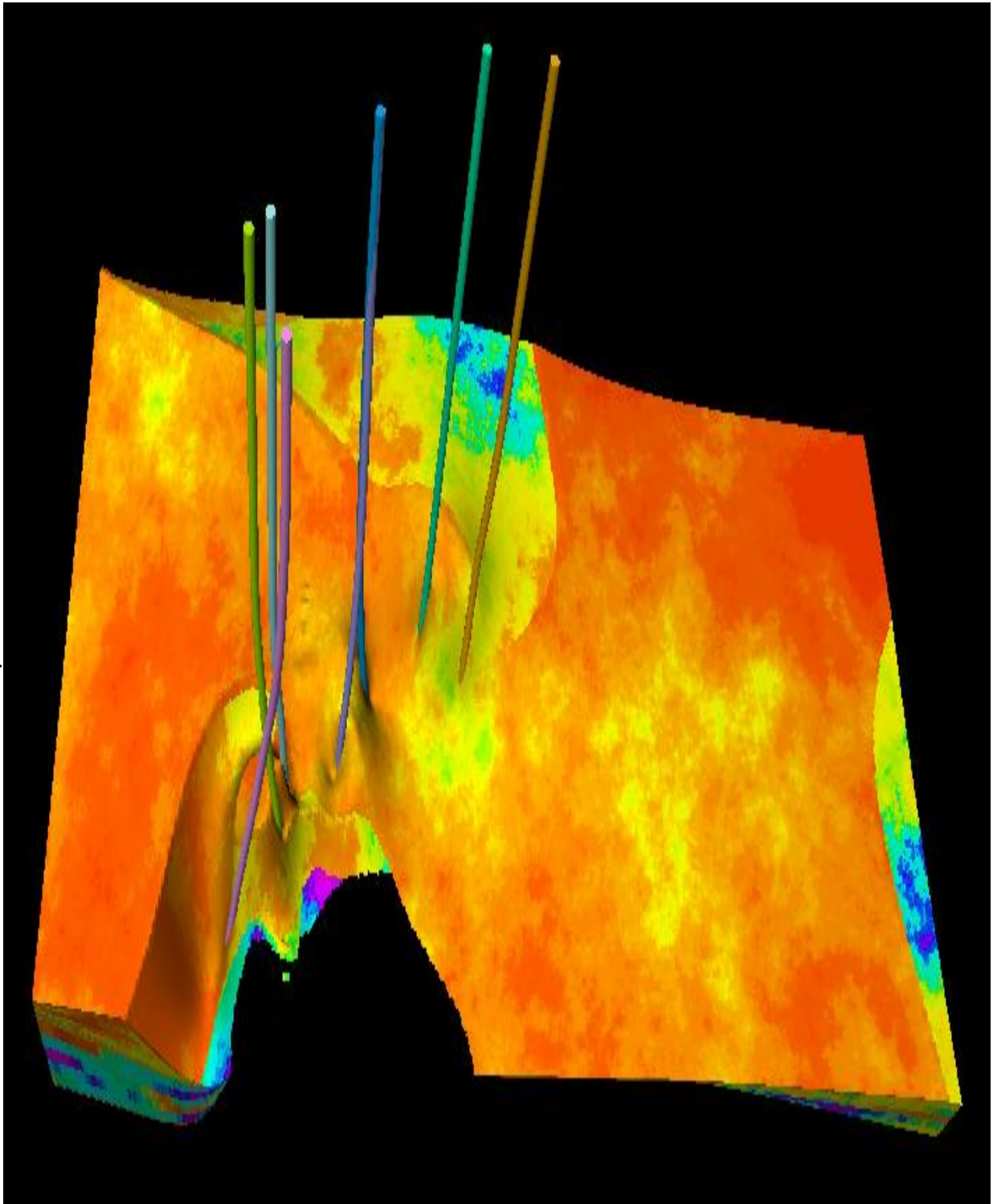


Fig.

Figure 4.64: Petrophysical modeling – NTG (TOKS 3000)

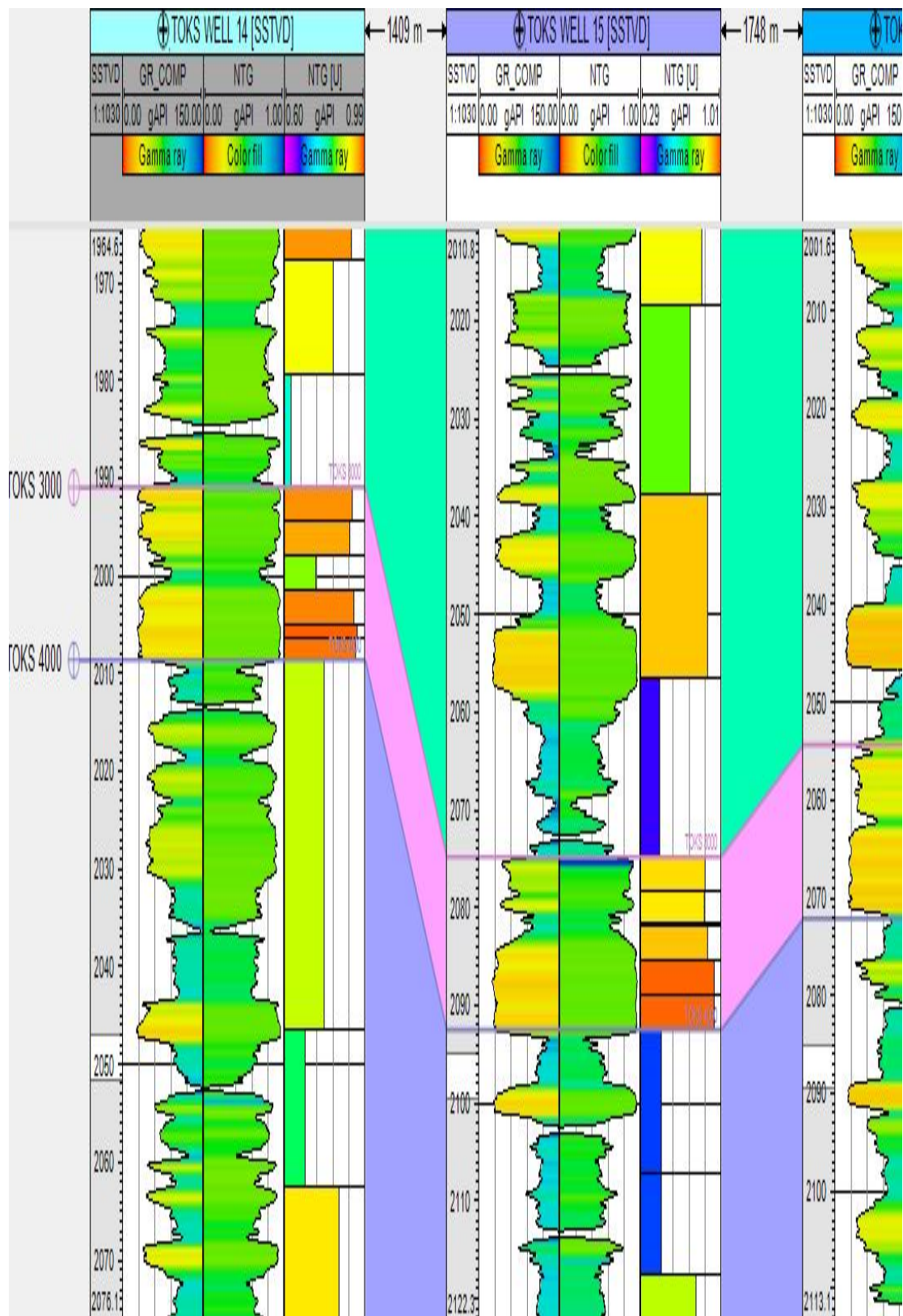


Figure 4.65: Petrophysical modeling – NTG (TOKS 3000)

The NTG model helps in characterizing the reservoir by providing information about the proportion of hydrocarbon-bearing rock (net) compared to non-hydrocarbon-bearing rock (gross). This characterization is essential for understanding the reservoir's geometry, connectivity, and potential productivity.

NTG model was created in the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria biasing it to facies model using SGS algorithm (Stochastic Method). The NTG was modeled using a defined variogram from data analysis. The NTG value at the reservoir zones ranges from 0.78 to 0.91 for TOKS 1000 (It is represented by figure 4.62 and figure 4.63). The NTG value at the reservoir zones ranges from 0.76 to 0.92 for TOKS 3000 (It is represented by figure 4.64 and figure 4.65). This is in consistence with the work of Danwazan (2023).

NTG model was created in the studied TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51 of the TOKS field, Niger Delta Basin, Nigeria biasing it to facies model using SGS algorithm (Stochastic Method). The NTG was modeled using a defined variogram from data analysis. The NTG value at the reservoir zones ranges from 0.78 to 0.91 for TOKS 3000. This is also in consistence with the work of Danwazan (2023) The obtained results is in consistence with the works of John and Oluwaseyi (2013), Ayenimelo (2016), Anyim (2010) and Adagunodo, *et al.*, (2022)..

Zonation of the Reservoirs

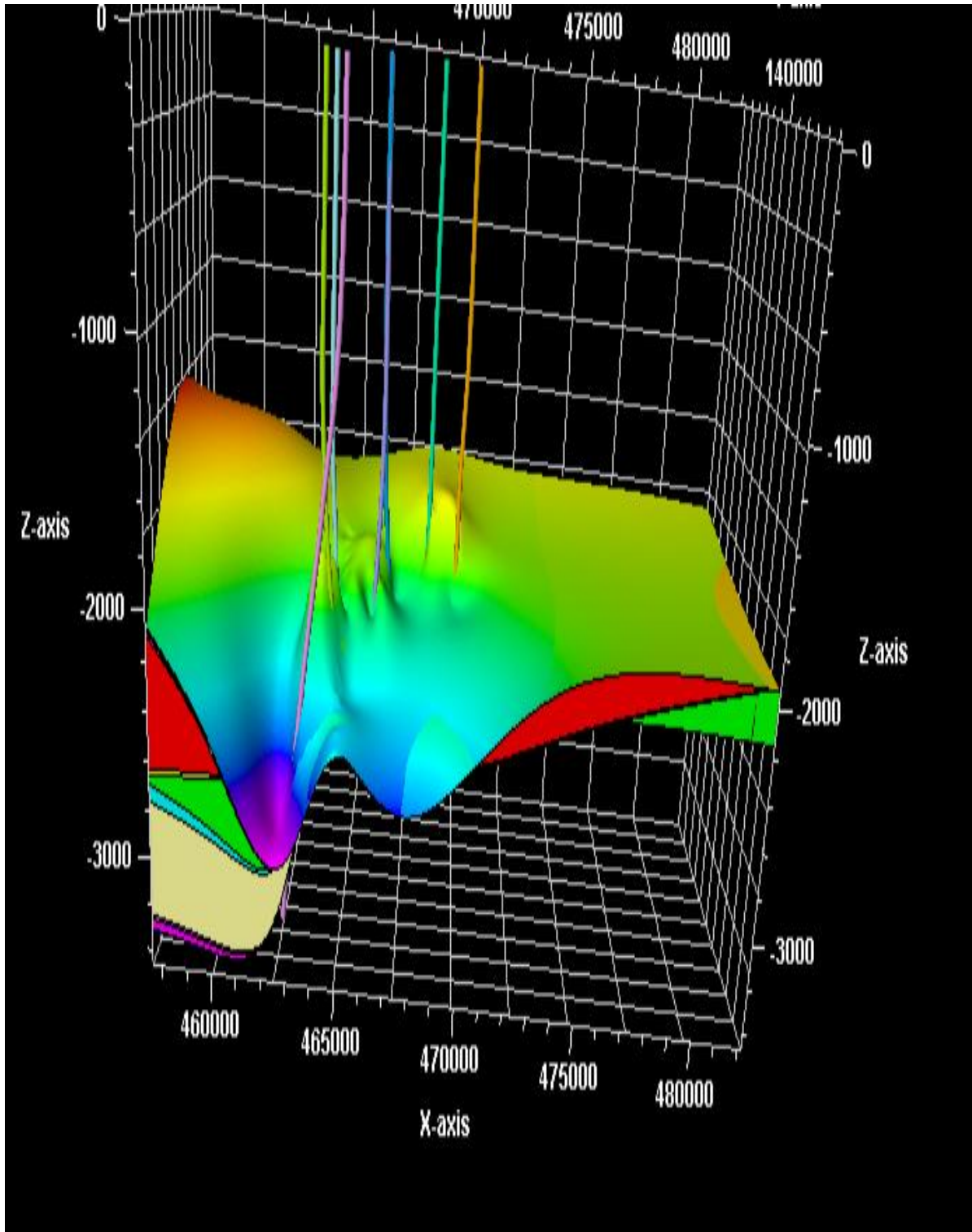


Figure 4.66: Petrophysical modeling – Zonation (TOKS Wells)

Make zones with 'New model/3D grid (Depth)'

Make zones

⚠ The calculation will be performed in the selected stratigraphic interval only.

Stratigraphic interval: TOKS 6000- TOKS 7000

Zones Settings Well adjustment Uncertainty

TOKS 6000 → TOKS 6000 (Well tops 3)

Name	Color	Input type	Input	Volume correct	Status
Thickness (Isochore	Thickness	<input checked="" type="checkbox"/> Yes	✓ Done
TOKS 7000			TOKS 7000		✓ Done
Thickness (Isochore	Thickness	<input checked="" type="checkbox"/> Yes	✓ Done
Horizon					📄 New
Zone		Isochore		<input checked="" type="checkbox"/> Yes	📄 New
Horizon					📄 New
Zone		Isochore		<input checked="" type="checkbox"/> Yes	📄 New
Horizon					📄 New
Zone		Isochore		<input checked="" type="checkbox"/> Yes	📄 New
Horizon					📄 New
Zone		Isochore		<input checked="" type="checkbox"/> Yes	📄 New

Figure 4.67: Zonation of the Reservoirs

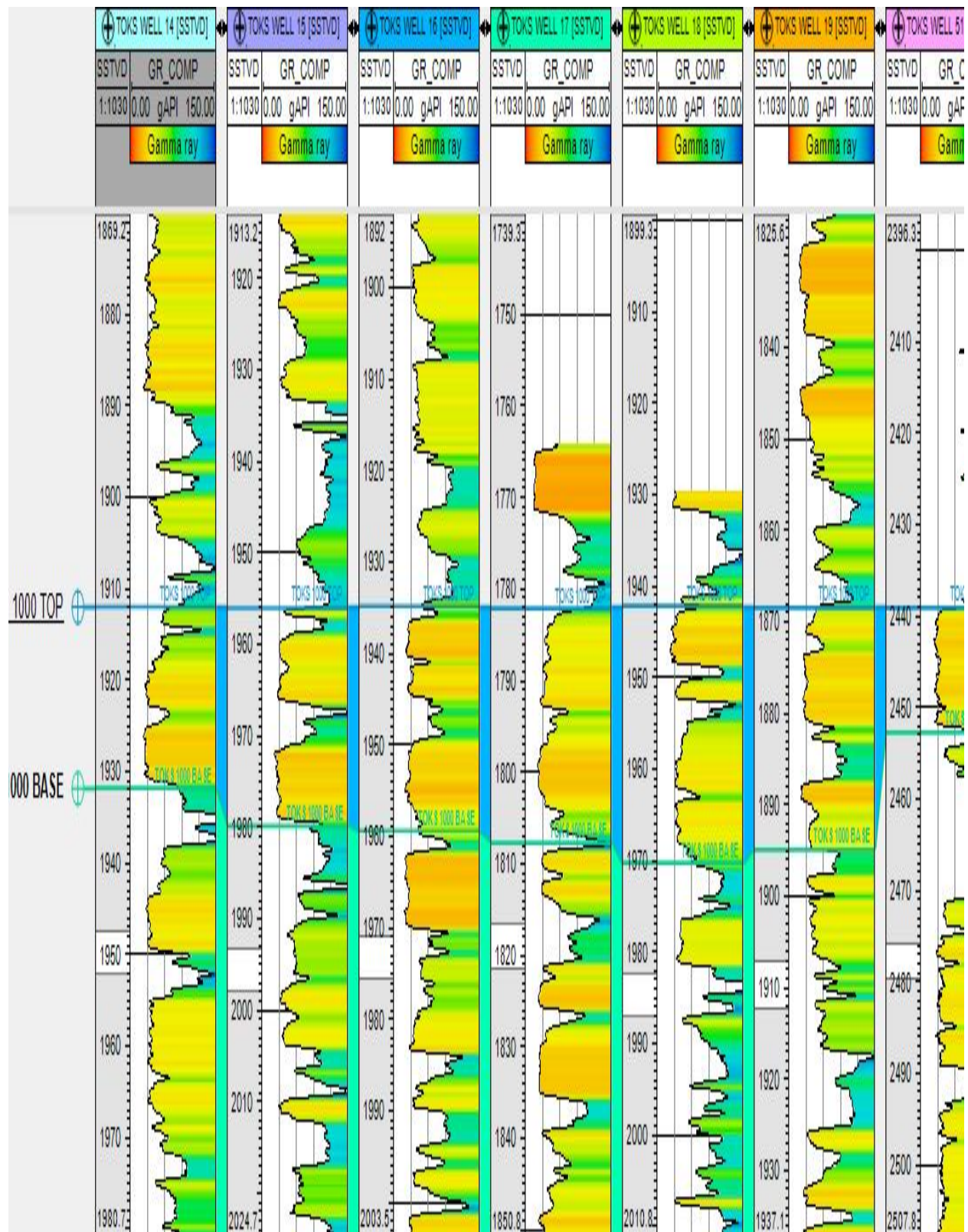


Figure 4.68: TOKS 1000 Reservoir Zones

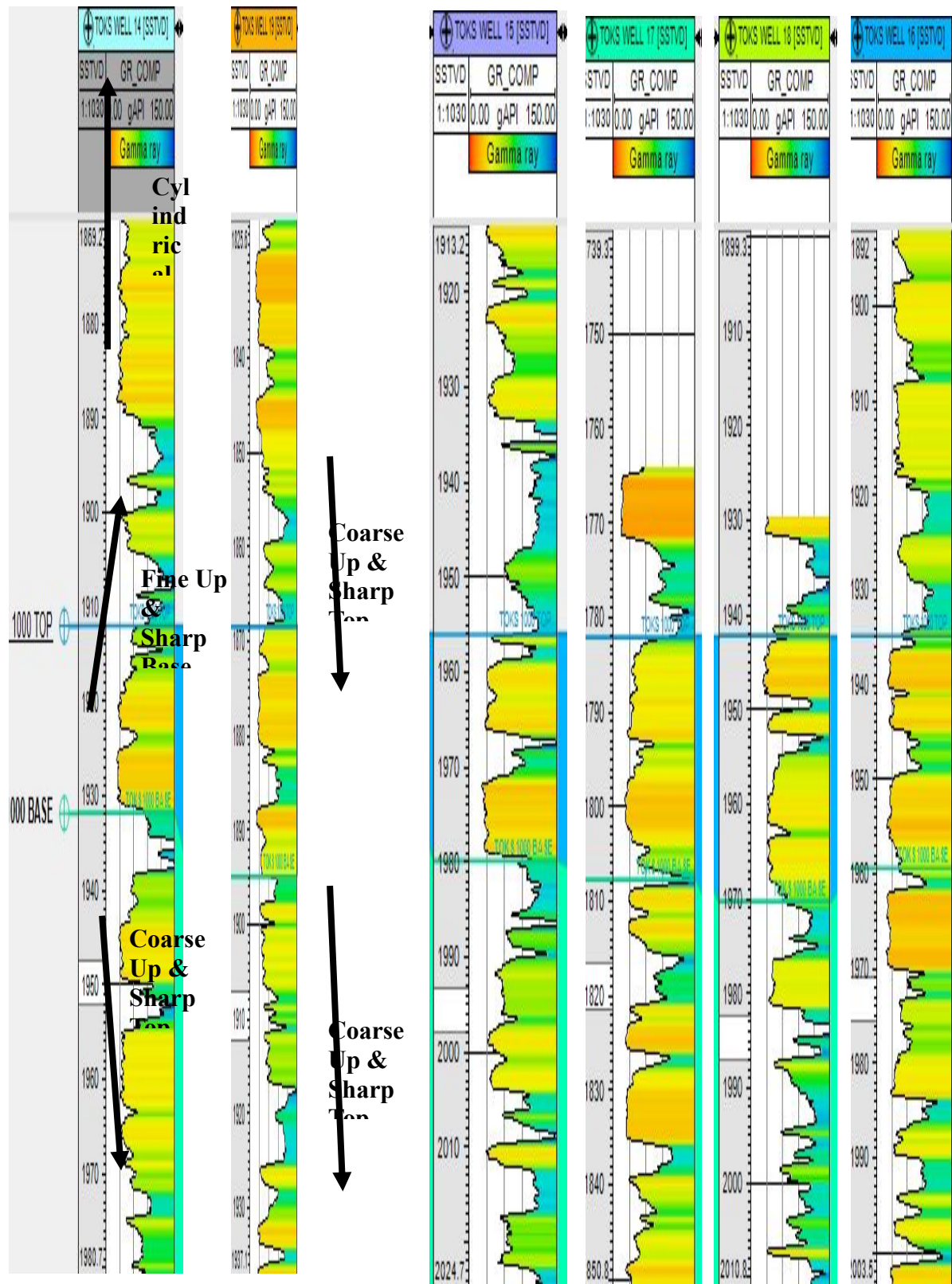


Figure 4.69: TOKS 1000 RESERVOIR ZONES

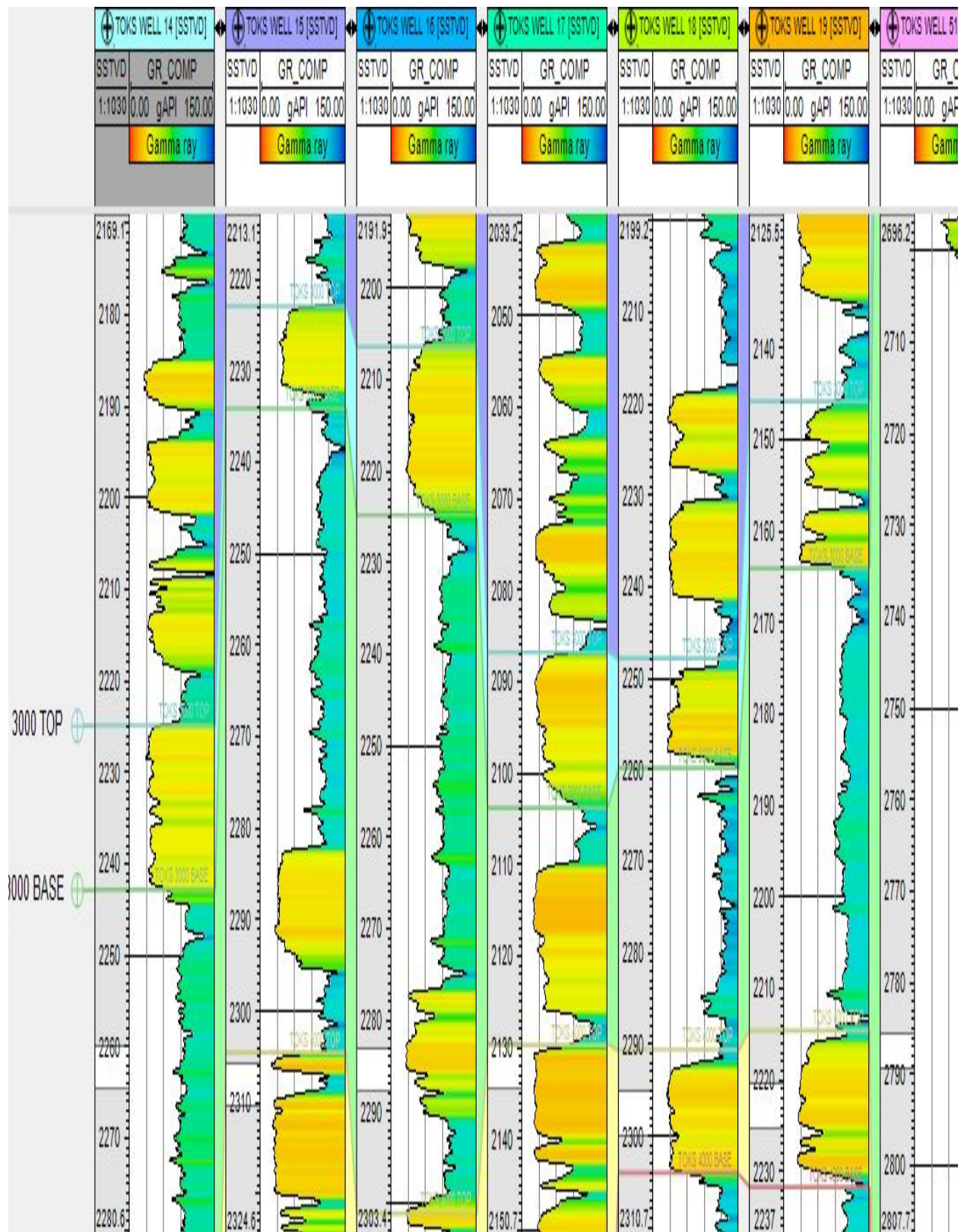


Figure 4.70: TOKS 3000 Reservoir Zones

Geological zonation involves dividing the reservoir into distinct zones based on lithology, sedimentary facies, or stratigraphic units.

In the Niger Delta Basin of Nigeria, reservoir zonation based on lithology and sedimentary facies involves the identification of different zones within a reservoir that exhibit distinct characteristics. These zones are defined by the types of rocks and the depositional environments that existed when the reservoirs were formed.

The studied reservoir intervals in studied wells (TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51) for both TOKS 1000 and TOKS 3000 in TOKS Field, Niger Delta Basin shows that the GR log motif depicts serrated models. From the integrated data set, The GR log motifs show the lithology characteristics are alternating sequences of sandstone and shale. The prominent sequence in the wells comprises the reservoir rocks with intercalation of sand and shale bodies depicting that logging begins and ends in the Agbada Formation of the Niger Delta Basin of Nigeria. This stratigraphic sequence is a common feature of the Agbada Formation in the Niger Delta, where these sandstone serves as reservoirs in the TOKS field. These reservoirs are the productive zone based on the log motif and Gamma ray log signatures.

In all the studied wells (TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51) for both TOKS 1000 and TOKS 3000 in the TOKS Field, Niger Delta Basin sandstones and shales are the only lithologies encountered and the sedimentary facies encountered are sandstones and shale facies. The delineated zones in the TOKS Field is composed of high porosity and high permeability. Also, using the well log signatures, areas showing low GR reading values were easily identified as possible hydrocarbon

reservoirs. Similar signatures were correlated as representing the continuity of the unit or formation and this is in consistence with the work of Anyim (2010).

Layering of the Reservoirs Zones

In a well within the Niger Delta Basin in Southern Nigeria, reservoir zones are typically layered within the three (3) main stratigraphic units, this are Akata, Agbada and Benin Formation. Agabada Formation is particularly important for hydrocarbon reservoirs containing sandstones and shales with varying amounts of porosity and permeability. They contain the primary oil and gas – bearing sands with reservoirs often characterized by stacked barrier bar and point-bar sandstones.

When we applied zonation, the interface are all geological. When we do simulation these kind of very thick layers are not accurate enough. We have to insert more geometrical layers in between. That is, make the grid finer. And that is called layering.

A number of layers was created for the reservoirs in-order to capture heterogeneity.

Layering is not geological. It is a geometric thing.

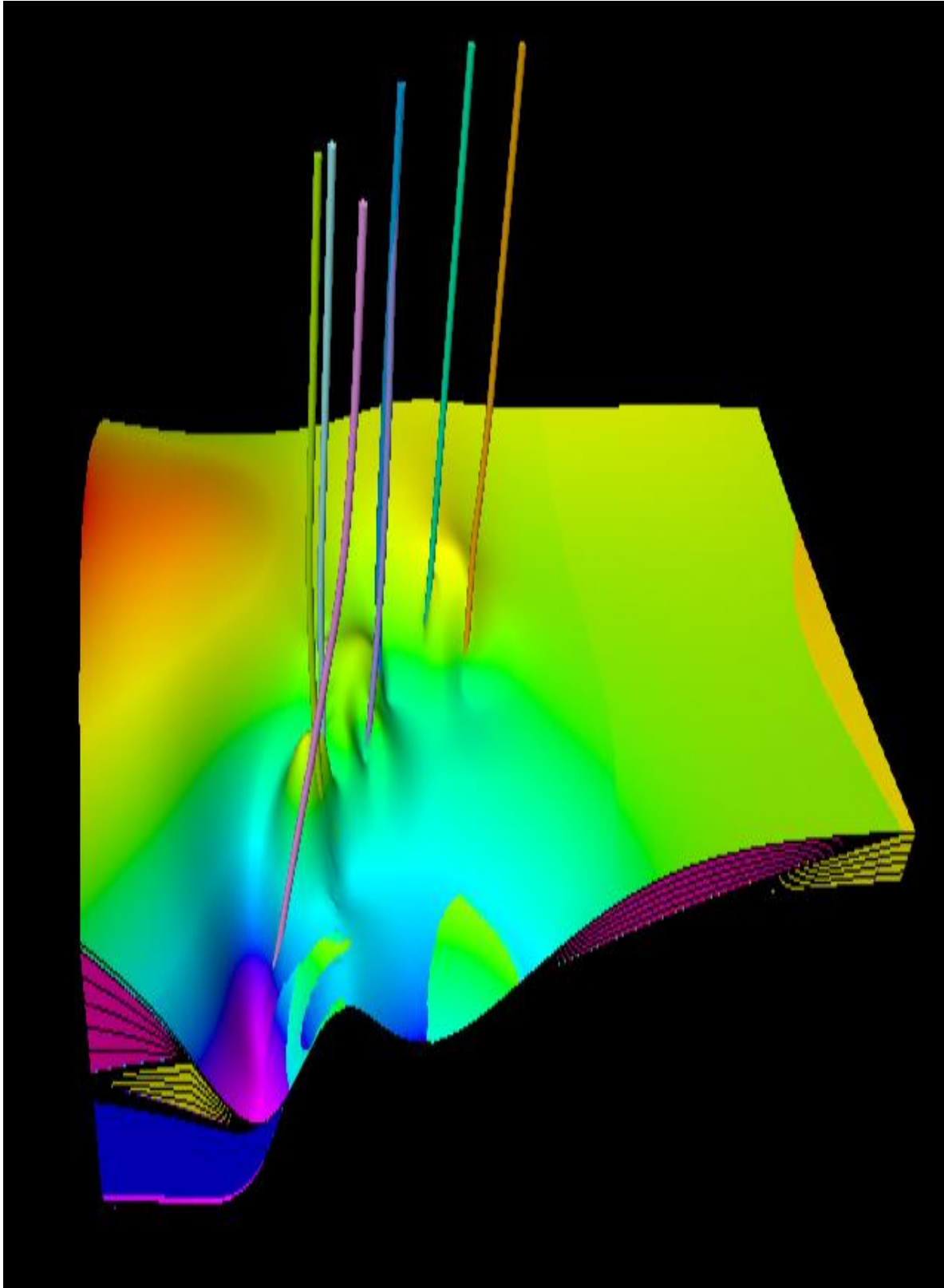


Figure 4.71: Layering of Reservoir Zones

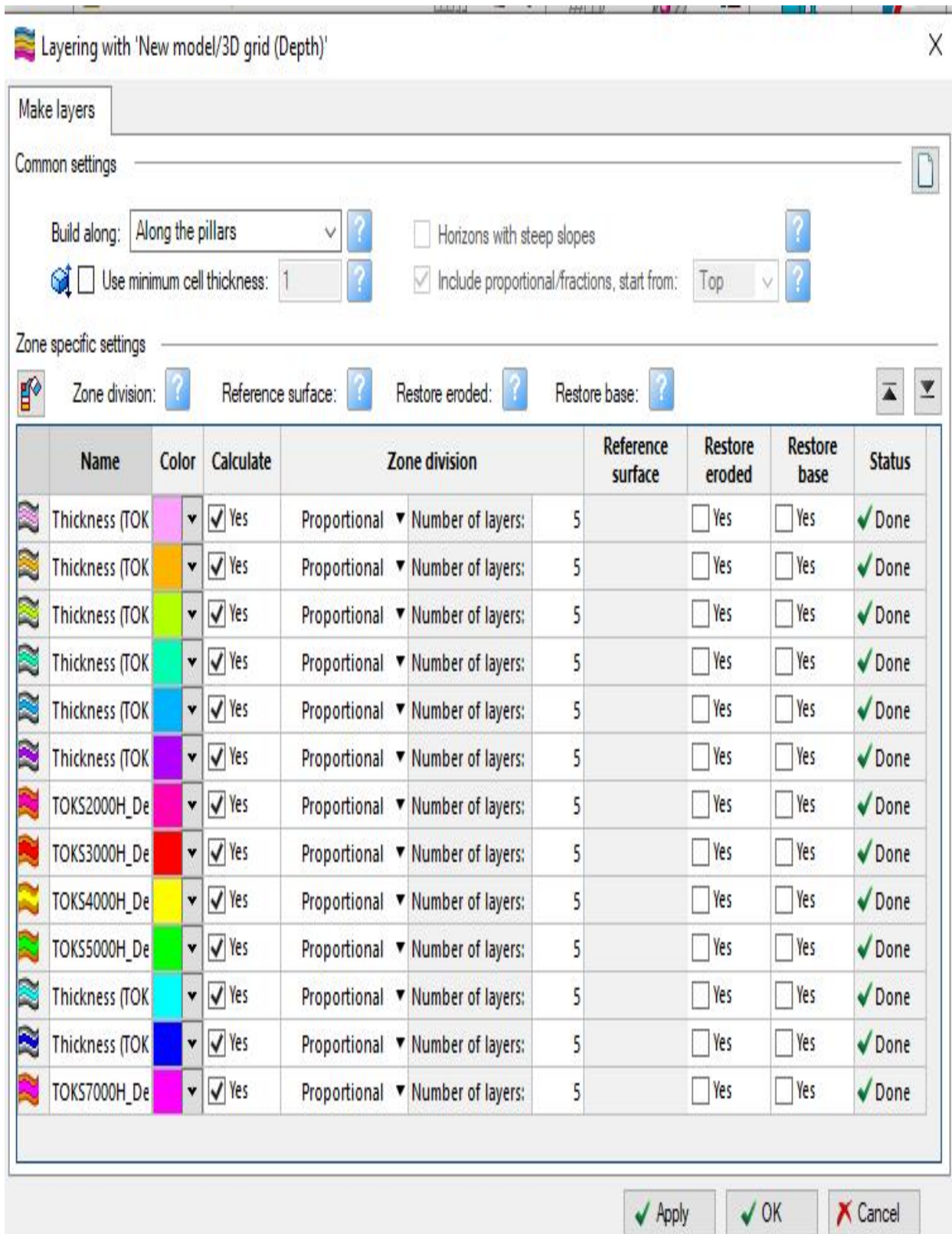


Figure 4.72: Layering of the Reservoirs Zones

Upscaling the Reservoir Properties

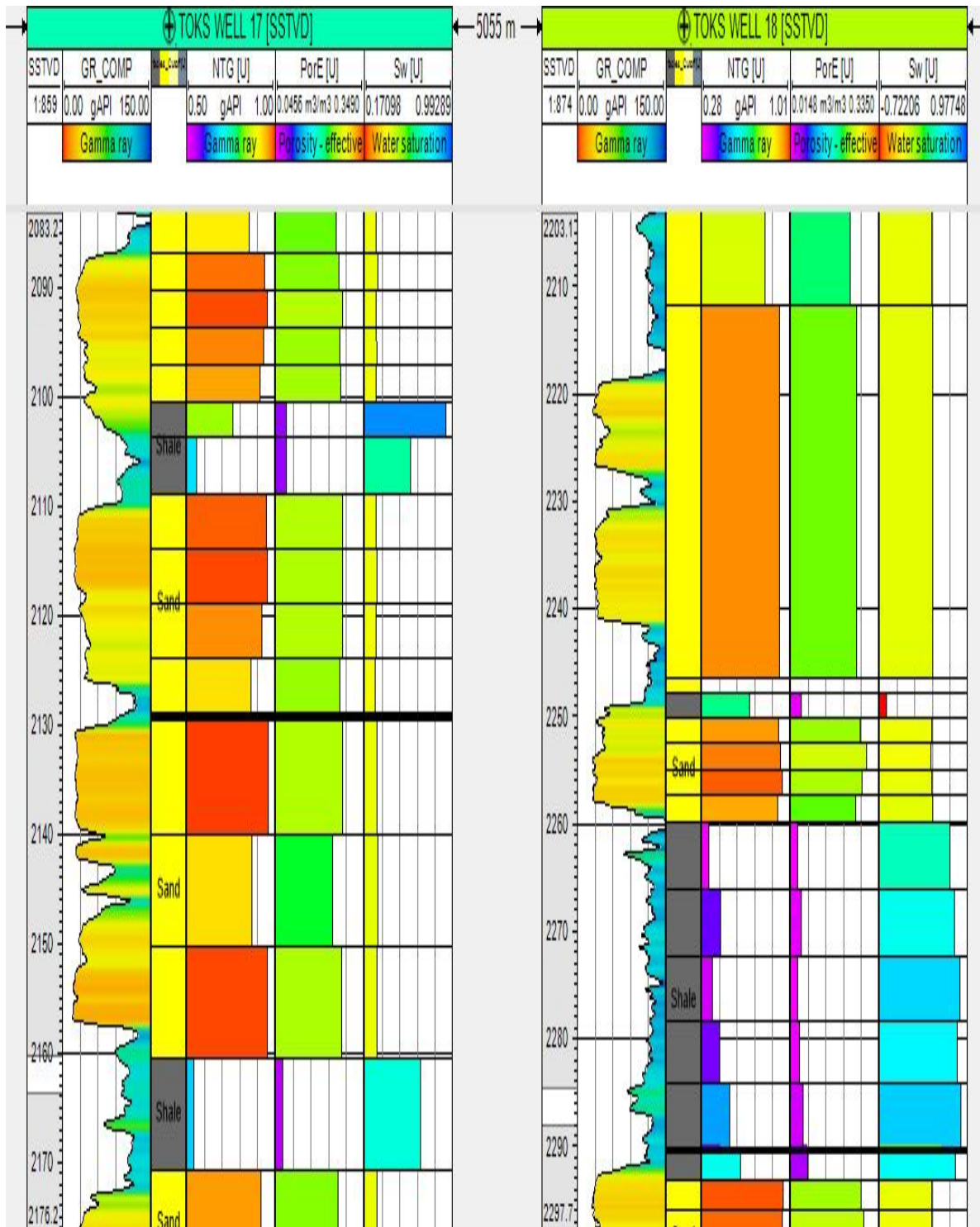


Figure 4.73: Upscaling the Reservoir Properties

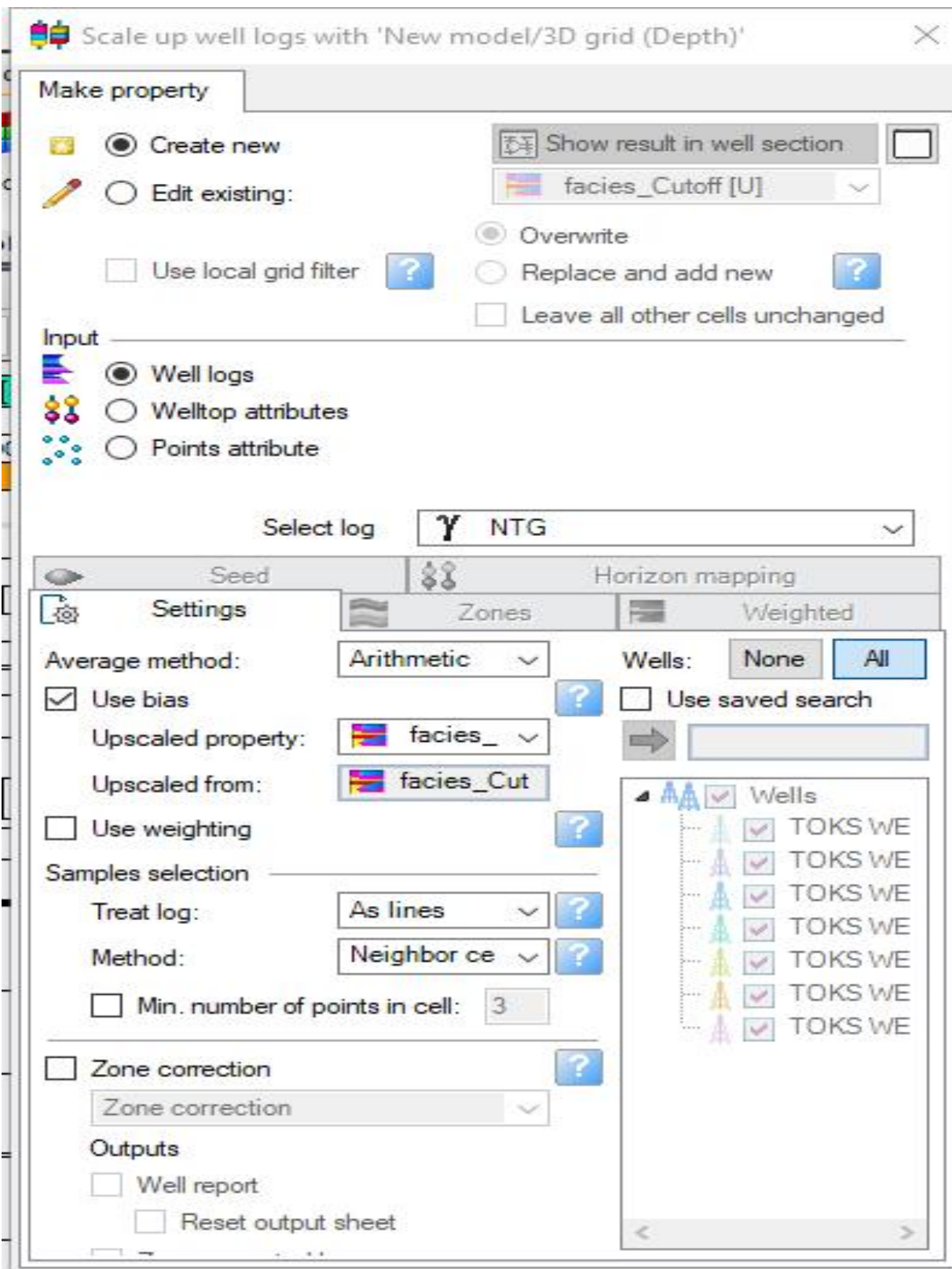


Figure 4.74: Upscaling the Reservoir Properties

Upscaling: In some cases, the resolution of the data collected may be higher than that required for reservoir simulation. Therefore, upscaling techniques are used to aggregate the fine-scale geological and reservoir properties into larger grid blocks that are suitable for use in reservoir simulation models.

Facies Modeling

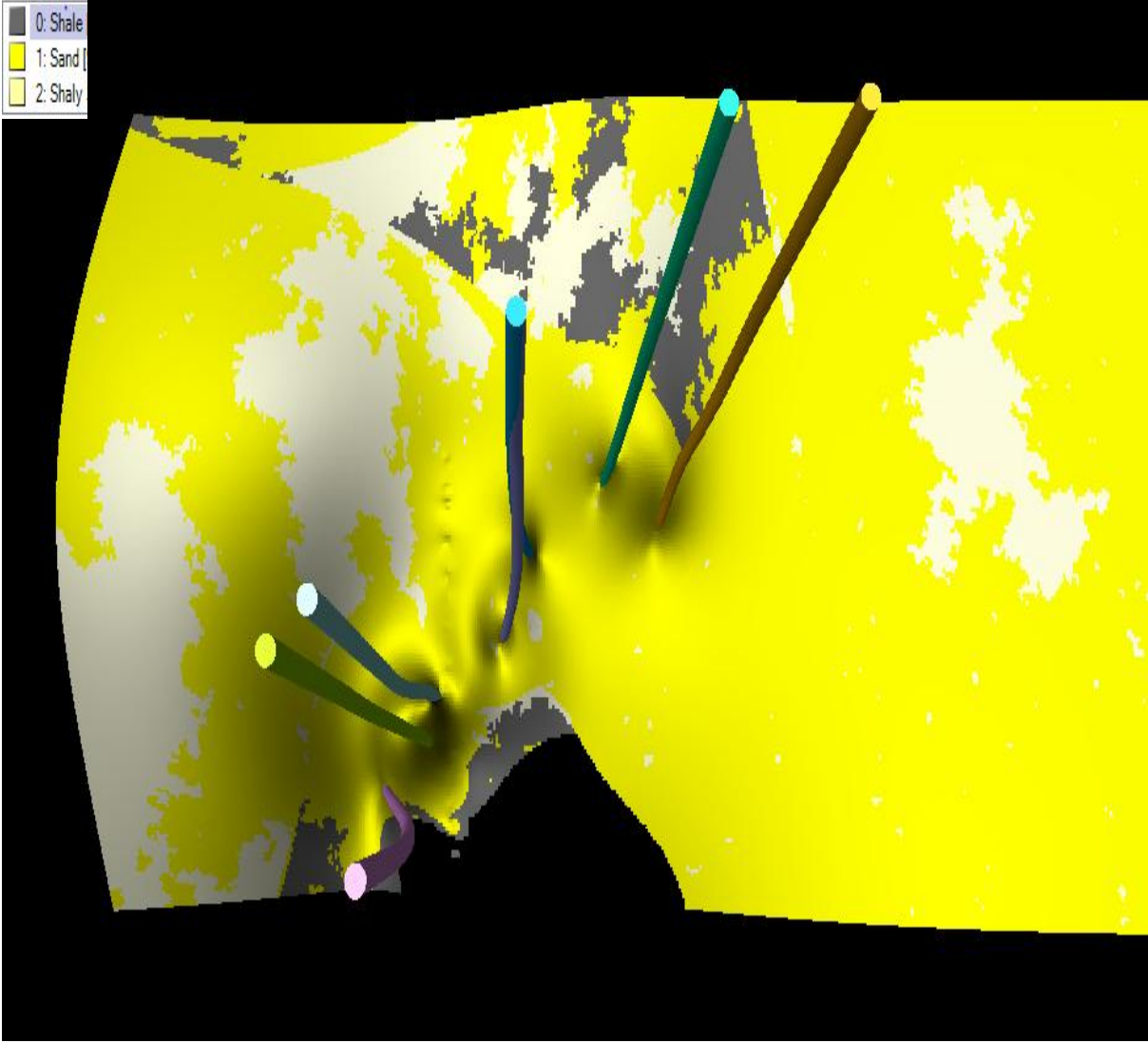


Figure. 4.75: Facies Model (TOKS 1000)

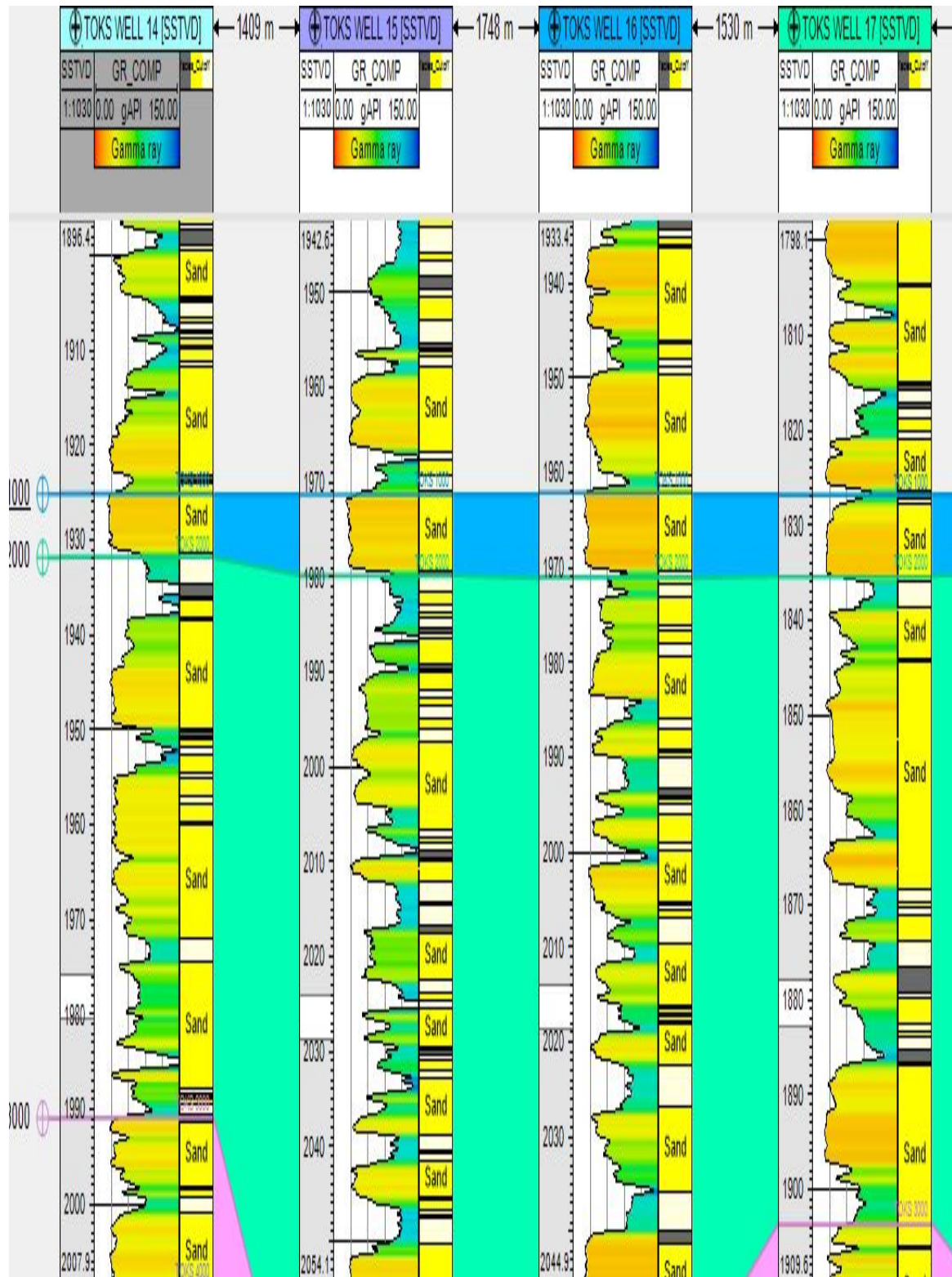


Figure 4.76: Facies Model (TOKS 1000)

Facies Model (TOKS 1000)

Reservoir Facial Modeling is a technique used in reservoir characterization to represent the heterogeneity and spatial distribution of different rock types or facies within a reservoir.

It involves dividing the reservoir into distinct facies based on their sedimentological characteristics, such as grain size, sorting, mineralogy, or sedimentary structures.

Facies model was created using sequential indicator simulation (SIS) algorithm

Facies types considered are Sand, coarse sand and shale

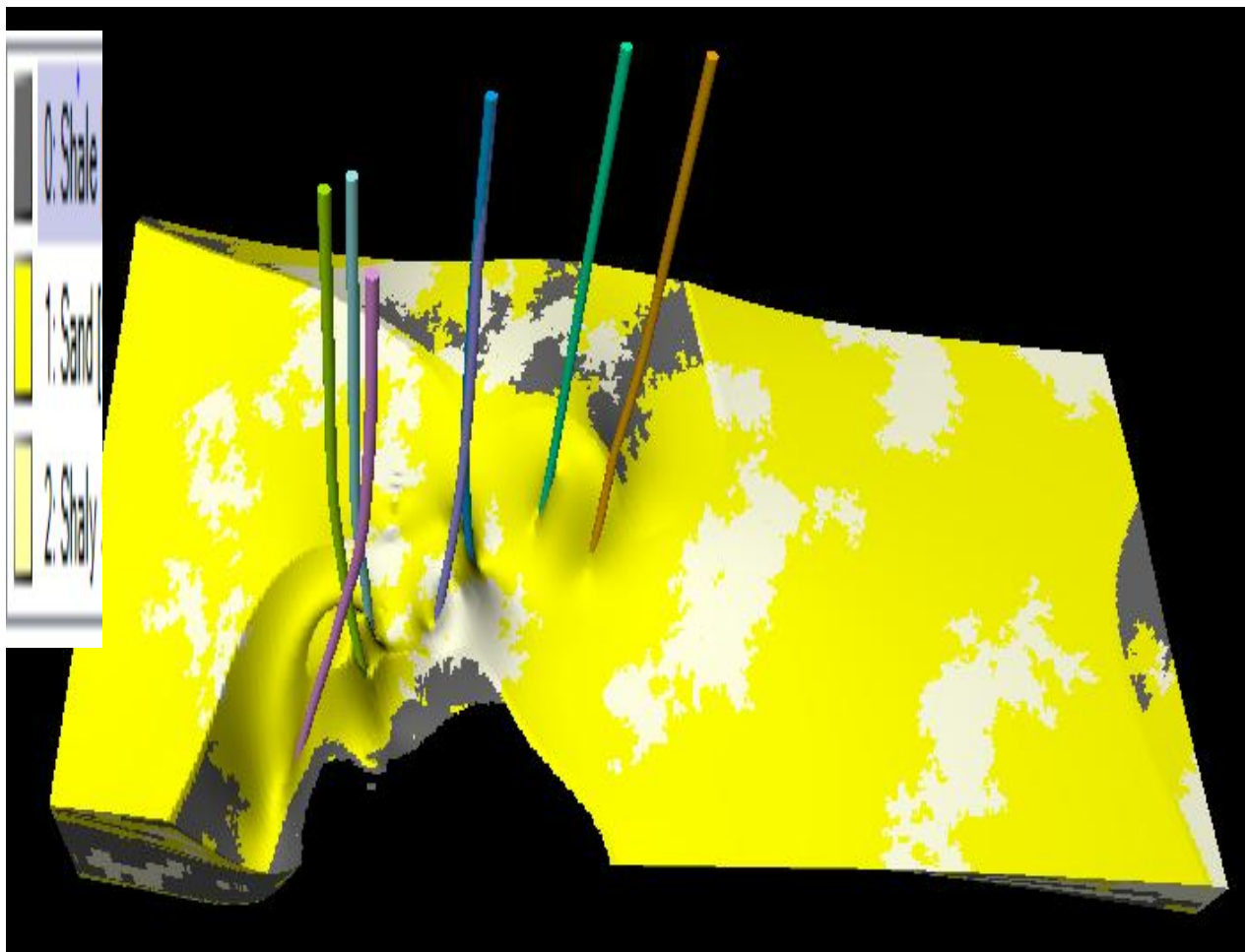


Figure 4.77: Facies Model (TOKS 3000)

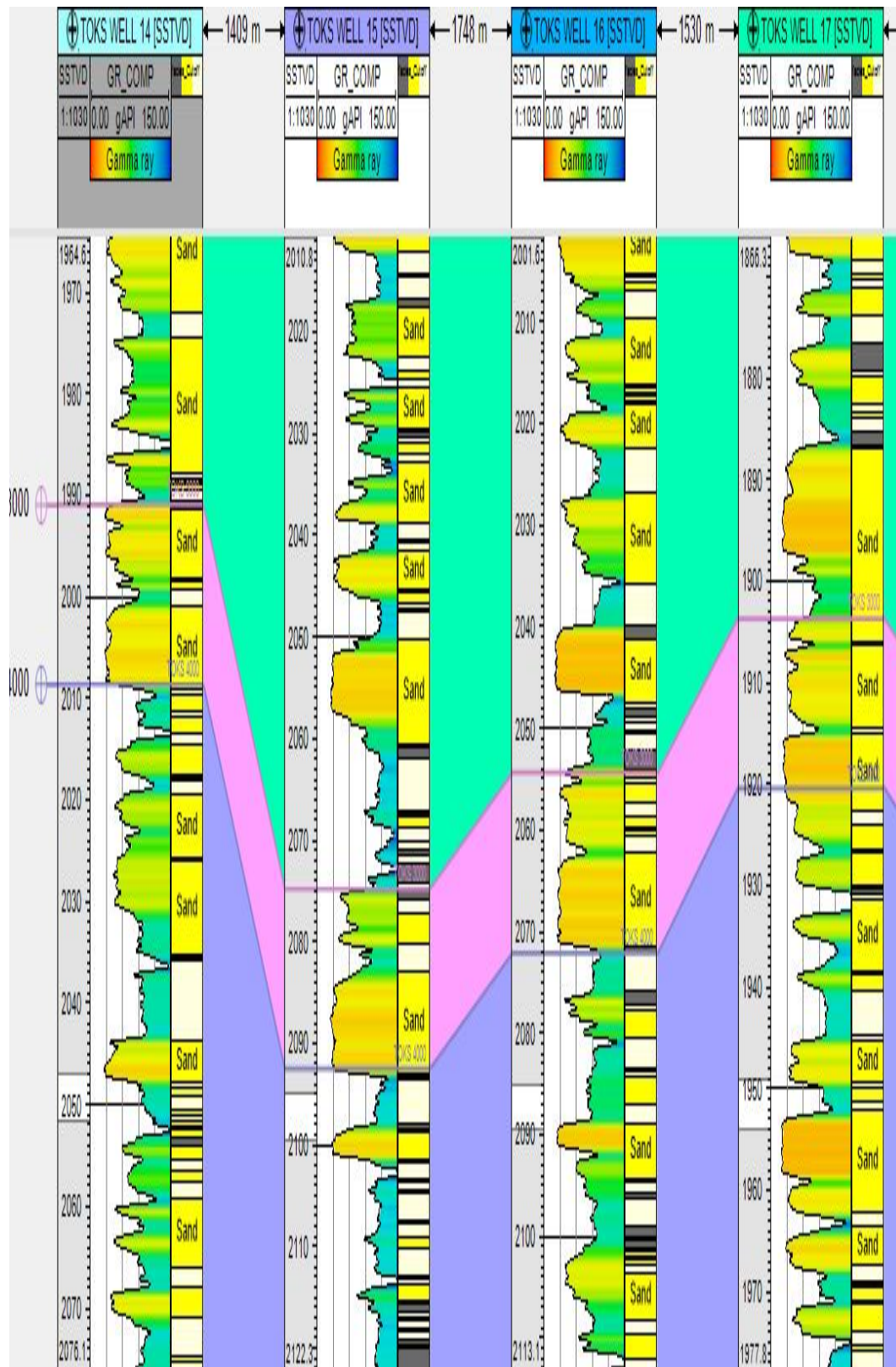


Figure 4.78: Facies Model (TOKS 3000)

Facies Model (TOKS 3000)

Reservoir Facial Modeling is a technique used in reservoir characterization to represent the heterogeneity and spatial distribution of different rock types or facies within a reservoir.

It involves dividing the reservoir into distinct facies based on their sedimentological characteristics, such as grain size, sorting, mineralogy, or sedimentary structures.

Facies model was created using sequential indicator simulation (SIS) algorithm.

Facies types considered are Sand, coarse sand and shale. The model was populated using variogram information from data analysis. The obtained results is in consistence with the works of John and Oluwaseyi (2013), Ayenimelo (2016), Anyim (2010), Danwazan, *et al.*, (2023) and Adagunodo, *et al.*, (2022).

4.5 DEPOSITIONAL ENVIRONMENT

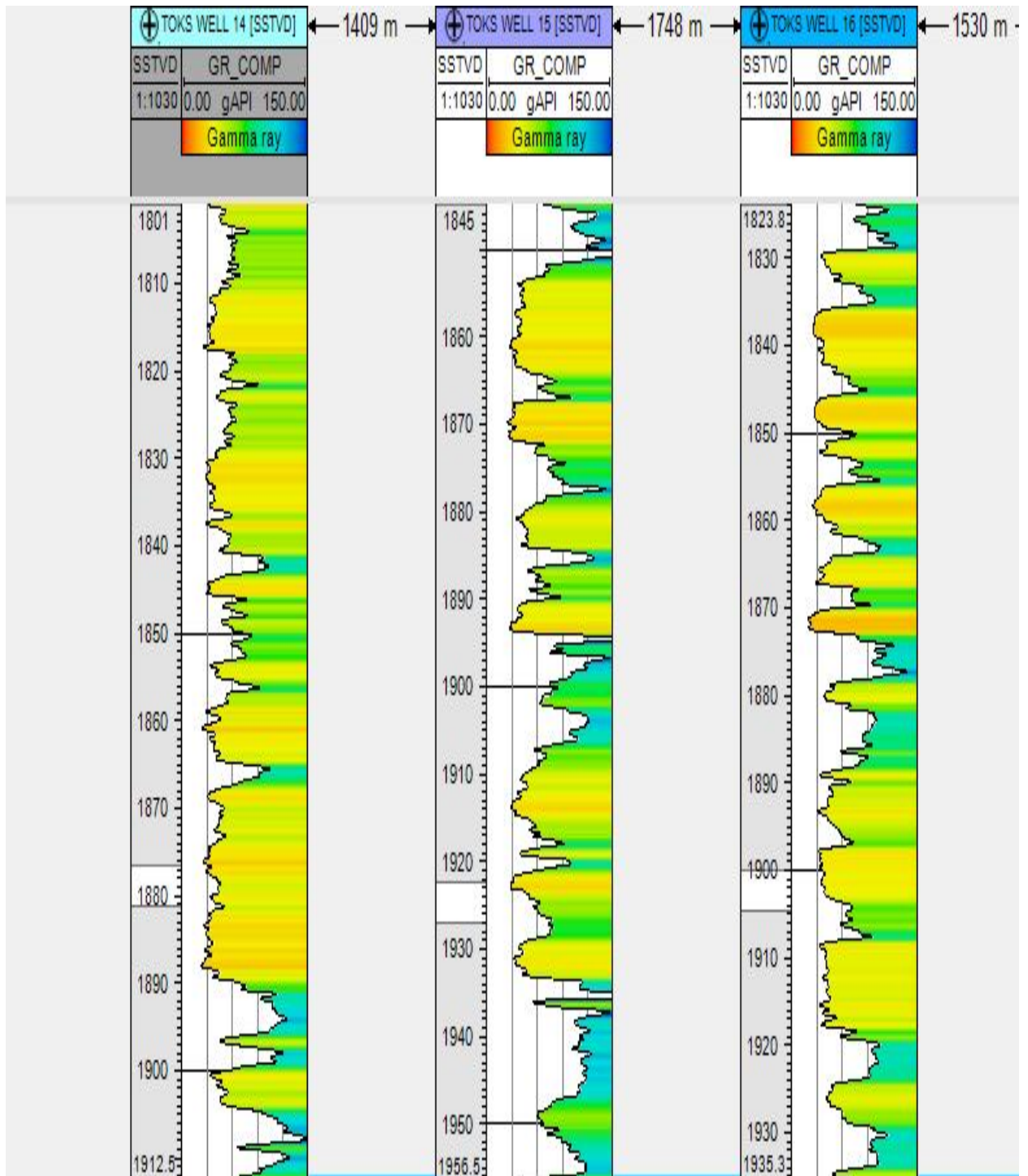


Figure 4.79: Well Log and Depositional Environment

The depositional environment of the studied wells (TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51) for TOKS 1000 in TOKS Field, Niger Delta Basin shows can be conveniently classified as a fluvial environment based on the Gamma ray log motif, lithologies and sedimentary facies. Also, the depositional environment of the studied wells (TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18 TOKS Well 19 and TOKS Well 51) for both TOKS 1000 and TOKS 3000 in TOKS Field, Niger Delta Basin shows can be conveniently classified as a fluvial environment based on the Gamma ray log motif, lithologies and sedimentary facies.

This stratigraphic sequence is a common feature of the Agbada Formation in the Niger Delta Basin. Sandstones serve as reservoirs in the field, these reservoirs are the productive zone based on the Gamma ray log motif, lithologies and sedimentary facies. The obtained results is in consistence with the works of John and Oluwaseyi (2013), Ayenimelo (2016), Anyim (2010), Danwazan, *et al.*, (2023) and Adagunodo, *et al.*, (2022).

CHAPTER FIVE

SUMMARY AND CONCLUSION

5.1 SUMMARY

The search for oil has become increasingly intense with marked technological improvement from all branches of science. In Nigeria like other countries the world all over, science and technology has made the oil industry experience a remarkably high success ratio for exploratory wells. Exploration and characterization of hydrocarbon reservoirs represent a multifaceted challenge that demands a holistic understanding of subsurface geology, rock properties, and fluid behavior. The primary sources of invaluable information for optimal reservoir evaluation and characterization are well logs, seismic data, and core data, each offering unique insights into the intricate complexities of subsurface formations.

Well log interpretations enable the construction of detailed reservoir models, which are instrumental in predicting reservoir behavior, identifying sweet spots, and optimizing production strategies in the TOK's field. Petrophysical properties which include porosity, permeability, Net-to-gross, V-Shale and water saturation of the wells aid in characterizing the reservoir by providing information about the proportion of hydrocarbon-bearing rock (net) compared to non-hydrocarbon-bearing rock (gross). Hydrocarbon reservoirs often contain multiple phases, including oil, gas and water. The water saturation model helps characterize the distribution and movement of water within the reservoir rock and better delineate the boundaries of hydrocarbon-bearing zones and estimate their volumes more accurately.

From the acoustic impedance cube result, probable hydrocarbon accumulation was observed in the zones characterized by low P-impedance values depicted between green and blue colour codes. These zones are inferred to be hydrocarbon zones based on the low P-impedance values, while the high amplitude reflectivity which is a measure of zone of interest. The results is in consistence with work of Tiekuro *et al.*, (2024)

The seismic inversion result shows a high level of accuracy with a correlation coefficient of 0.997866 in TOKS Wells. The acoustic impedance successfully resolved and improved on the resolution of the seismic stacking velocity especially at reservoir layers and at depth deeper than 3600 ms.

Moreso, In TOKS Field, well positioning is essential for maximizing recovery, post-stack inversion provides a more data-driven, geologically consistent basis for identifying the most promising drilling targets. The inversion highlight potential high-quality sand bodies or hydrocarbon-bearing intervals beyond the reach of existing wells, thus reducing geological uncertainty. Inversion refines the low-frequency model used in static modeling by incorporating seismic-derived impedance trends, improving the confidence in reservoir connectivity and volumetric distribution.

5.1.1 FINDINGS

The petrophysical parameters interpreted TOKS Well 14, TOKS Well 15, TOKS Well 16, TOKS Well 17, TOKS Well 18, TOKS Well 19 and TOKS Well 51 in TOKS Field, Niger Delta Basin Southern Nigeria reflects a very prolific reservoir, which when developed will produce maximally. The high porosities, if correlated with other parameters like the water saturation,

permeability etc. will give a prolific model for the reservoir. The reservoirs delineated were only for the log section available and so there could probably be more reservoirs.

From the logs, five (5) hydrocarbon sandstone bearing reservoirs were identified in the well section of TOKS Well 14, these were all identified at different thicknesses that range from 0.5m – 19.7m with a net thickness of 58.3m and the well contain fine grained rocks with fewer shale volumes, also water saturation in this reservoir were less than sixty percentage. Hence, the well reservoir will produce large amounts of hydrocarbon in its pore volume that will be accompanied by little or no water. The net – to – gross (NTG) for the well section at TOKS 1000 is 0.95; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. Also, the net – to – gross (NTG) for the well section at TOKS 3000 is 0.92; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. The volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 5%, this is considerably low shale volume within reservoir in the well section for TOKS 1000 while the volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 8%, this is also considerably low shale volume within reservoir in the well section for TOKS 3000. The water saturation in a reservoir is relative as an increase in water saturation will result in a decrease in hydrocarbon saturation, the water saturation in the studied well section 27.5% for TOKS 1000, this reflect a prolific reservoir and while the water saturation in the studied well section is 23.5% for TOKS 3000, also reflecting a prolific reservoir. The porosity values which is the available pore space in the reservoir in the well section is 30.5% for TOKS 1000, this is for good to excellent reservoir quality while the porosity for well section is 34.9 % for TOKS 3000, this is also for good to excellent reservoir quality.

Three (3) hydrocarbon sandstone bearing reservoirs were identified in the well section of TOKS Well 15, these were all identified at different thicknesses that range from 10m – 14.1m with a net thickness of 34.4m and the well contain fine grained rocks with fewer shale volumes, also water saturation in this reservoir were less than sixty percentage. Hence, the well reservoir will produce large amounts of hydrocarbon in its pore volume that will be accompanied by little or no water. The net – to – gross (NTG) for the well section at TOKS 1000 is 0.95; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. Also, the net – to – gross (NTG) for the well section at TOKS 3000 is 0.95; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. The volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 5%, this is considerably low shale volume within reservoir in the well section for TOKS 1000 while the volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 5%, this is also considerably low shale volume within reservoir in the well section for TOKS 3000. The water saturation in a reservoir is relative as an increase in water saturation will result in a decrease in hydrocarbon saturation, the water saturation in the studied well section 26.5% for TOKS 1000, this reflect a prolific reservoir and while the water saturation in the studied well section is 26.3% for TOKS 3000, also reflecting a prolific reservoir. The porosity values which is the available pore space in the reservoir in the well section is 31.0% for TOKS 1000, this is for good to excellent reservoir quality while the porosity for well section is 31.2% for TOKS 3000, this is also for good to excellent reservoir quality.

Two (2) hydrocarbon sandstone bearing reservoirs were identified in the well section of TOKS Well 16, these were all identified at different thicknesses that range from 10.2m – 19.6m with a net thickness of 29.8m and the well contain fine grained rocks with fewer shale volumes,

also water saturation in this reservoir were less than sixty percentage. Hence, the well reservoir will produce large amounts of hydrocarbon in its pore volume that will be accompanied by little or no water. The net – to – gross (NTG) for the well section at TOKS 1000 is 0.95; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. Also, the net – to – gross (NTG) for the well section at TOKS 3000 is 0.95; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. The volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 5%, this is considerably low shale volume within reservoir in the well section for TOKS 1000 while the volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 5%, this is also considerably low shale volume within reservoir in the well section for TOKS 3000. The water saturation in a reservoir is relative as an increase in water saturation will result in a decrease in hydrocarbon saturation, the water saturation in the studied well section 27.9% for TOKS 1000, this reflect a prolific reservoir and while the water saturation in the studied well section is 26.2% for TOKS 3000, also reflecting a prolific reservoir. The porosity values which is the available pore space in the reservoir in the well section is 30.4% for TOKS 1000, this is for good to excellent reservoir quality while the porosity for well section is 31.4% for TOKS 3000, this is also for good to excellent reservoir quality.

Seven (7) hydrocarbon sandstone bearing reservoirs were identified in the well section of TOKS 17, these were all identified at different thicknesses that range from 9.5m – 20.7m with a net thickness of 81.3m and the well contain fine grained rocks with fewer shale volumes, also water saturation in this reservoir were less than sixty percentage. Hence, the well reservoir will produce large amounts of hydrocarbon in its pore volume that will be accompanied by little or no water. The net – to – gross (NTG) for the well section at TOKS 1000 is 0.96; this NTG is

relatively high which relate to a prolific reservoir based on the individual reservoir thickness. Also, the net – to – gross (NTG) for the well section at TOKS 3000 is 0.96; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. The volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 4%, this is considerably low shale volume within reservoir in the well section for TOKS 1000 while the volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 4%, this is also considerably low shale volume within reservoir in the well section for TOKS 3000. The water saturation in a reservoir is relative as an increase in water saturation will result in a decrease in hydrocarbon saturation, the water saturation in the studied well section 25.2% for both TOKS 1000 and TOKS 3000, also reflecting a prolific reservoir. The porosity values which is the available pore space in the reservoir in the well section is 32.5% for both TOKS 1000 and TOKS 3000, this percentage is for good to excellent reservoir quality.

Four (4) hydrocarbon sandstone bearing reservoirs were identified in the well section of TOKS Well 18, these were all identified at different thicknesses that range from 0.8m – 10.3m with a net thickness of 31.1m and the well contain fine grained rocks with fewer shale volumes, also water saturation in this reservoir were less than sixty percentage. Hence, the well reservoir will produce large amounts of hydrocarbon in its pore volume that will be accompanied by little or no water. The net – to – gross (NTG) for the well section at TOKS 1000 is 0.96; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. Also, the net – to – gross (NTG) for the well section at TOKS 3000 is 0.92; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. The volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 4%, this is considerably low shale volume within reservoir in the well section for TOKS 1000

while the volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 8%, this is also considerably low shale volume within reservoir in the well section for TOKS 3000. The water saturation in a reservoir is relative as an increase in water saturation will result in a decrease in hydrocarbon saturation, the water saturation in the studied well section 26.8% for TOKS 1000, this reflect a prolific reservoir and while the water saturation in the studied well section is 24.5% for TOKS 3000, also reflecting a prolific reservoir. The porosity values which is the available pore space in the reservoir in the well section is 30.5% for TOKS 1000, this is for good to excellent reservoir quality while the porosity for well section is 33.5% for TOKS 3000, this is also for good to excellent reservoir quality.

Seven (7) hydrocarbon sandstone bearing reservoirs were identified in the well section of TOKS Well 19, these were all identified at different thicknesses that range from 0.2m – 10m with a net thickness of 49.9m and the well contain fine grained rocks with fewer shale volumes, also water saturation in this reservoir were less than sixty percentage. Hence, the well reservoir will produce large amounts of hydrocarbon in its pore volume that will be accompanied by little or no water. The net – to – gross (NTG) for the well section at TOKS 1000 is 0.95; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. Also, the net – to – gross (NTG) for the well section at TOKS 3000 is 0.92; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. The volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 5%, this is considerably low shale volume within reservoir in the well section for TOKS 1000 while the volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 5%, this is also considerably low shale volume within reservoir in the well section for TOKS 3000. The water saturation in a reservoir is relative as an increase in water saturation will

result in a decrease in hydrocarbon saturation, the water saturation in the studied well section 26.4% for TOKS 1000, this reflect a prolific reservoir and while the water saturation in the studied well section is 28.5% for TOKS 3000, also reflecting a prolific reservoir. The porosity values which is the available pore space in the reservoir in the well section is 31.1% for TOKS 1000, this is for good to excellent reservoir quality while the porosity for well section is 28.8 % for TOKS 3000, this is also for good to excellent reservoir quality.

Three (3) hydrocarbon sandstone bearing reservoirs were identified in the well section of TOKS Well 51, these were all identified at different thicknesses that range from 10.2m – 20m with a net thickness of 47.7m and the well contain fine grained rocks with fewer shale volumes, also water saturation in this reservoir were less than sixty percentage. Hence, the well reservoir will produce large amounts of hydrocarbon in its pore volume that will be accompanied by little or no water. The net – to – gross (NTG) for the well section at TOKS 1000 is 0.93; this NTG is relatively high which relate to a prolific reservoir based on the individual reservoir thickness. The volume of shale in the reservoir in relation to the gamma ray index, I_{GR} , for well section is 5%, this is considerably low shale volume within reservoir in the well section for TOKS 1000. The water saturation in a reservoir is relative as an increase in water saturation will result in a decrease in hydrocarbon saturation, the water saturation in the studied well section 29.7% for TOKS 1000, this reflect a prolific reservoir. The porosity values which is the available pore space in the reservoir in the well section is 38.6% for TOKS 1000, this is for good to excellent reservoir quality.

From the acoustic impedance cube result, probable hydrocarbon accumulation was observed in the zones characterized by low P-impedance values depicted between green and blue colour codes. These zones are inferred to be hydrocarbon zones based on the low P-impedance

values, while the high amplitude reflectivity which is a measure of zone of interest. The acoustic impedance successfully resolved and improved on the resolution of the seismic stacking velocity especially at reservoir layers and at depth deeper than 3600 ms. Acoustic impedance being a layer property has shown improvement on the lateral and vertical resolution of the data beyond what the usual seismic interval velocity could image. The seismic inversion result shows a high level of accuracy with a correlation coefficient of 0.997866 in TOKS Wells. The results is in consistence with works of Mbou *et al.*, (2024) and Tiekuro *et al.*, (2024)

Post-stack seismic inversion of the wells in TOKS Field aid in the generation of a high-resolution acoustic impedance (AI) cube, water saturation cube, for predicting lithological and petrophysical properties across the field, especially in undrilled locations. The results is in consistence with work of Tiekuro *et al.*, (2024)

Essentially, the Petrophysical analysis of TOK 1000 for the TOKS wells 14, 15,16,17,18, 19 and 51 shows porosity value of 0.3054, 0.3103, 0.3042, 0.3252, 0.3055, 0.3108, 0.3857. Water saturation values of the wells as 0.2750, 0.2645, 0.2788, 0.2521, 0.2684, 0.2638 and 0.2972. The shale volume results shows 0.05, 0.05, 0.04, 0.04, 0.05, 0.07. The Net to gross ratio result shows 0.95, 0.95, 0.95, 0.96, 0.96, 0.95, 0.93.

The Petrophysical analysis of TOK 3000 for the TOKS wells 14, 15,16,17,18 and 19 shows porosity value of 0.3491, 0.3121, 0.3135, 0.2993, 0.3353, 0.2881. Water saturation values of the wells as 0.2349, 0.2627, 0.2615, 0.2741, 0.2446 and 0.2846. The shale volume results shows 0.08, 0.05, 0.05, 0.04, 0.08 and 0.05. The Net to gross ratio result shows 0.92, 0.95, 0.95, 0.96, 0.92 and 0.95.

The seismic interpretation (Horizon and seed) of reservoir tops of TOKS 1000 and TOKS 3000 correspond to trough events.

5.1.2 CONTRIBUTION TO KNOWLEDGE

- i. Establishment of reservoir sand interval and of the reservoir zones of the TOKS wells of TOKS Field Greater Ughelli Depobelt, Niger Delta Basin, Southern Nigeria.
- ii. Generation of time-depth relationship across the wells of TOKS Field Greater Ughelli Depobelt, Niger Delta Basin, Southern Nigeria.
- iii. Identification of depositional environments of the studied wells of TOKS Field Greater Ughelli Depobelt, Niger Delta Basin, Southern Nigeria.
- iv. Uncertainty can be reduced by a blend of RMS amplitude and seismic inversion in identifying reservoirs for accurate well placements.

5.2 CONCLUSIONS

From the reservoir characterization and evaluation of TOKS Field, Greater Ughelli Depobelt, Niger Delta Basin, Nigeria, sandstone reservoir were identified at different depths and with varying thicknesses. The evaluated reservoirs have favorable petrophysical characteristics that will lead to excellent production of hydrocarbon from their porespace hence regarded as prospective wells. The prospective reservoirs were coarse grained.

All the reservoirs had favorable petrophysical characteristics that had excellent production of hydrocarbon from their pore spaces hence regarded as a producing well. The reservoirs were coarse grained with high percentage porosity.

The wells contains fine grained rocks with fewer shale volumes. Water saturation in this reservoir were less than sixty percentage. Hence, the reservoir will produce large amounts of hydrocarbon in its pore volume that will be accompanied by little or no water.

The acoustic impedance successfully resolved and improved on the resolution of the seismic stacking velocity especially at reservoir layers and at depth deeper than 3600 ms. The generation of a high-resolution acoustic impedance (AI) cube, water saturation cube, for predicting lithological and petrophysical properties across the field, especially in undrilled locations.

5.2.1 RECOMMENDATION

It is strongly recommended that more integrated approach should be adopted in de-risking prospects and encourage investors confidence. Results from such analysis of data will help to make more objective decisions on reservoir development and production.

Data data like ditch cuttings and cores should be made available by the exploration (E) and production (P) companies to researchers so as to fully characterize the TOKS Field, Niger Delta Basin, Southern Nigeria.

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APPENDIX

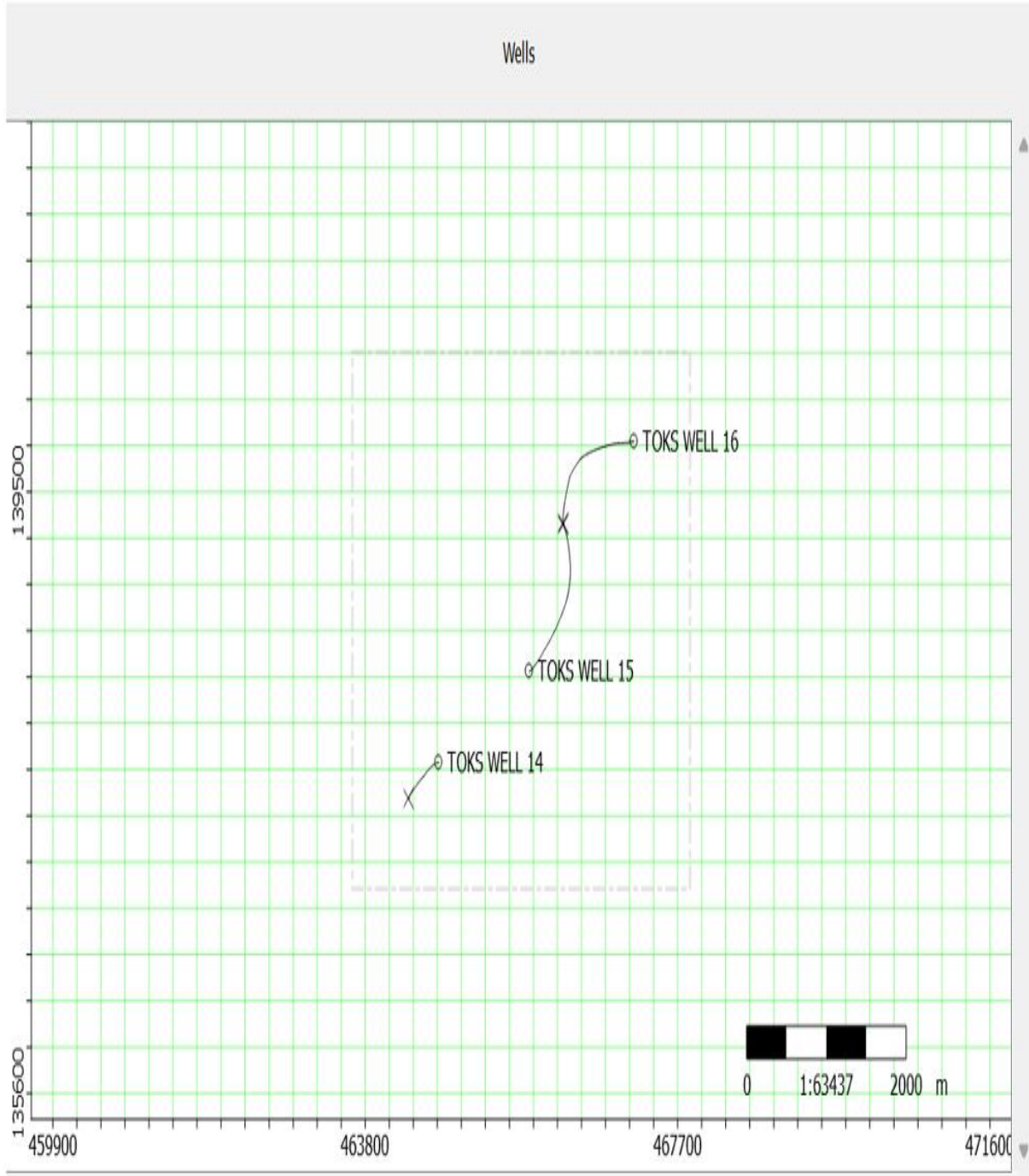


Plate 1: TOKS Field Importation Base map

Selected SEG-Y File: TOKS 3D Seismic New.segy

Volume Name: TOKS 3D Seismic New

Amplitude Type: Seismic Amplitude Unit:

Domain : Time ms

This is a Post-stack volume. Bin Type: Offset

Do you have Inline and Xline numbers in the trace headers? Yes No

Do you have X & Y coordinates in the trace headers? Yes No

Primary key for assigning traces to bin location: Inline and Xline Header Editor...

Renumber the CDPs sequentially (suggest Yes for 3D, No for 2D)? Yes No

The program needs to create some files for storing information about the volume. By default, the information files are created where your input Segy file is located, but you can specify a directory path below.

Create information files in this directory: C:\Users\USER\Desktop\Tochi Inversion\ ...

Plate 2: Seismic importation process

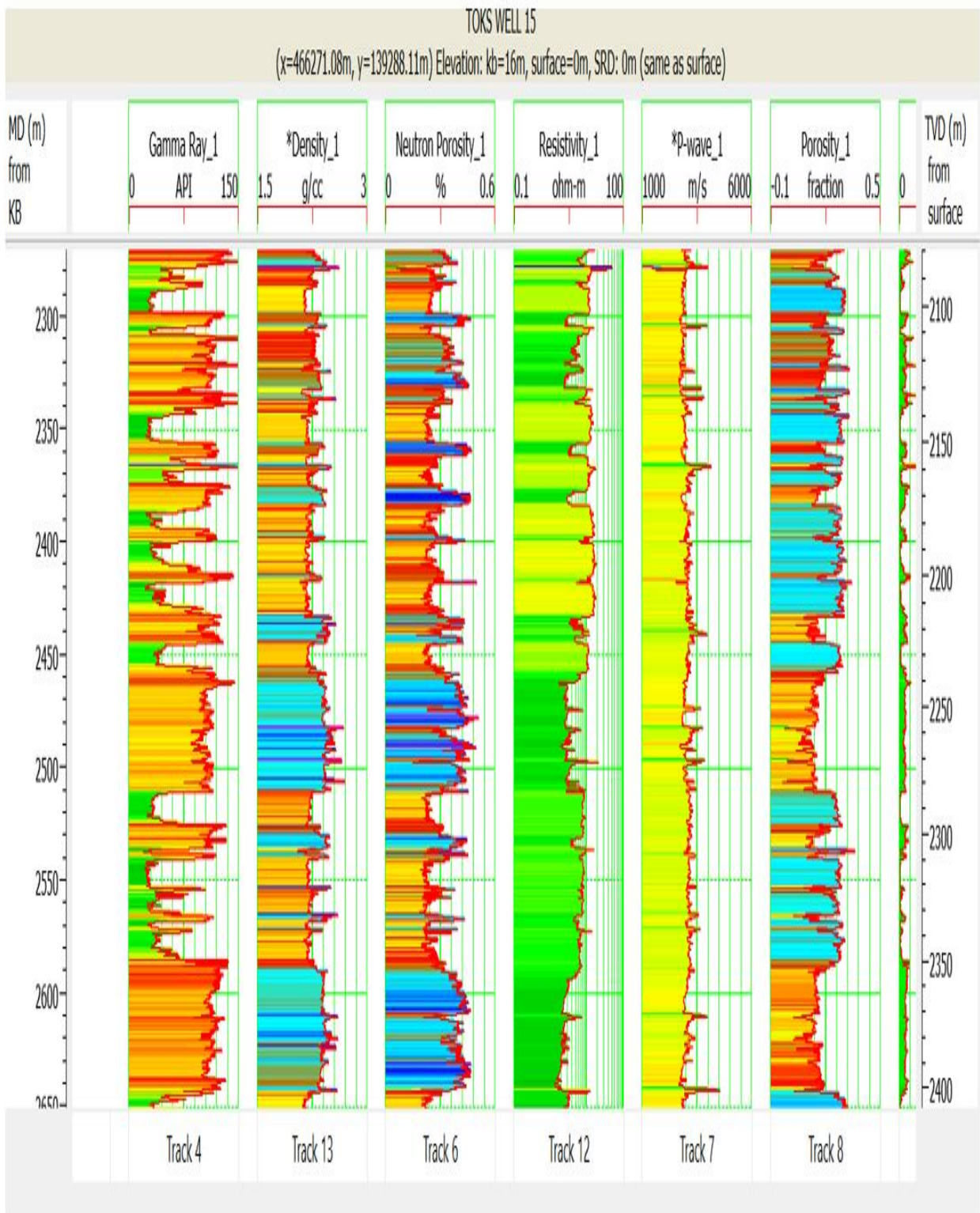


Plate 3: Combine Petrophysical Well log of TOKS Field

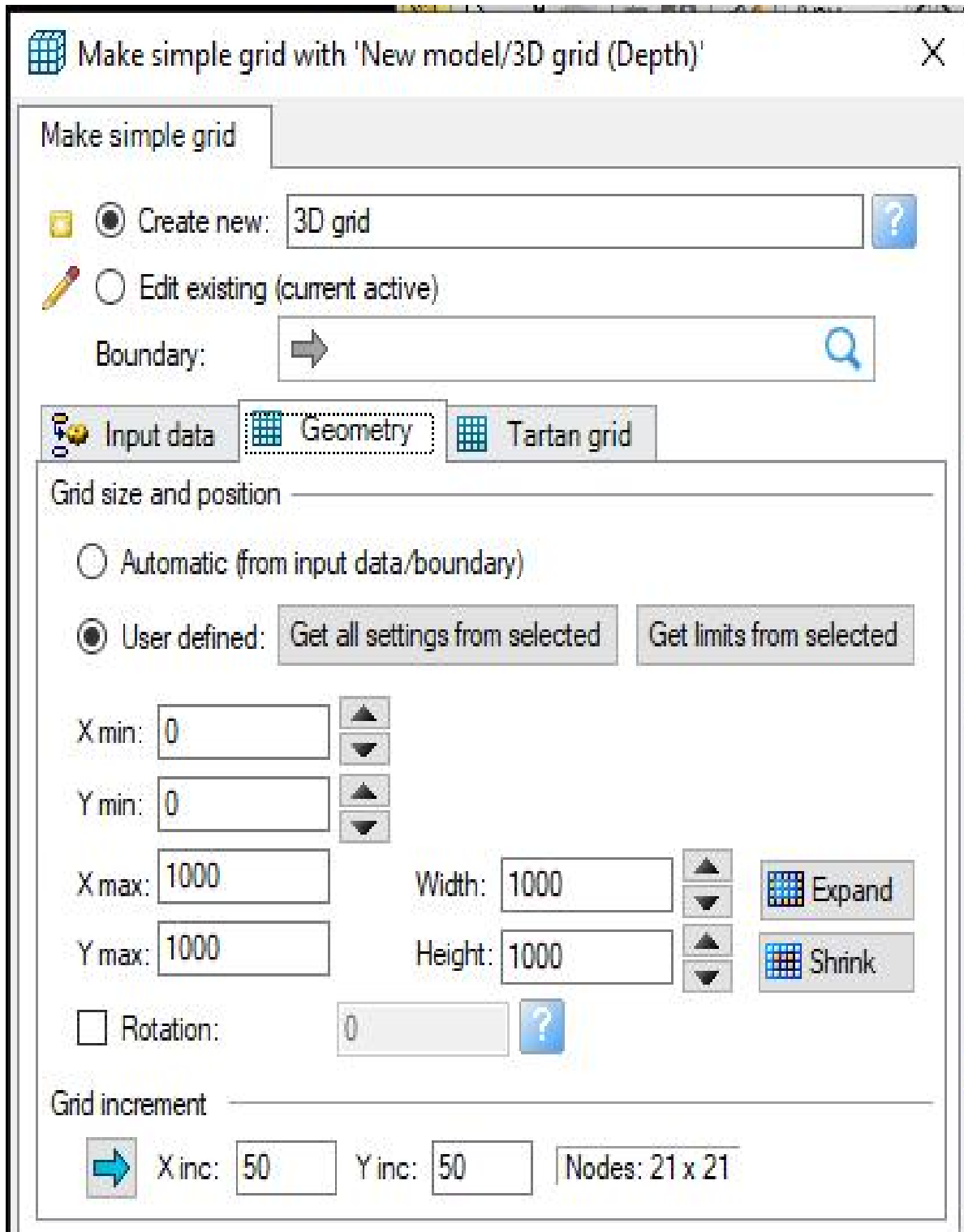


Plate 4: Reservoir Gridding of TOKS Wells

WELL DATA IMPORTATION

Table 4: Showing Well log importation process.

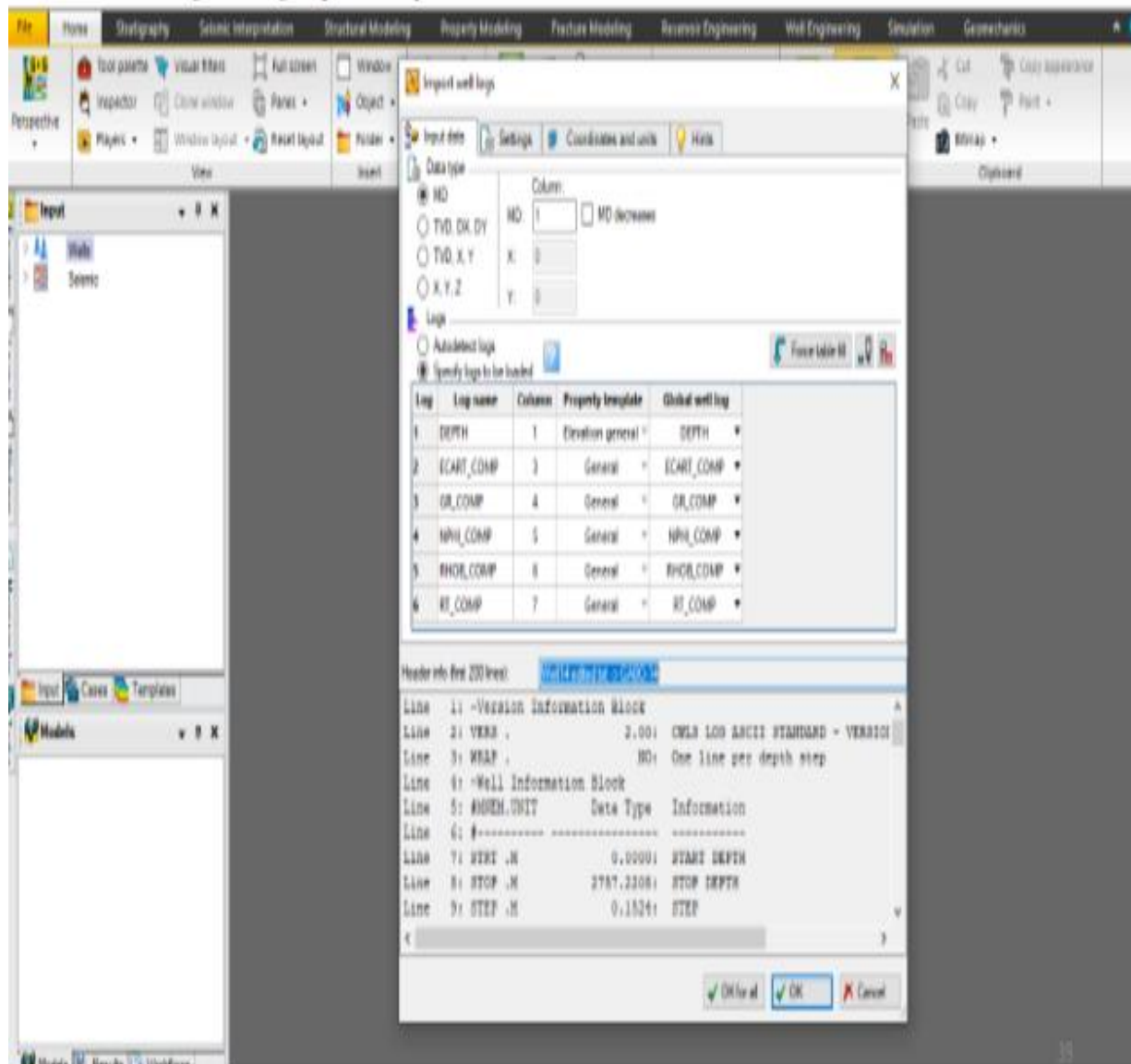


Plate 5: TOKS Wells Data Importation

m

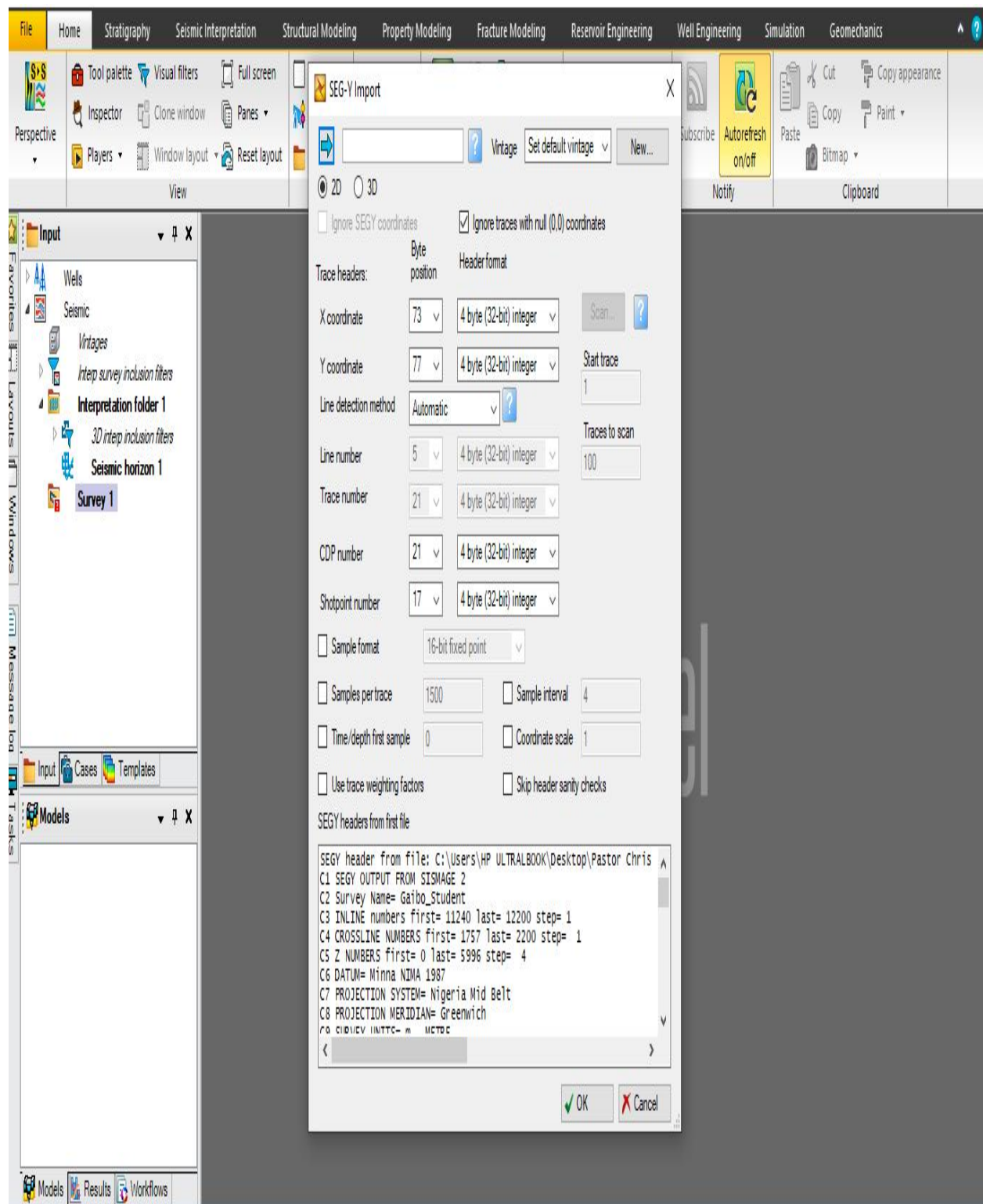


Plate 6: TOKS Wells Seismic Importation