UNIVERSIDADE EDUARDO MONDLANE

FACULTY OF ENGINEERING

WELL-DATA-DRIVEN 3D GEOLOGICAL MODELLING OF RESERVOIRS: XIAERMEN OILFIELD CASE STUDY

By

TARCISIO CARDOSO

A dissertation submitted in partial fulfillment of
the requirement for the degree of

MASTER OF SCIENCE IN PETROLEUM ENGINEERING

Maputo

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ABSTRACT

This research focused on creating a 3D geological model using well data, to enhance model accuracy and support the economic development planning of the Xiaermen oilfield. Data from 40 well were utilized, resulting in a more detailed and accurate model. A sequential workflow was adopted, beginning with large scale (discrete proprieties) and progressing to smaller scale proprieties characterized by greater uncertainty, modeled using a geostatistical method to analyze their distributions across the reservoir.

The Sequential Indicator Simulator and Sequential Gaussian Simulation Algorithms were used under stochastic model to distribute reservoir proprieties effectively. This study underscores the importance of well-data-driven 3D Geological Modelling in Reservoir Characterization, highlighting the used methodology in this domain.

By integrating a diverse data source, this study identified critical geological feature such as facies distributions, porosity variations and fluid saturations enabling robust decision-making processes. Incorporating well data with seismic information, allowed geoscientists to correlate seismic attributes with reservoir properties, significantly improving the accuracy of the resulting geological models. This integration also provided a more precise understanding of the reservoir's structural framework, fault systems, and stratigraphic variations, essential for optimized reservoir management and development.

Keywords: Xiaermen oilfield, Well-data-driven modelling, Reservoir

DEDICATION

To my family

Kwani, Tarcísio Jr., Cremildo and my wife Sandra

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LIST OF ABBREVIATIONS

Symbol	Definition
A	Reservoir area (acres)
B	Contour interval
Bg	Gas formation volume factor, bbl/SCF
Bo	Oil formation volume factor, bbl/STB
Boi	Initial oil formation volume factor, bbl/STB
Bt	Two-phase formation volume factor, bbl/STB
Cf	Formation compressibility, psia-1
EER	Estimated remaining reserves
EUR	Estimated ultimate recovery
Gp	Cumulative gas produced, SCF
h	Thickness (ft)
M	Mean of the parent distribution, such as barrels of oil
STOOIP	Stock Tank Original Oil In Place, STB
NP	Cumulative Oil Production
Sw	Average reservoir water saturation
SGS	Sequential Gaussian simulation
SIS	Sequential indicator simulation

Chapter I – INTRODUCTION

1.1 Introduction

In the realm of hydrocarbon exploration and production, accurate and comprehensive geological models play a vital role in understanding subsurface reservoirs. These models are critical for field development strategies and decisions making. Over the years, the advancement of data-driven techniques has revolutionized the way reservoirs are characterized and modelled, leading to improved accuracy and efficiency. This method harnesses the power of diverse well data, including well logs, core samples, seismic data, and production data, to construct detailed and realistic geological models. By integrating a wide range of data sources, this approach offers a holistic understanding of reservoir properties and facilitates robust decision-making processes.

The foundation of well-data-driven 3D geological modelling of reservoirs lies in the utilization of advanced computational algorithms, machine learning techniques, and artificial intelligence. These technologies facilitate the extraction of meaningful insights from vast amount of well data, allowing geoscientists and reservoir engineers to develop a comprehensive understanding of the subsurface geology and fluid dynamics. This approach enables the identification of critical geological features, such as facies distributions, porosity variations, and fluid saturations, which are crucial for optimizing production strategies and mitigating risks. The combination, improve the accuracy of the resulting geological models and understanding of the reservoir's structural framework, fault systems and stratigraphic variations.

Furthermore, well-data-driven 3D geological modelling offers dynamic capabilities by incorporating production data, including pressure data, fluid production rates, and reservoir pressure behavior over time. These models, represents a paradigm shift in the way reservoir characterization is performed, driven by diverse well data sources. This dissertation aims to highlight the significance of well-data-driven 3D geological modelling in reservoir characterization.

1.2 Background of the Study

Reservoir modelling refers to a process, where available data and knowledge from subsurface are transferred into a computerized numerical presentation. It involves the creation of a 3D representation of subsurface geological structures and fluid reservoirs based on available data and information. These models contribute to the understanding of the reservoir's behavior, identifying potential hydrocarbon-bearing zones, and optimizing production strategies. They serve as a foundation for decision-making processes related to drilling, well placement, enhanced oil recovery techniques, and overall reservoir management.

Traditionally, reservoir modelling relied on deterministic interpolation techniques, such as kriging or variogram analysis, to estimate reservoir properties from well data. These methods assumed spatial continuity and relied on manual interpretation and subjective judgment. However, they often struggled to accurately represent complex geological structures and heterogeneities within the reservoir, leading to uncertainties in reservoir characterization. Well-data-driven 3D geological modelling approaches aim to overcome the limitations of traditional techniques by incorporating a wide range of data sources, including well logs, seismic data, production data, and geophysical measurements.

Well-data-driven 3D geological modelling allows for a more accurate characterization of reservoir properties by honoring geological constraints and capturing spatial variations. These models facilitate uncertainty quantification, allowing for probabilistic assessment and risk analysis in reservoir management, considering multiple realizations and scenarios, this process is continuous, beginning at the field discovery stage and extending through the subsequent phases of production and abandonment.

1.3 Statement of the Problem

Traditional reservoir modelling approaches often struggle to accurately represent the complex heterogeneity present in subsurface reservoirs. Methods rely on deterministic interpolation techniques that may overlook small-scale variations and fail to capture the intricate geological structures and fluid flow pathways within the reservoir. As a result, the generated reservoir models may not accurately represent the true distribution of reservoir properties, leading to uncertainties in reservoir characterization due to the limited availability of data and the inherent variability of subsurface reservoirs. There is a need for well-data-driven modelling approaches that incorporate uncertainty quantification techniques to provide more robust and reliable reservoir predictions. As reservoir models become increasingly complex and the size of available datasets grows, there is a growing demand for scalable and computationally efficient modelling techniques. Traditional methods may struggle to handle large-scale datasets and require substantial computational resources and time for model construction and analysis. Developing well-data-driven 3D geological modelling approaches that can effectively handle big data sets.

The field of well-data-driven 3D geological modelling of reservoirs is relatively new, the absence of widely accepted methodologies for evaluating the accuracy and reliability of these models poses challenges in comparing different approaches and assessing their performance. Addressing these problems and challenges in well-data-driven 3D geological modelling of reservoirs contribute to more accurate reservoir characterization, improved production optimization, and enhanced decision-making processes in reservoir management.

1.4 Research Objectives

1.4.1 General Objective

To apply the well data-driven 3D geological modelling techniques for Xiaermen oilfield reservoir characterization.

1.4.2 Specific Objectives

1. Develop an integrated 3D geological framework model for integrated well data for reservoir construction;
2. Determine petrophysical reservoir properties;
3. Evaluate the reservoir quantity and the potential area.

1.5 Research Questions

Research Questions:

1. How can well-data-driven 3D geological modelling techniques improve the reservoir characterization?
2. What methodologies can be effectively integrated in the well data, to enhance the accuracy of reservoir models?
3. How does the application of well-data-driven 3D geological modelling techniques impact on the reservoir management practices?

Addressing these research questions, we can gain insights into the effectiveness of well-data-driven 3D geological modelling approaches, advance the field's knowledge, and provide practical recommendations for improving reservoir characterization and decision-making processes in reservoir engineering and geology.

1.6 Significance of the Study

The well-data-driven 3D geological modelling of reservoirs holds significant importance in improving reservoir characterization. This enhanced reservoir characterization provides valuable insights into reservoir properties, heterogeneity, fluid flow behaviour, and connectivity, enabling better decision-making processes in reservoir management. Accurate reservoir models resulting from well-data-driven modelling techniques facilitate improved production optimization, leads to increased hydrocarbon recovery, reduced operational costs, and improved overall production performance. Well-data-driven 3D geological modelling enables robust uncertainty quantification and risk analysis in reservoir management, considering multiple realizations and scenarios; decision-makers can assess the range of potential outcomes and associated risks. The study of well-data-driven modelling techniques emphasizes the integration and utilization of well data for comprehensive analysis. Integration enables a more accurate representation of subsurface reservoirs and improves the reliability of reservoir models.

1.7 The Scope of the Study

This dissertation focuses on the integration of well data, to construct a holistic representation of reservoir properties and characteristics. An important aspect of this method is to assess and quantify uncertainties associated with data limitations, model assumptions, and parameter estimation. This enables probabilistic assessment and risk analysis in reservoir management decision-making processes. Additionally, the study will not cover aspects related to drilling operations, well completion, or production engineering, as the main focus is on the geological modelling aspects of reservoir characterization.

1.8 Definition of Key Terms

Reservoir Modelling: refers to the process of creating a three-dimensional representation of subsurface geological structures and fluid reservoirs based on available data and information. It involves characterizing reservoir properties, such as lithology, porosity, permeability, and fluid saturation, to understand the behavior and potential of hydrocarbon reservoirs.

Well Data: is the information acquired through drilling and logging operations in oil and gas wells. It includes measurements and observations related to the subsurface, such as well logs, core samples, well tests, and production data.

3D Geological Modelling: process that involves creating a three-dimensional representation of geological structures and features in the subsurface.

Well-Data-Driven Modelling: an approach in which the modelling process heavily relies on well data.

Reservoir Characterization: process of describing and understanding the properties and behaviour of a reservoir. It involves analyzing various data sources, such as well logs, seismic data, and production data, to determine reservoir properties, fluid distribution, connectivity, and reservoir boundaries.

Decision-Making Processes: the choices and actions taken based on the insights and information provided by the reservoir models.

Chapter II - LITERATURE REVIEW

2.1 Introduction

This chapter presents the literature related to the study. The chapter is divided into three parts, including literature on Reservoir Modelling Workflow, theoretical literature and the research gap. In order to conduct this review of literature different articles, journals, books, and documents were the source of secondary information to build a 3D geological model of H2V formation using well data, a case study of Xiaermen Oilfield in China. The main focuses under this chapter was to identify the literature that elaborate more on how to build a 3D geological model with relationship to production challenges facing a case study area Xiaermen oilfield.

2.2 The Reservoir Modelling Workflow

According to Tureyen (2005), building a numerical reservoir model requires the following frameworks:

1. The structural and reservoir framework;
2. The depositional and geostatistical framework;
3. The reservoir flow simulation framework. Whereby, under structural and reservoir framework stage, the general structural design of the reservoir is shown. Under depositional and geostatistical framework, it shown how facies and petrophysical information distributed. The last stage framework, reservoir flow simulation framework are, deals with production and PVT (Pressure, Volume, and Temperature) data.

Reservoir modelling can be modelled using two types of data: Static and dynamic data. Where Static hard data, includes core data, which gives information of a reservoir in a fine scale and scattered, while static soft data, such as seismic, gives information of the reservoir at a larger scale. By the use of good geostatistical modelling methods, static data are well integrated and distributed into a reservoir (Tureyen, 2005). Dynamic data which includes pressure as well as flow data are mostly used during a dynamic model to simulate the flow of fluid in the reservoir.

2.3 Reservoir modelling approach

2.3.1. Reservoir Modelling challenges

According to Tureyen (2005), the main challenge in modelling a reservoir is to bring such multiscale data all together and put in a single numerical model while accounting for their dissimilarity in scale, their accuracy and redundancy level.

2.3.2. Reservoir production challenges facing Xiaermen Oilfield

The discussion about the optimization of reservoir, using reservoir model and numerical simulation method due to the decline of oil production performance is not new (Zhizhan, 1998). Reservoir studies improve its mobility ratio, its heterogeneity and increase its sweeping efficiency due to high permeability, severe heterogeneity as well as high oil viscosity of the reservoir. The study used polymer flooding technique and there was an increase of 10% of recovery efficiency. Xie (2007), conducted a study on this oilfield by the use of Numerical Simulation method, results showed an increase in oil recovery from 6.08% to 13.22%, likewise on core flooding analysis experiment after application of Cross-Linked Polymer Flooding in Xiaermen oilfield, the study showed positive results in increasing oil recovery.

Also, the study showed good results on changing operational strategies, well locations, and well patterns on both methods used core experiment and in numerical simulation results. This study paves a way to allow different dynamic adjustments on production plans to be applied to the reservoir model to increase the recovery of the remaining oil in the reservoir.

An optimized study performed on Xiaermen oil field by numerical simulation method, where two adjustment plans were set and compared their results to get an optimal production adjustment plan. The plans Plan2005 and plan2006B were performed only under H2VII formation of the reservoir. And the best plan was Plan2006 as it showed an increase in its recovery from 16.8% up to 26.1%, hence the enhanced oil recovery was 3.8% which was better than the initial Plan2005 (Guan, 2012).

Previous studies on Xiaermen oilfield based on decline analysis method by using Matlab (Xie, 2015), with the purpose to predict future production of oil wells via its decline analysis, which findings showed that LL - model obtained was much applicable for predicting the future production of Xiaermen oilfield, where water cut of the field is very high up to 99.6% setting a limit to progress with production in the field for a very short time. This constitutes an opportunity for further studies to be conducted on the same field in order to improve the predicted results and to maximize oil production.

2.4. Previous studies on Reservoir Optimization

Studies on reservoir modelling and simulation for optimizing recovery performance of one of the Iranian oil fields indicated that by using black oil reservoir simulator, different production strategies were developed to optimize oil recovery in the field (Sajjadian, 2006). This comes due to the decline of reservoir production rate compared to the rate at the beginning of production. The decline of production was due to low permeability and porosity of the reservoir, i.e. 1-3 md and 5-20 % respectively. The best production strategy obtained with higher oil recovery and economical through conducting different well configuration on different injection techniques, by injecting water or/and gas into the reservoir.

Moreover, according to Yu (2007), it has been reached this far for the oil companies to use modelling and numerical simulation to conduct a study only because of minimizing field practical risk and lowering running cost by doing trials for the error on the output production of the reservoir, since it’s hard to know well a reservoir because they are normally associated with high complexity characteristics and features, and their models have thousands of unknowns and many constraints.

From the above study performed on Xiaermen oilfield, it is shown that a reservoir has complicated geological structure in its heterogeneity, oil viscosity that lead to complications on its oil recovery, hence more advanced and detailed study should be done to optimize its recovery. Also, because there is more residual economical potential on this oil formation. From the present proposed work, a detailed study on reservoir model through single formation horizon H2V Formation in Xiaermen Oilfield was done and come up with a 3D geological model, which can be used for future field development plans.

2.5. Measures to be employed to improve a 3D geological model

This research focused on building a geological model from well data to 3D geological model, intending to improve and increase model accuracy through available well data, for the future economic development plan for Xiaermen oilfield. An integration among geophysics, geology, fluid dynamics, geomechanics and management is truly essential, but requires specific approaches and procedures for generating and calibrating the reservoir model. This constitutes an opportunity, however, for a multidisciplinary project team, and demands abilities to deal with all and each of these aspects.

2.6. The Gap in the Literature

From the previous studies review, it is revealed that Xiaermen oilfield has serious production challenges because it has passed through many adjustment production plans. Reservoir modelling and characterization techniques focuses on integrating the available data and geological interpretation to give out the accurate description of the subsurface environment. Therefore, this research focus on building a geological model from well data to 3D geological model, intending to improve and increase model accuracy through available well data, for the future economic development plan of Xiaermen oilfield.

Several scholars such as Journal (1995), Deutsch (2002), Xie (2007), Yu (2007), Wang (2009), and Adeoti (2014) provide comprehensive insights into geological reservoir modelling to understand and development of methodologies, techniques, and models related to reservoir geology. Their work likely covers aspects such as reservoir characterization, simulation, and optimization, advancing the knowledge base in this field. This indicates a well-established foundation in the field. However, the statement also draws attention to a specific gap in research - the lack of studies on modelling a 3D geological model of the H2V formation in the Xiaermen oilfield.

Wang (2009) focuses on the application of 3D computer modelling for detailed reservoir characterization in the Xiaermen Oilfield, China, specifically targeting the H2V deep strata. The authors stress the significance of 3D modelling in improving oil recovery and reducing water cut in reservoirs. The paper concludes by affirming the successful construction of a 3D fine geological model, validated through reserves fitting and aligned with the actual geology of the Xiaermen Oilfield. This model serves as a valuable tool for simulation, analysis, and reservoir management planning.

The study underscores the pivotal role of 3D computer modelling in reservoir characterization, providing a comprehensive overview of the methodology applied in the Xiaermen Oilfield context, where 40 well were used to create a model in this dissertation. This gap suggests a specific and potentially unexplored area within geological reservoir modelling features and reservoir characterization, which could be crucial for a more comprehensive understanding of the subsurface characteristics of the Xiaermen oilfield. Addressing this gap could involve exploring the challenges and opportunities associated with modelling the H2V formation using the specified wells. It may also open avenues for applying and adapting existing reservoir modelling methodologies to this specific geological context. Overall, this observation highlights the continuous need for research to fill gaps and enhance the applicability of geological reservoir modelling to specific geological formations and oilfields.

This current research introduces a novel approach to constructing a 3D geological model of the H2V formation in the Xiaermen oil field, utilizing data from 40 wells to enhance detail and accuracy in model results. The study incorporates information from 25 lithology logs derived from Gamma Ray (GR) and Spontaneous Potential (SP) Logs. In the final stages of the research, the study employs the volumetric value of a reservoir model to calibrate the 3D geological model through reserve fitting. This calibration involves comparing the model's output with geological reserve data, aiming to increase confidence in the accuracy of the constructed model. The calibrated 3D geological model is then positioned for use in future production estimations, highlighting the practical application and significance of the research findings.

Chapter III - CASE STUDY

3.1 Background

3.1.1 Geographic Setting of Xiaermen Oilfield

The Xiaermen Oilfield, is located in Biyang County, Henan Province, is situated in the middle of a large northeast fault edge, to the east of Biyang Sag, Nanxiang Basin (Figure 3. 1).

The Nanxiang Basin, situated between 111000 and 113300E longitude and between 31800 and 33000N latitude, is a small rifted basin that developed in the Mesozoic and Cenozoic Eras (figure 3.1). The basin is filled with dominantly Paleogene age strata, which serve as the main petroleum source and reservoir system.

According to Xie (2007), “Xiaermen oilfield reservoir is structured with branchy anticline in east-west direction having four complicated major faults and many minor faults adjacent to the main oil-bearing area. In some faults, there are small faults to the east which are emerged from the big fault. The extreme trap height is 275 m of the reservoir”.

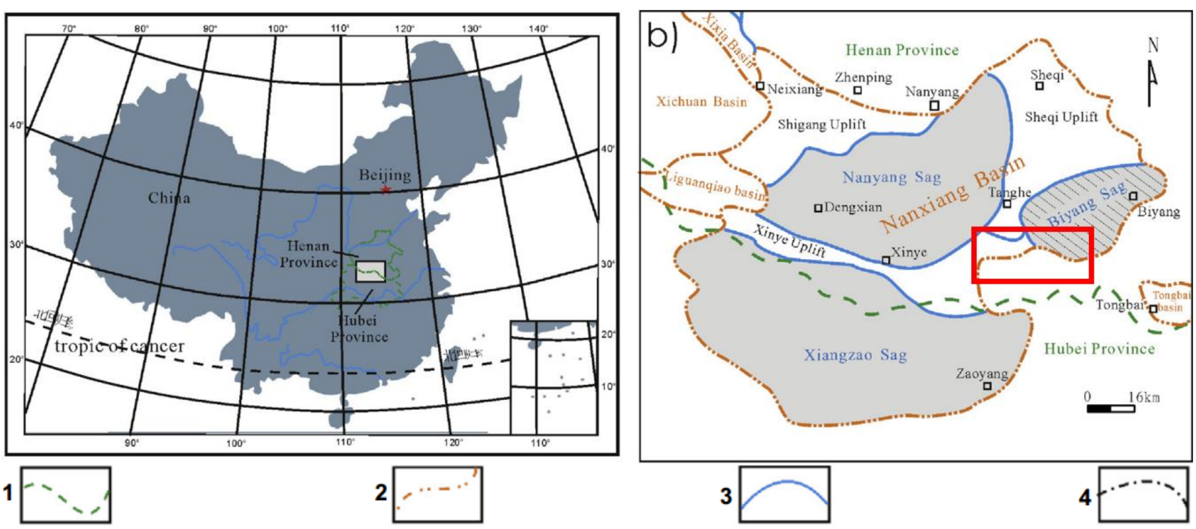


Figure 3.1. Geographic location of Xiaermen OilField (distinguished by red polygon), 1) Province boundary, 2) Basin boundary, 3) Sag boundary and 4) Tectonic zone (Yanlei Dong, et al., 2015).

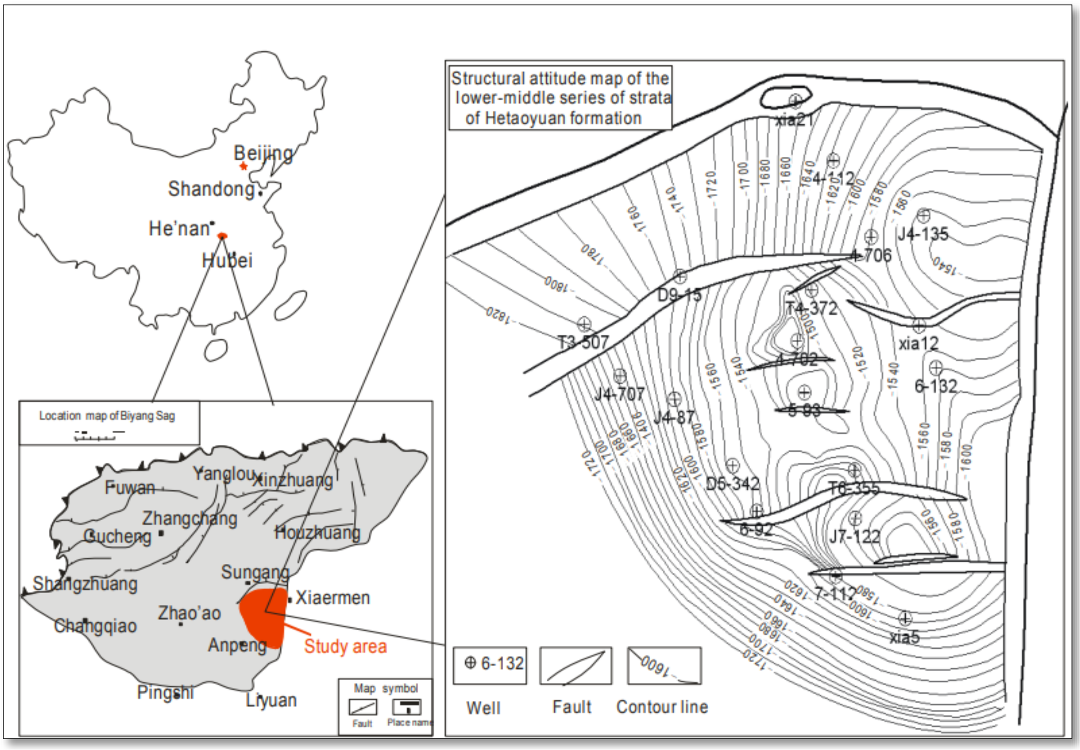


Figure 3. 1: Geographic Setting of Xiaermen Oilfield China (Guan, Z. et al., 2012).

The Xiaermen Reservoir is characterized as unconsolidated sandstone, where its sand was deposited by deltaic fans (HU, 2006). Considerable variation in sand thickness occurring over short lateral distances is characteristic of this particular deposit, and thick layers with high permeability are patchy and isolated. The sediment underlying the project area is fine-grained and relatively clean quartz sand. The average porosity is about 24% and the mean geometric permeability is 2μm^2. The porosity and permeability is generally high, but fairly heterogeneous. Xiaermen Oilfield has an oil-bearing area of 7.5 km^2, oil reserves 2482x10^{4}t, recoverable reserves 924.2×10^{4}t, used reserves 2090×10^{4}t (Guan, Z,2012).

3.2 Geological formations of Xiaermen Oilfield

The Xiaermen Oilfield encompasses four geological formations (H2I, H2II, H2III and H2V). However, the focus of the study is specifically on the H2V formation. This choice highlights a deliberate emphasis on this particular geological formation, suggesting that the available data and research efforts are concentrated on understanding the characteristics, behavior, and reservoir dynamics associated with the H2V formation. The decision to narrow the study to the H2V formation likely stems from its significance in terms of hydrocarbon exploration, production, or specific geological features that make it a key area of interest within the broader Xiaermen Oilfield. Further discussion and analysis are warranted to elaborate on why the H2V formation has been chosen as the primary focus in the study.

3.3 Sedimentary structures of Xiaermen Oilfield reservoir.

These are structures formed during the sediment's deposition (Figure 3. 2). In Xiaermen oilfield sediments such as small trough cross bedding are found under a well named T5-241 at depth of 1352.2m, lenticular bedding is present at depth of 1343.7m in well T5-241, while progressive bedding was found in gas 1 well at the depth of 1162.4m. According to Deng (1998), the dominant lithology is sandstone with 56% quartz, 25.6% feldspar, 18.4% detritus and 6.1% shale in the mineral components. There are obvious high permeability strips and lots of positive microcycles and few negative macrocycles vertically in the reservoir. The formation sandstones are unconsolidated and has large porosity and high permeability, which leads to serious heterogeneity.

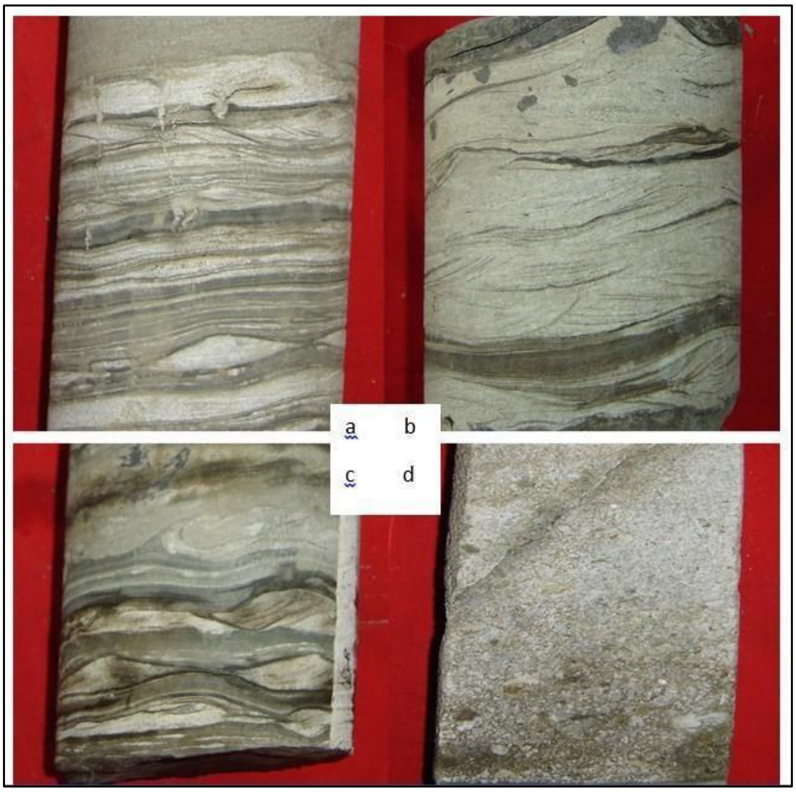


Figure 3. 2: Sedimentary structures and bedding styles, a) and c) lenticular bedding b) and d) progressive bedding.

3.4 Historical Review

Xiaermen oilfield has gone into four stages of production up to 2009 reaching 31 years of production. The production began in September 1978 by exploiting oil from only H2II formation Group Zone, then went to second production development in July 1980 by exploiting oil inclusively in H2III-H2V Oil Group horizon, then in 1981-December it went into further production development improvements by dividing a single Oil Group horizon into three set layers. Then the fourth production development was in 1990, where Xiaermen oil field for the first time went into secondary recovery by water flooding. Different detailed studies were conducted in this Oilfield to solve production problems faced on the reservoir on bases of its recovery efficiency, whereby by the end of year 2013 the water cut was approximately to be around 98% with high decline rate of 24 % (Xie, 2015).

3.5 A case Study of H2V Formation

The H2V formation in the Xiaermen Oilfield is characterized by an oil-bearing area of 1.43 square kilometers and primary geological reserves amounting to 218,000 tons. The oilfield comprises a total of 40 wells, with 36 dedicated to oil production, 4 serving as injection wells, and 6 designed for both injection and production purposes. The well density in this area is calculated at 18.6 wells per square kilometer. The average well spacing in the Xiaermen Oilfield is 235 meters, indicating the distance between individual wells. Notably, the average remaining reserves for a single well are estimated at 10.61 thousand tons, highlighting the potential for continued oil extraction. These parameters collectively contribute to the overall assessment and management of the oil reservoir in the H2V formation within the Xiaermen Oilfield.

Chapter IV - RESEARCH METHODOLOGY

4.1 Introduction

This chapter deals with research approaches, research designs and steps which were used in order to build 3D Model of H2V deep strata formation of Xiaermen oilfield in order to achieve the research objectives (Figure 4. 1). In addition, the chapter describes the study area, methods of data input, algorithm method used to distribute different properties into the 3D geological model. This study was carried out over two steps, where the first step was building up a 3D static geological model of H2V deep strata formation, and the second was the volume calculation which was therefore used to check the validity of the constructed model.

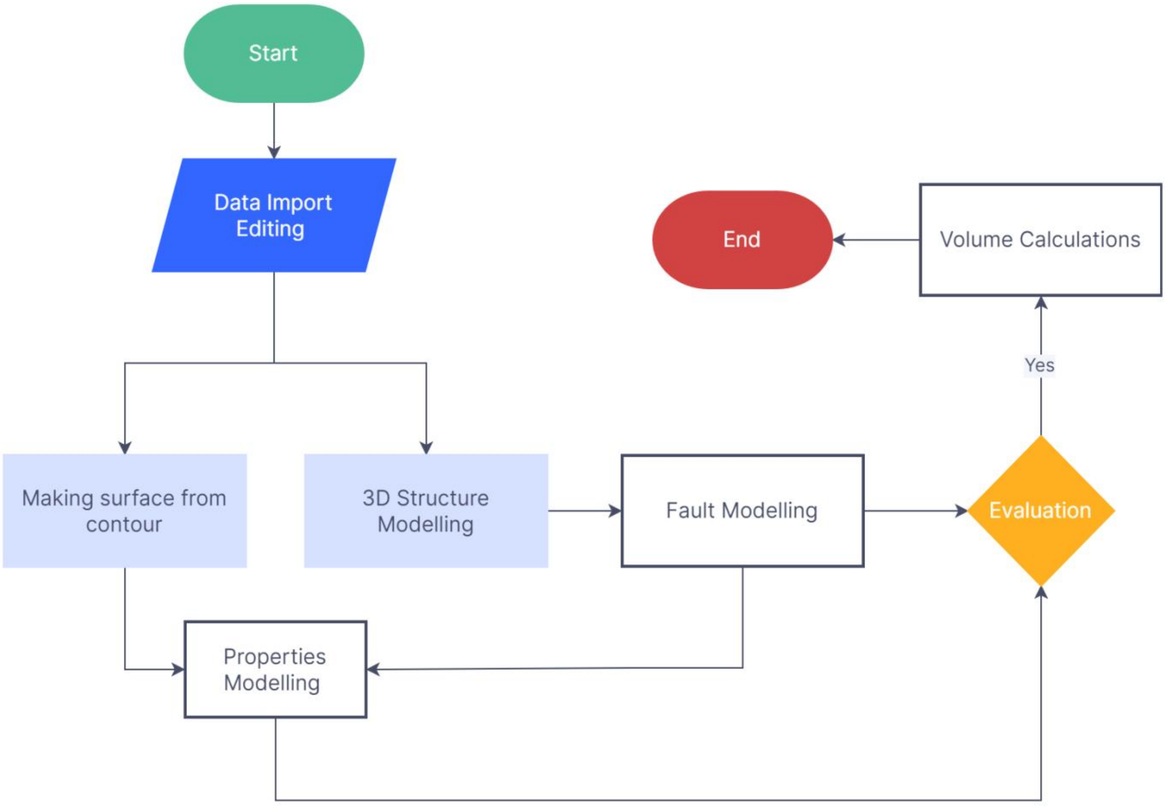


Figure 4. 1: Reservoir Modelling Workflow

Petrel 2013 software, developed by Schlumberger, is a widely utilized application in the oil and gas industry for the construction of 3D geological models. The structure model likely describes the spatial distribution of geological features such as faults and horizons, the facies model represents different sedimentary environments or rock types, and the property model incorporates information about physical properties like porosity and permeability.

The use of Petrel 2013 suggests a comprehensive approach to reservoir modelling, allowing for the integration of diverse datasets and the generation of a holistic representation of the subsurface. Finally, the software was used to calculate the volume of the reservoir, providing essential information for reservoir management and production planning. In conjunction with Petrel 2013, the research involved the utilization of Map Base software to incorporate geospatial data for generating contour lines and polygon data based on a provided geological map. This integration of geospatial information is crucial for various stages, ranging from surface construction to structure modelling in the 3D geological model creation process.

Contour lines, derived from the geological map, play a vital role in surface construction, providing a visual representation of the elevation and structure of the terrain. These contour lines contribute to the accuracy of the structural modelling process within the Petrel software, aiding in the depiction of subsurface features such as faults and horizons. The step-by-step analysis, utilization, and interpretation of geospatial data involved a systematic approach. Beginning with the geological map, the Map Base software was likely employed to extract relevant information and generate contour lines. These lines were then integrated into the Petrel 2013 software for surface construction and subsequent structure modelling.

Moving from structure modelling to property modelling, geospatial data continued to play a crucial role. The interpretation of geological features and properties, facilitated by the combination of Petrel and Map Base, allowed for the transformation of geospatial data into a comprehensive 3D model. This final model, enriched with information from both structural and property perspectives, serves as a valuable tool for reservoir analysis, simulation, and management.

4.2 Research Approach

Quantifying oil in a reservoir model is an iterative process that involves continuous refinement and validation against field data. It requires a multidisciplinary approach, combining geology, reservoir engineering, and simulation techniques to provide accurate estimates of oil reserves and guide effective reservoir management. Qualitative approach was employed, to explore in deep the method used to build a 3D geological model using well data, and to determine the initial hydrocarbons in place of a reservoir and compare it with the primary geological reserve, to check quality and validate the created model. This step ensures that the model accurately reflects the observed reservoir behaviour and involves assessing the amount of oil, gas, and other hydrocarbons that can be economically produced from the reservoir.

a) Theoretical Approach

A 3D geological model of H2V model of Xiaermen oilfield was constructed using a sequential approach work flow, where large scale properties (discrete value) were modelled first, then followed by smaller ones or property data with many uncertainties under geostatistical modelling, to see its distribution.

b) Geostatistical Modelling

Geostatistical modelling is a powerful framework for analyzing and modelling spatial data, offering insights into the spatial structure and variability of geological and environmental phenomena. This methodology is particularly useful in the characterization of natural phenomena that vary across space, such as geological features, environmental variables, or resource distributions.

Geostatistical modelling plays a crucial role in linking the stratigraphic geometry and stratigraphy of a reservoir interval (Figure 4. 2). In the modelling process, a conceptual model is developed, serving as a foundational framework for understanding the architecture and continuity of facies, as well as petrophysical properties. In the context of reservoir modelling, facies serve as a proxy for different rock characteristics, and their spatial distribution influences the heterogeneity of petrophysical properties such as porosity and permeability. By employing cell-based techniques, each cell in the model is assigned a specific facies, capturing the spatial variability of rock types within the reservoir. Modelling facies before petrophysical properties introduces a controlled variation in the distribution of these properties. This allows for a more realistic representation of the subsurface, capturing the complexities of rock types and their associated physical characteristics. This is particularly relevant for accurate reservoir characterization and the optimization of resource recovery strategies. Porosity and permeability within the reservoir formation (Pyrcz, 2014). The conceptual model is a key step in the geostatistical modelling process, providing a systematic representation of the subsurface characteristics.

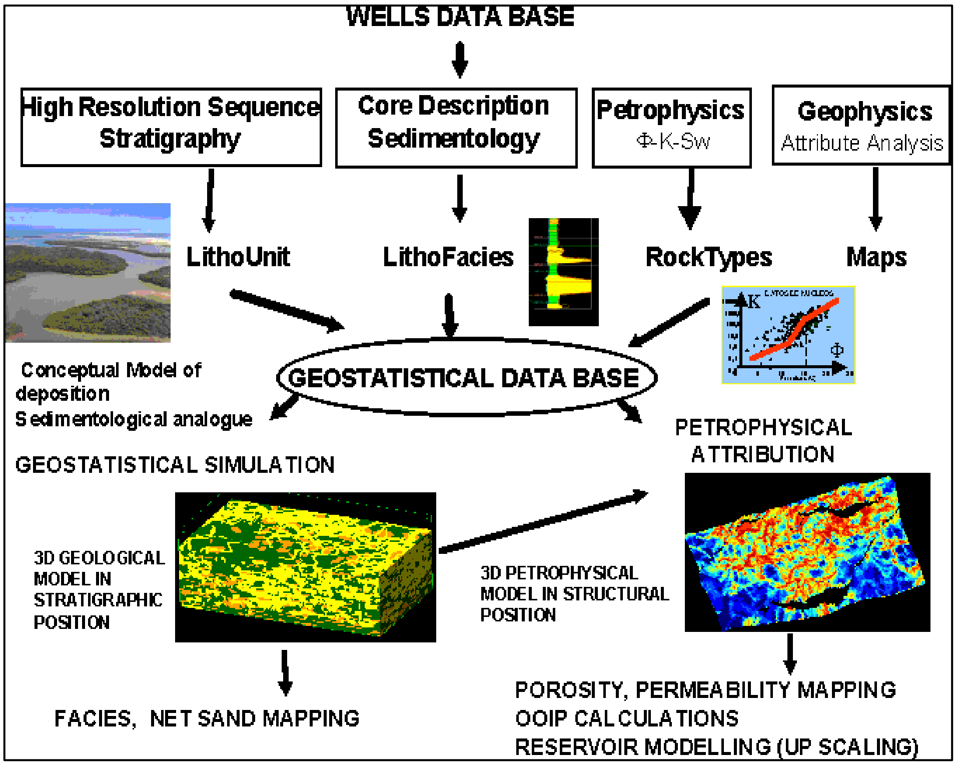


Figure 4. 2: Workflow in geostatistical modelling.

In the context of reservoir modelling, facies serve as a proxy for different rock characteristics, and their spatial distribution influences the heterogeneity of petrophysical properties such as porosity and permeability. By employing cell-based techniques, each cell in the model is assigned a specific facies, capturing the spatial variability of rock types within the reservoir.

Modelling facies before petrophysical properties introduces a controlled variation in the distribution of these properties. This allows for a more realistic representation of the subsurface, capturing the complexities of rock types and their associated physical characteristics. This is particularly relevant for accurate reservoir characterization and the optimization of resource recovery strategies.

Porosity model, was built following or based on the flow of facies rock type, this is modelled first before permeability because it can be used as a secondary input bias when modelling permeability as well as have more data of porosity.

The Permeability model is constrained to the porosity, facies, and layering previously established. At times, there may be a conflict between the facies and porosity already established and well test or production-derived permeability data. In this case, such permeability data should be expressed as constraints on the porosity and permeability models and used in steps 2 and 3 above.

Multiple likewise realizations are made via repeating the whole process. Every realization is “equally probable to be drawn” though, some realizations are nearly similar to one another.

4.3 Modelling Methods

Modelling constitutes a major choose of this approach is examined under systems' tract changes where systems tract refers as a nature of sedimentation or particular form, where most reservoir are in a single system tract, for example, fluvial deltaic, shore face systems or deep-water depositional systems (Deutsch, 2002) geological system tract may change across the area extension of the model. Such as fluvial and related terrestrial facies give a way to deltaic and other marine facies. For such large-scale changes in facies must be accounted for, facies modelling, regardless of whether cell-or object-based modelling is used. There are two common simulation methods used to build a reservoir model: Sequential Gaussian simulation was used to create a model based on continuous variables such as porosity and permeability and Sequential indicator simulation was used to create a model based on categorical variables like facies.

4.4 Import well data

The well data available for the H2V deep strata formation, as detailed in Table 4. 1, were obtained from the China Library through a collaborative effort with the University of China. This collaborative initiative suggests a partnership between the university and the library to access and utilize pertinent well data for the H2V formation, specific details about the available well data, including parameters such as well location, depth, lithology, and petrophysical properties. The China Library is a reputable source, indicating that the data has been curated and maintained with a high standard of reliability. This data are visualized in the Figure 4.3, represented as combination of wellhead, well top, and well deviation.

Table 4. 1: Well Data.

	Descriptions	Numbers of well	Total
Well Head	Production	30	40
	Injection	10	
Well Logs Data	Porosity	22	78
	Permeability	16	
	Saturation of water	15	
	Lithology	25	
Well Tops	-	32	32
Well Deviation	Oil Well	30	40
	Water Well	10	

The wellheads are likely marked or represented as points on the graphic of figure 4. 3, indicating their spatial distribution in the study area. Each wellhead is associated with information such as its geographical location, depth, and other relevant data. The well tops, which typically refer to the uppermost points or markers in each well bore, are likely visualized alongside the wellheads.

This information is crucial for understanding the stratigraphy and geological characteristics at different depths within the wells. The contour lines on the right side of the display provide a visual representation of the variation in a specific parameter across the study area. Contour lines connect points of equal value, and their spacing or configuration can convey information about the underlying geological features, such as elevation, thickness of a geological layer, or a specific petrophysical property (figure 4. 3).

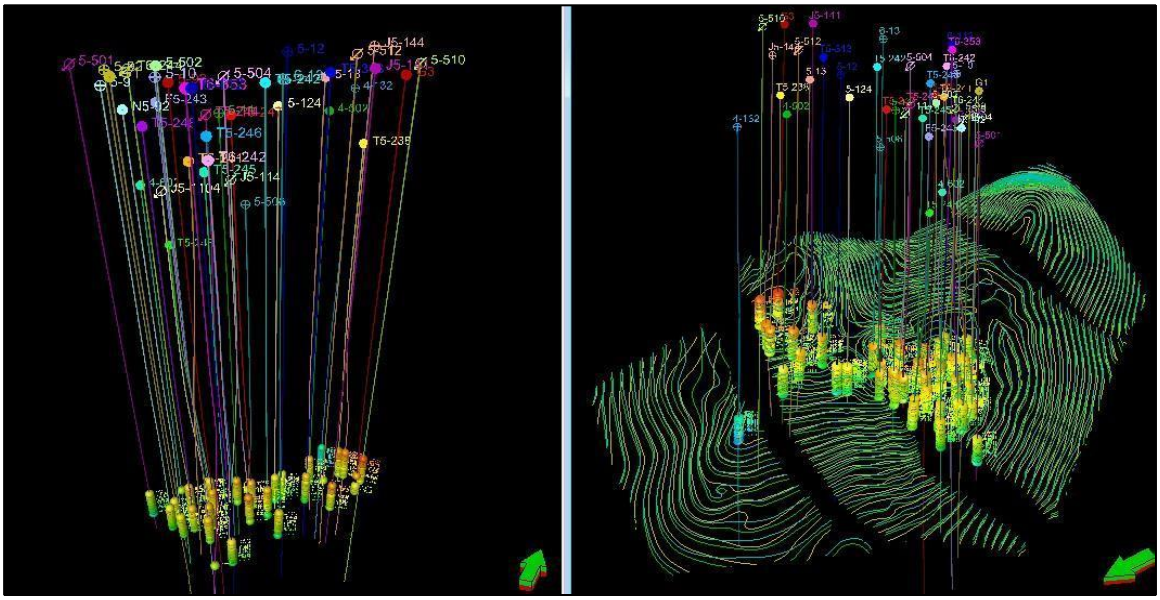


Figure 4. 3: Graphical representation displays 40 imported wellheads along with their respective well tops. On the right side of the illustration, contour lines are depicted.

4.5 Well correlation and well log

Well correlation create a coherent stratigraphic framework for the subsurface process of comparing and establishing relationships between geological formations encountered in different wells has a is crucial for understanding the lateral continuity of geological formations, identifying depositional environments, and constructing an accurate geological model encountered in different wells, represented (Figure 4. 4). Furthermore, it aids in mapping the extent of reservoirs and predicting the distribution of rock types, identifying hydrocarbon zones, assessing reservoir quality, determining fluid types, and estimating key parameters for reservoir engineering, such as porosity and permeability. Subsurface. It aids in mapping the extent of reservoirs and predicting the distribution of rock types, identifying hydrocarbon zones, assessing reservoir quality, determining fluid types, and estimating key parameters for reservoir engineering, such as porosity and permeability. The depiction includes identification of the deposition layer and the region of interest, providing insights into lithology’s and stratigraphic characteristics.

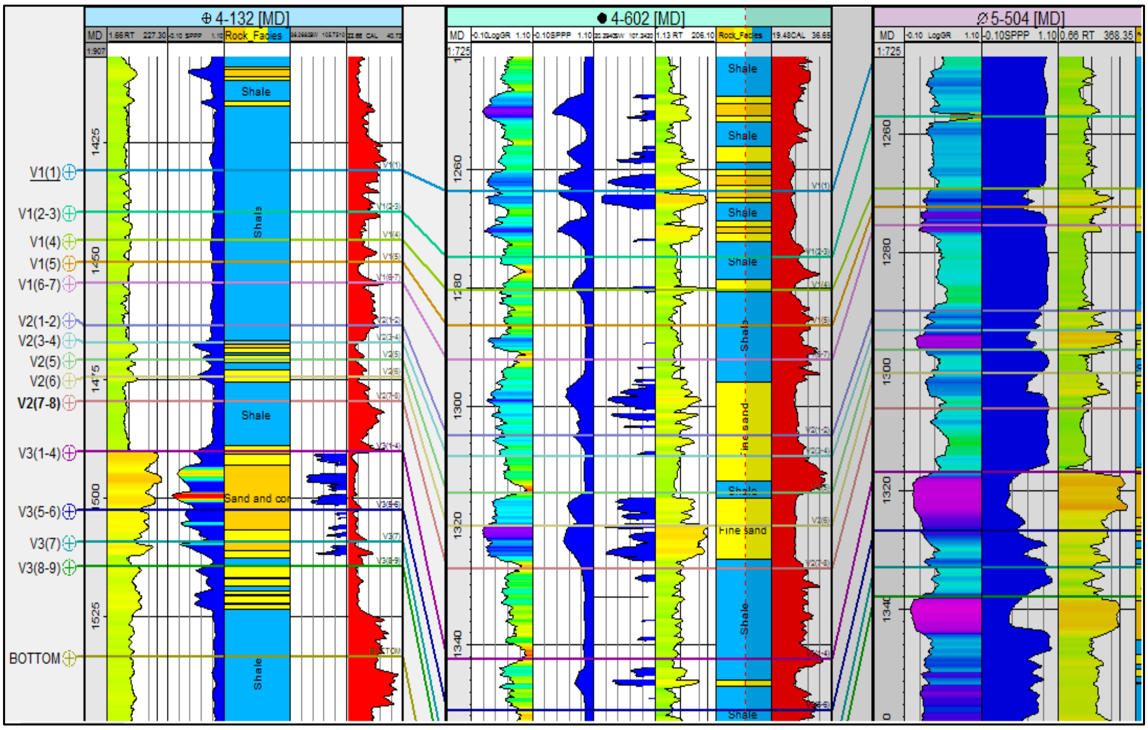


Figure 4. 4: Well correlation and well log information for the H2V formation in the Xiaermen oilfield.

4.6 Surface contour lines and well tops

A surface of 3D Model for H2V Formation was created from contour data (soft data) and, well top (hard data), using a method called Convergent interpolation (Figure 4. 5). Main input data was contour to set in a boundary specified; well adjustment data was from a designated well top. The reason why both contour and well top were used is to validate the model data using both hard and soft data.

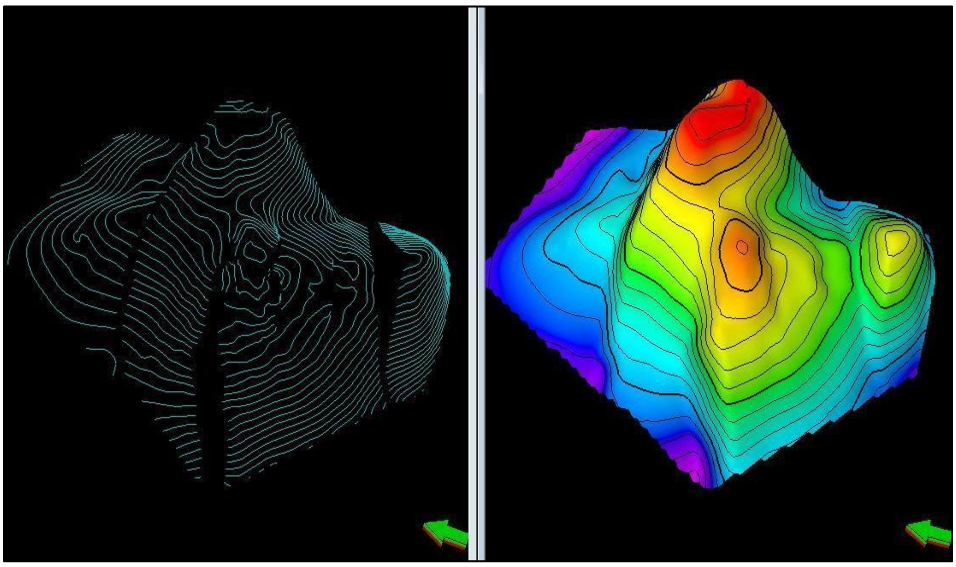


Figure 4. 5: Integrates the visual representation of a surface using contour lines.

Additional information or an account specifically related to elevation (Figure 4. 6). This combination provides a comprehensive depiction of the terrain, allowing for both a visual interpretation and a quantitative understanding of the elevation variations across the depicted area.

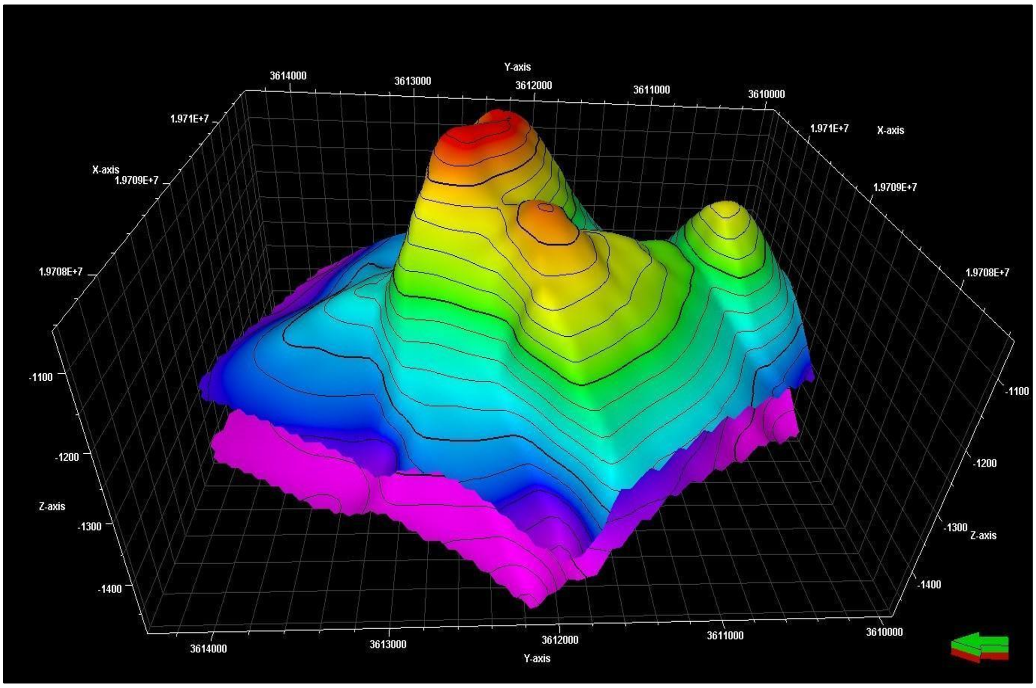


Figure 4. 6: The visual representation of the top and bottom surfaces in a 3D display of the H2V Formation, offering insights into the spatial characteristics and structure of this geological unit.

4.7 Structure modelling

Structural modelling is a crucial aspect of building a reservoir model, as it encompasses the entire framework of reservoir architecture. In this section, various steps are followed to complete the structural modelling process. Specifically, under the Petrel software, structural modelling is categorized into five stages. These stages involve a systematic approach to capturing and representing the structural characteristics of the subsurface reservoir.

Stage 1: Fault Modelling

During the fault modelling process Main and Minor faults were identified, Figure 4. 7, the H2V formation, four main faults and many minor faults, from which three minor faults were included in a model, together Main and minor faults were identified and modelled. Major faults are the ones which shows a wider range limit/coverage of reservoir blocks, while Minor faults are the ones which vary in a very short distance some of the minor faults have negligible effect on the global geometric of the modelled reservoir.

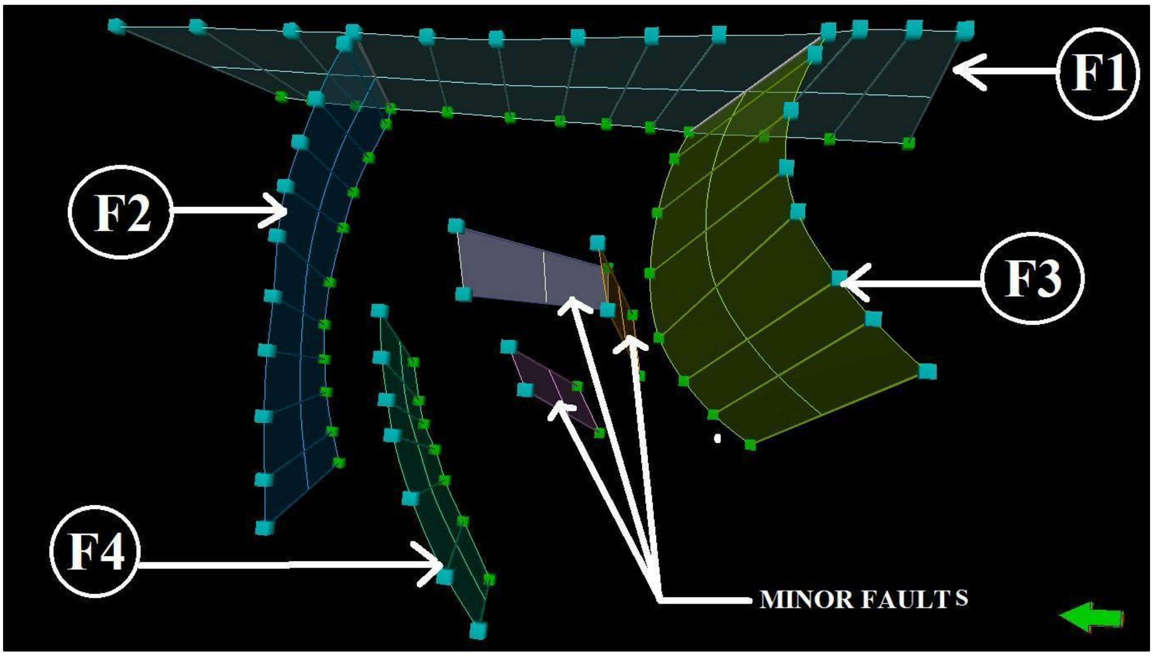


Figure 4. 7: Fault modelling, Main faults labelled F1 (North to south), F2 (West t- east attached to major fault F1), and F4 and F3 aligned from West - East direction attached to the F1 Fault, and minor fault.

Stage 2: Pillar Gridding

Pillar gridding is used to define the horizontal scale of the reservoir surfaces (top, mid and bottom surface). Grid were generated from modelled fault model of H2V formation reservoir, Figure 4. 8. The setting for grid distance in I and J direction was set into 22 meters in I direction and 22 meters in J direction, this was considering well space distance as well as to have grids in between one well to another. In H2V deep strata formation the average well spacing is 235 m, hence according to the set grid value there is almost 12 grid cells from one well to another.

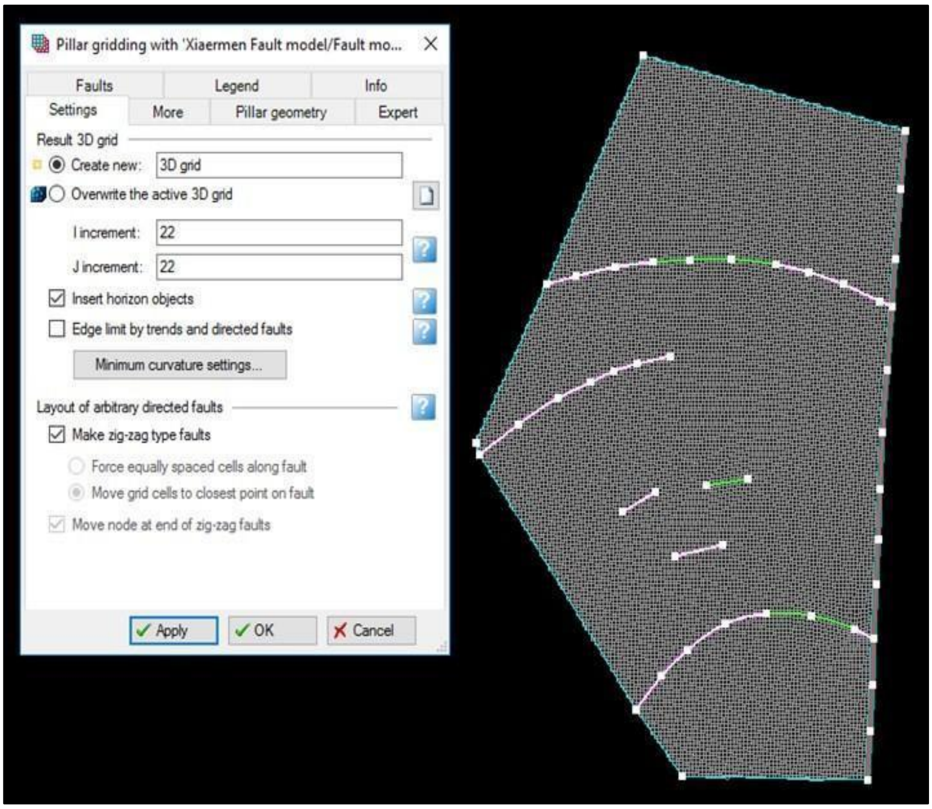


Figure 4. 8: 2D display of a grid together with faults.

Stage 3: Mapping Horizons

The primary objective of this procedure was to establish the vertical measurements within the geological model. The process was constructed using surfaces, with a total of 15 surfaces delineating the reservoir from top to bottom. In this phase, the offset on the faults was defined. The outcomes of this process are visually represented in Figure 4. 9. This approach serves to define the vertical aspects of the geological model, allowing for a detailed understanding of the subsurface structure. The utilization of surfaces and the incorporation of fault offset considerations contribute to the accurate representation of the reservoir's stratigraphic complexity. The creation of horizons from specific surfaces further refines the model, enhancing its precision and reliability and presented to offer a visual insight into the outcomes of this phase of the modelling process. This representation aids in visualizing the spatial relationships between geological features, understanding the topography, and refining the characterization of subsurface structures.

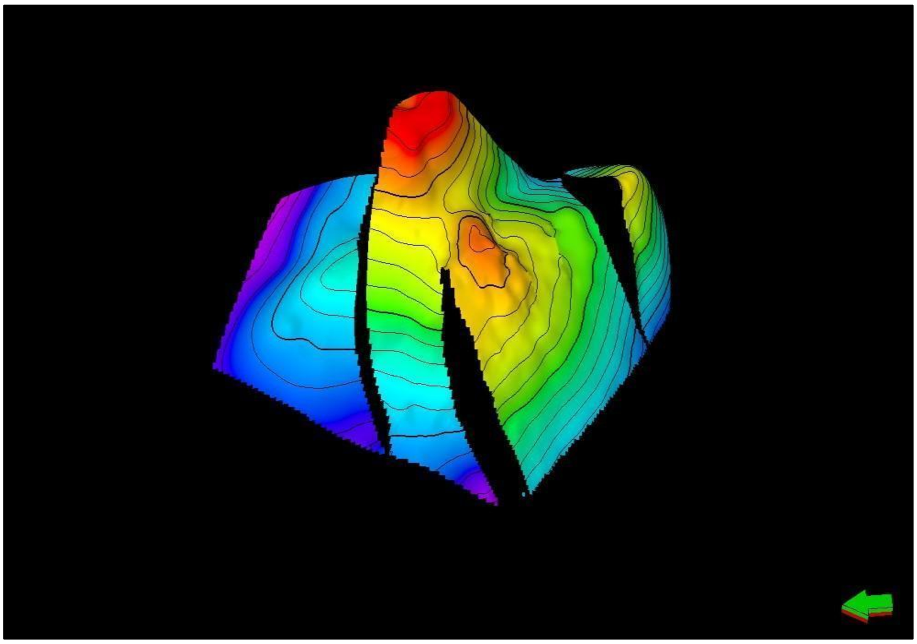


Figure 4. 9: Horizon from surface and the effect of faults model onto the 3D grid, where faults show breaks on the resulting horizon from surface.

Stage 4: Zones and Layering

The process of establishing zones was grounded in the calculation of stratigraphic intervals. Zones were delineated from the top horizon through the vertical thickness to the bottom horizon. The input data used for this procedure consisted of conformable well tops. Each horizon sets the constraints or boundaries for a specific stratigraphic unit or interval. The software calculates the interval both above and below the top and base horizons, respectively, as illustrated in Figure 4.10, which involves systematically defining geological zones based on the stratigraphic intervals determined by the well top data. Each horizon acts as a reference point, helping in the precise identification of stratigraphic units within the subsurface. The resulting zones provide a structured framework for characterizing and analyzing the geological composition of the reservoir. Figures 4. 11 visually represent the outcome of this process, showcasing the stratigraphic intervals and the corresponding zones delineated by the software. Layering stage involves inserting and generating fine scale grid cells, which are essential for interpreting vertical variation in every geological zone.

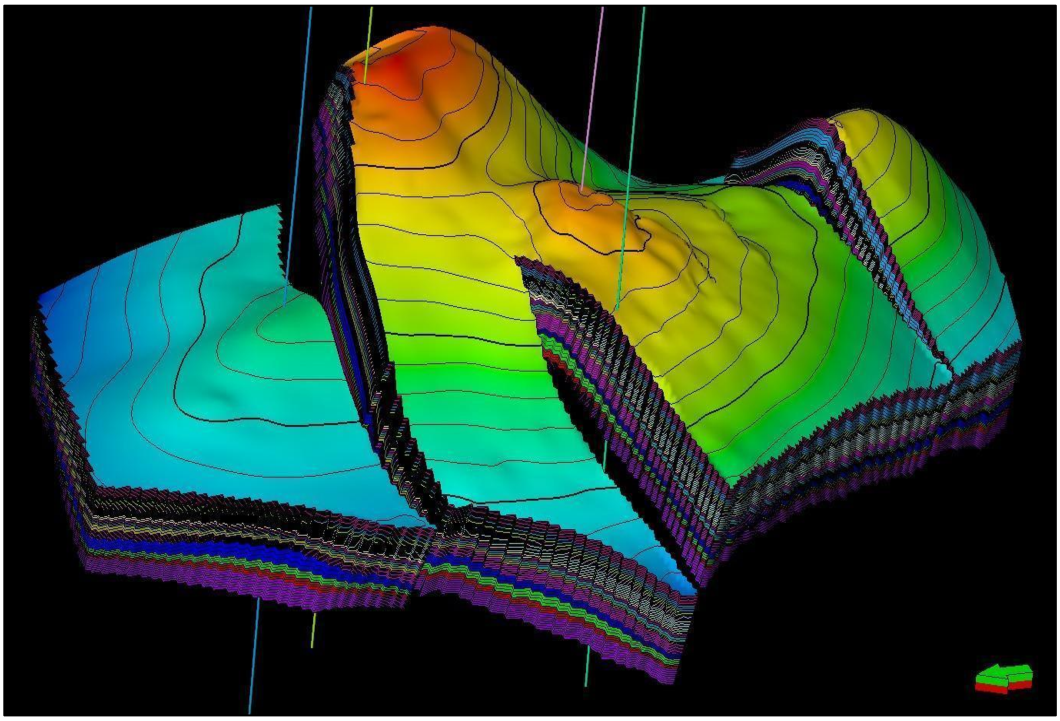


Figure 4. 10: Zones for H2V and Layering

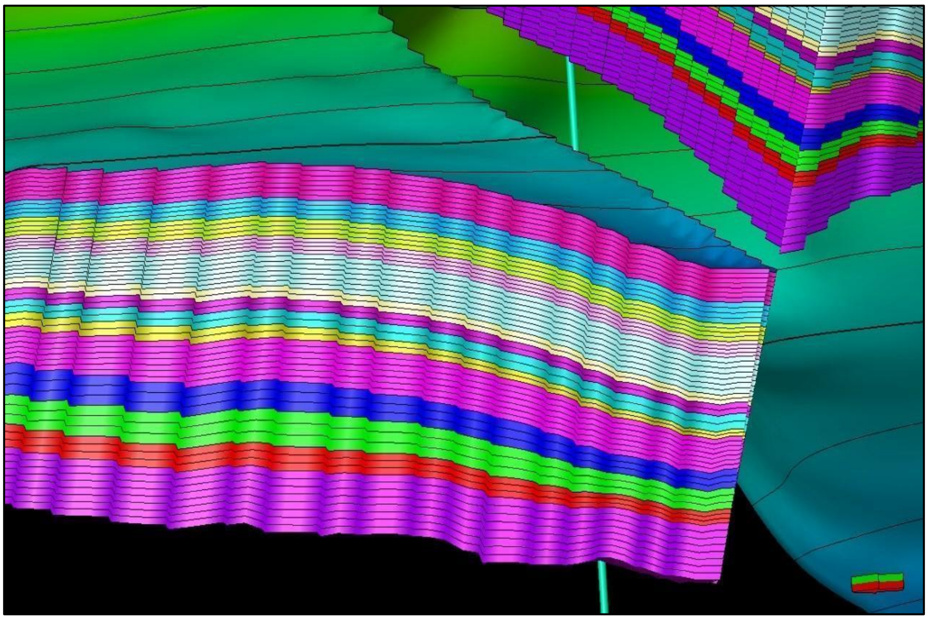


Figure 4. 11: Illustrates the creation of 58 layers derived from 14 zones.

Where the division into zones allows for a detailed representation of the geological heterogeneity. The creation of numerous layers within each zone enables a more nuanced understanding of the stratigraphy and composition of the subsurface. This process is essential for accurate reservoir characterization and effective decision-making in the context of hydrocarbon exploration and production.

4.8 Properties modelling

The Properties modelling is to allow the distribution of properties for the available wells' data, the process involves showing how the well data are matching to each other as well as heterogeneity of the reservoir (Figure 4. 12).

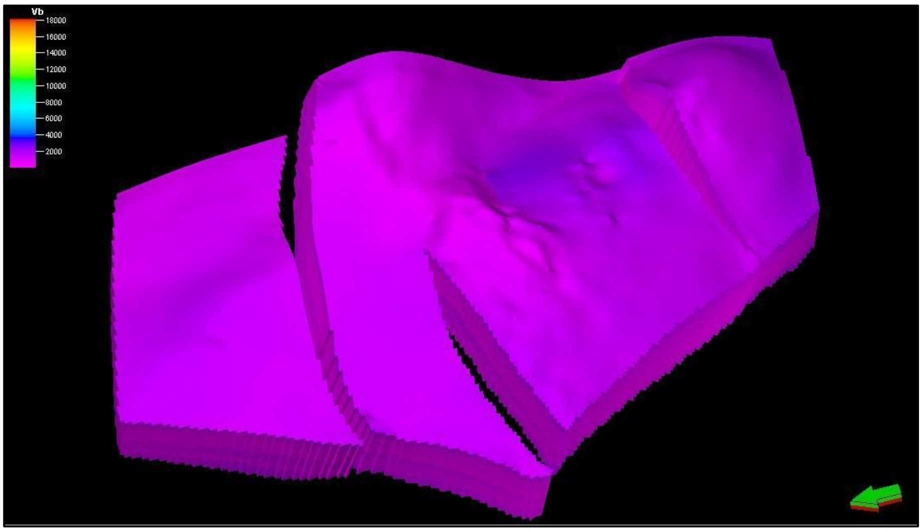


Figure 4. 12: Representation of 3D Bulk volume model of the structure model.

Table 4. 2: Statistics for Bulk volume.

Statistics for Bulk Volume		
Axis	**Min**	**Max**
X	19707677.36	19710633.25
Y	3609925.09	3614345.84
Z	-1485.1	-1048.65
Bulk volume	6	

In order to model the properties, three main steps were followed:

i. Scale up well logs, the available well data scaled up, in order to distribute the available well data to the nearby grid cell where the well penetrates, but for the distant cells property modelling was done to show the distribution of a specific property to the whole reservoir grid cell.

ii. Data analysis under the modelling process, variogram were set according to the modelled property. Data analysis process is essentially used to check up and interpret based on their similarities and flow trend of the given well logs.

iii. Specific property modelling process. For that, input distribution of the data is honored during the modelling process, the output data were interpreted on how much their variation was distributed.

Basically, data trends are identified in the data analysis process then, used in property modelling processes to model the random variation away from that trend. In this process it is important to decide whether the trend is real or not, if the trend is not genuine, it must be ignored.

a) Variogram in modelling

Under property modelling, a variogram was employed to articulate variations in property values. The variogram captures the relationship between data points, indicating that points in proximity are more likely to have similar values than those farther apart. Two key aspects define a variogram: The nugget represents the value that quantifies how similar nearby data values are. In other words, it reflects the degree of spatial correlation among data points in proximity. A smaller nugget suggests a high degree of similarity between closely located data points. The range is the value used to determine how far points must be from each other before they no longer exhibit a significant relationship. It defines the distance beyond which data points become independent and do not influence each other's values. A larger range indicates a more extensive spatial correlation, where points need to be farther apart to be considered unrelated.

In essence, the variogram analysis provides insights into the spatial continuity and correlation of property values across the studied area. By understanding the nugget and range parameters, practitioners can fine-tune the property model to accurately represent the spatial variations of the studied property. This process is particularly crucial in geostatistics and reservoir modelling, contributing to more reliable predictions of subsurface characteristics.

4.9 Facies modelling

Facies refers to the body of sedimentary rock with specified characteristics, including lithology (lithofacies) or fossils (biofacies). The analysis of Sedimentary Facies relies on the concept that facies transitions commonly occur more than expected. The importance of facies analysis, as well as sequence stratigraphy, is on their applicability to predict facies distribution from one point to another (between wells). According to (Blick, 1995) the Sequence stratigraphy is very widely used as a tool in the oil and gas industry for predicting the spatial distribution of lithofacies. It has proven to offer great value as a 'unifying framework' for analyzing and interpreting sedimentological facies, lithostratigraphy and chronostratigraphic data. Conceptual facies model was also used during facies modelling, it was used to compare the resulting facies model of lithology flow to the conceptual model to verify the validity of the modelled model. Using these tools, we can assess the uncertainty in the models, the unknown that inevitably results from never having enough data. Begin with facies model during modelling process, because facies are used to assess geological variables such as grain size, lithology and rock type. Facies gives a narrow range to the respective properties, since their variation with facies is proportional.

Three different lithologies were defined and identified from SP and GR logs using an alpha mapping method formula. Alpha mapping method is used to identify lithology in the classic succession by SP curves according to (Dresser, 1974).

1. SSP for net sandstone and baseline of shale will be determined in the well column.
2. Alpha value was calculated using the equation below description

$$\propto = \frac{PSP}{SSP} = \frac{SP - SP_{min}}{SP_{max} - SP_{min}}$$

The cut-off value to distinguish sand and conglomerate, fine sandstone and shale was set according to the analysis of well site geological data. Afterward, Lithology logs were scaled up, then data analysis were conducted using variogram. Sequential indicator simulation method was used to distribute data throughout the structure model. Where for $\propto$, > 0.75: $Sand \wedge conglomerate$ $0.5 - 0.75$: $Fine\ sandstone < 0.5$: $Shale$.

a) Scale up well logs

"Scale up well logs" generally refers to the procedure of augmenting the size or resolution of well logs within the realm of geological or reservoir studies. This process entails improving the level of detail or extending the coverage of data acquired through well logging activities. The purpose of scaling up well logs is typically to offer a more thorough and precise depiction of subsurface geological formations or reservoir attributes. The aim is to enhance the accuracy and dependability of data, facilitating more effective analysis and interpretation in fields such as geology, petroleum engineering, or related disciplines. Well log data of lithology were scaled up and the results of the scaled-up logs are presented in a Figure 4. 13: Facies well logs and upscale log graph, represented for code 0: represents sand and conglomerate 15.9% upscaled to 18.0%, code 1: fine sand with 28.8% upscaled to 31.1%, and code 2: Shale logs 55.3% upscaled to 50.8%.

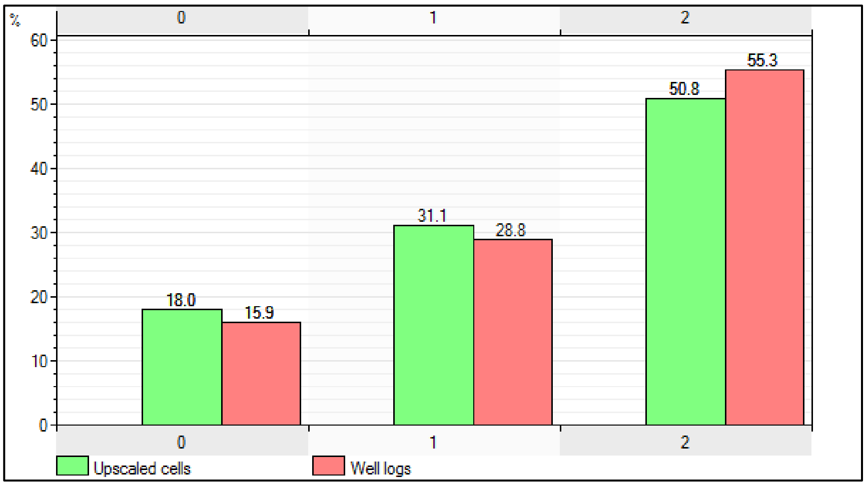


Figure 4. 13: Facies well logs and upscale log graph, represented for code 0.

b) Data analysis (Variogram analysis)

Data analysis, specifically Variogram analysis, was conducted in different directions to understand the variation trend of facies modelling data. a) Vertical direction in Figure 4. 14, the variation trend of facies modelling data in the vertical direction is illustrated. The trend shows a good fit to the graph, benefiting from the abundance of well data in the vertical direction. The availability of ample data in this direction contributes to a well-fitted trend, providing valuable insights into the vertical distribution of facies characteristics. b) Minor direction - the variation trend of facies modelling data in the minor direction is presented in the figure below. However, the trend fitting in the graph was not as satisfactory when compared to the vertical direction. This discrepancy is attributed to the relatively limited amount of well data available in the minor direction, impacting the precision of the trend analysis. These observations underscore the importance of data density and distribution in accurately capturing the trends in facies modelling.

a)

b)

c)

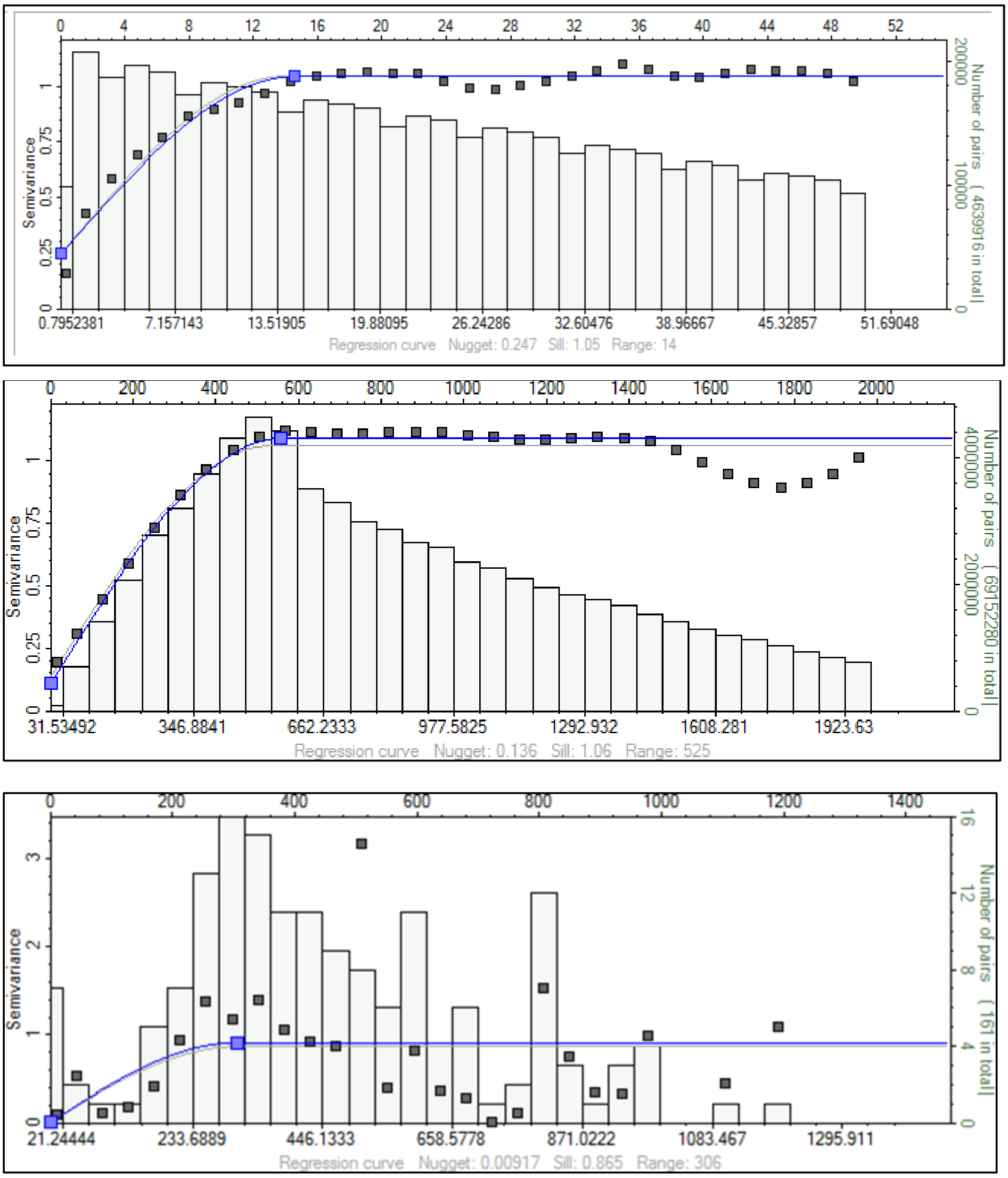


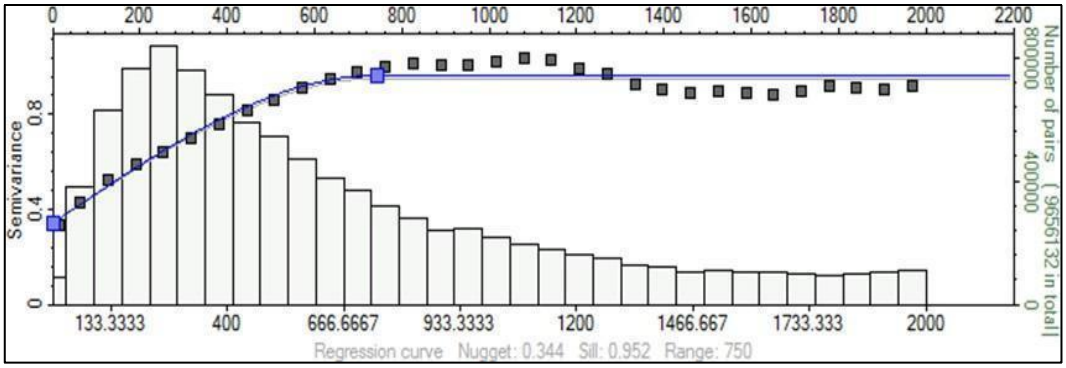
Figure 4. 14: Trend of facies.

Adequate data, especially in less-sampled directions, is crucial for a comprehensive understanding of the spatial variability of facies characteristics. c) Major direction - illustrates the variation trend of facies modelling data in the major direction. However, the trend fitting in the graph was not satisfactory when compared to the vertical direction. This discrepancy is primarily attributed to the limited availability of well data in the major direction. The challenge in achieving a well-fitted trend in the major direction underscores the importance of having a robust dataset. The scarcity of well data in this direction may introduce uncertainties and impact the precision of the facies modelling analysis. It highlights the need for additional data collection or alternative modelling approaches to improve the reliability of insights gained from the major direction.

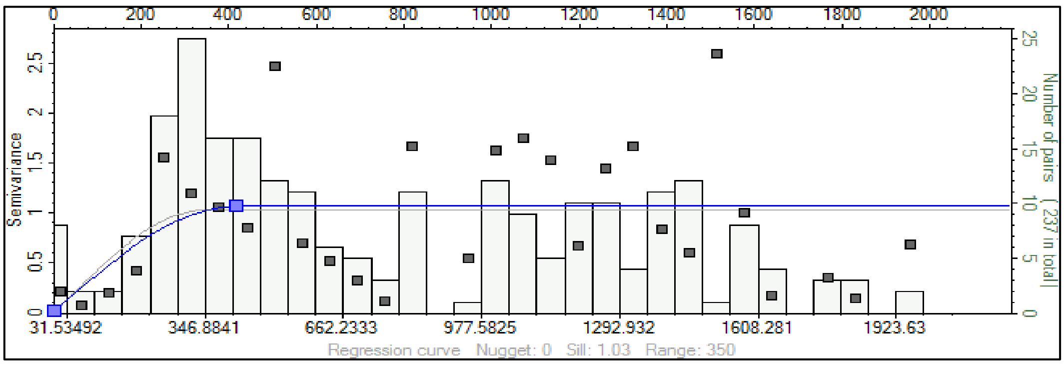
4.10 Porosity Modelling

The observed trend in the porosity modelling data, represented in Figure 4. 15, in a) minor, b) major and c) vertical direction. Shows a strong alignment with the graph in the vertical direction linked to the abundance of well data accessible along the vertical axis, facilitating a thorough comprehension of porosity variations in the vertical orientation. The well-fitted trend in the vertical direction enhances the accuracy of porosity modelling, offering valuable insights into the subsurface characteristics specific to this orientation.

a)



b)



c)

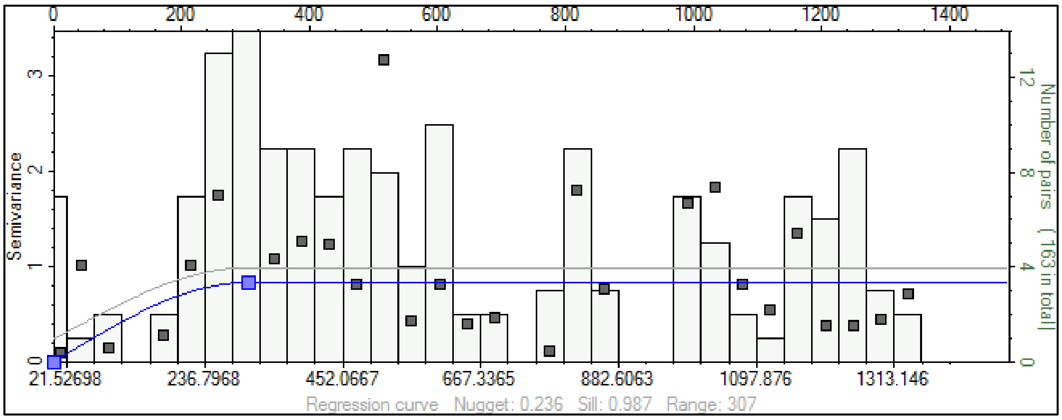


Figure 4. 15: Porosity variogram modelling.

According to (Webber, 1990) means a capacity of reservoir rocks to accommodate fluids. High porosity values indicate high capacities of the reservoir rocks to contain these fluids, while low porosity values indicate the opposite. Consequently, porosity data are routinely used qualitatively and quantitatively to assess and estimate the potential volume of hydrocarbons contained in a reservoir.

Table 4. 3: Qualitative evaluation of porosity.

Qualitative Evaluation	Porosity (%)
Negligible porosity	0–5 %
Poor porosity	5–10 %
Fair porosity	10–15 %
Good porosity	15–20 %
Very good porosity	20–25 %

4.11 Permeability Modelling

The variation trend of permeability for modelling data in major direction, is fitting in the graph, was compared to vertical direction since there was few well data. Results of the variogram Figure 4 .16, where major range that presented results varying from for the major direction, (b) minor and (c) vertical range.

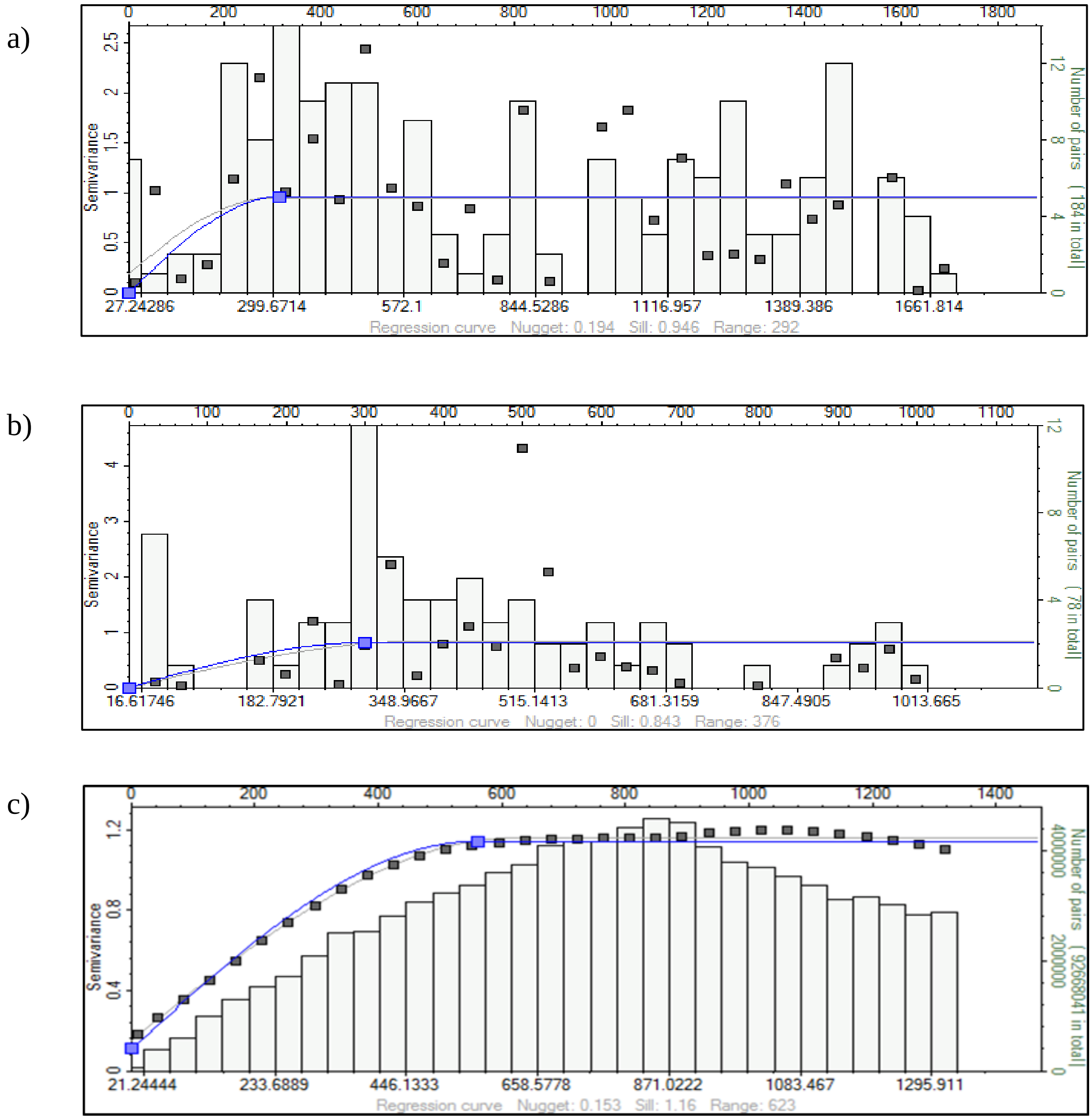


Figure 4. 16: Permeability variogram modelling

As per Levorsen (1967), the permeability of a reservoir can be classified into four categories, Table 4. 4. The permeability range is divided into distinct categories to determine the reservoir's significance. Below are the four permeability categories with their respective ranges:

1) Low Permeability - This category typically includes reservoirs with permeability values in the lower range. These reservoirs may exhibit limited fluid flow characteristics;

2) Moderate Permeability - Reservoirs falling within this category possess permeability values that are moderate, indicating a moderate capacity for

fluid flow;

3) High Permeability - Reservoirs in this category have permeability values in the higher range, signifying a substantial capacity for fluid flow;

4) Very High Permeability - This category comprises reservoirs with permeability values in the very high range, indicating an exceptional capacity for fluid flow.

The classification into these permeability categories assists in evaluating the reservoir's characteristics and plays a role in reservoir management, production planning, and overall understanding of subsurface fluid dynamics.

Table 4. 4: Permeability qualitative evaluation (Levorsen, 1967).

Average K-value (MD)	**Quantitative Description**
Fair	1 < k < 10 md
Good	10 < k < 100 md
Very good	100 < k < 1000 md
Excellent	1000 md

4.12 Oil water contact model

The Water Oil Contact was established using resistivity logs to distinguish between the water zone and the hydrocarbon zone. The depth of this contact varied depending on the specific well location, as illustrated in Figure 4. 17 and Figure 4. 18. These figures visually demonstrate the differences in the depth of the Water Oil Contact across various well locations, providing valuable insights into the subsurface characteristics and aiding in the delineation of hydrocarbon-bearing zones within the reservoir.

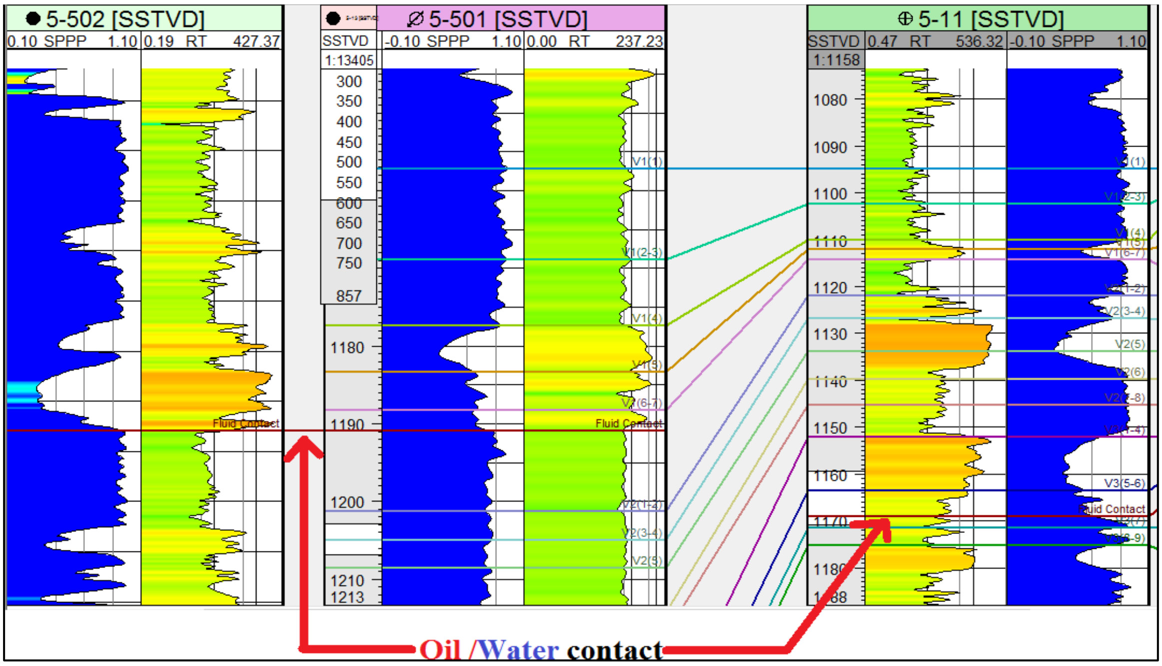


Figure 4. 17: Oil/Water contact from RT logs.

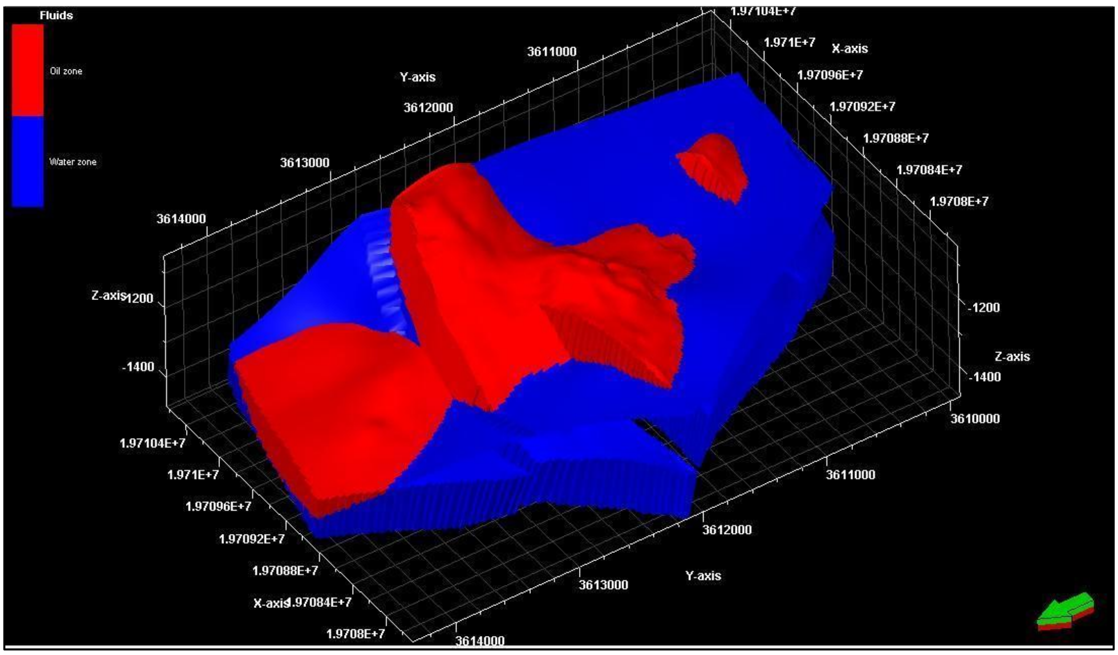


Figure 4. 18: Oil and water zone in H2V reservoir formation.

4.13 Volumetric Method

Volumetric method is the techniques most used for reserve estimation. It was used to estimate a recoverable volume from, porosity, oil saturation, and recovery efficiency. The reserve estimates are obtained using simple volumetric relation

$$Reserve = V \times \varphi \times S_0 \times B_0 \times RecoveryFactor$$

Where, V reservoir volume, φ average porosity, S_0 average oil saturation, and B_0 is oil formation volume factor. Porosity and saturation are estimated from well log. Recovery factor is also uncertain and obtained based on rock and fluid properties, (Tarek A, 2011).

Chapter V - RESULTS AND DISCUSSION

5.1 Introduction

This chapter covers the research findings, results and discussion of the modelled 3D geological model of different petrophysical model such as facies/lithology, porosity, permeability, and water saturation model as well as a discussion on calculated volume of oil of the H2V formation reservoir.

5.2 Results and Interpretation

a) Structural model of H2V formation of Xiaermen Oilfield

The structural model gives clarification of fault and horizons from top to bottom of the H2V reservoir structure. The model was built with grid size of 22m x 22m in I and J directions in every cell, total cell number is 122 x 198, the structure model have 15 iconized horizons, later divided into 58 layers. In the structural model, also it indicates the fault's orientation in a model, where there are major four faults, while the remaining faults were categorized as minor faults.

Table 5. 1: Statistics for Horizons.

Axis	Min	Max	Delta
X	19707677.36	19710633.25	2955.89
Y	3609925.09	3614345.84	4420.74
Z	-1485.1	-1048.65	436.45
Number of iconized horizons:	15		
Cells (nI x nJ)	122 x 198		
Total number of 2D nodes:	24477		
Total number of 2D cells:	24156		

The structure model where ready to be used for property modelling where properties such as facies, porosity, permeability and water saturation were distributed in every cell. According to the research methodology used to construct the model, discrete properties were modelled first followed by other petro-physical properties.

5.3 Properties Modelling Results

Distribution of properties to the entire part of the model is one of the aims of building a 3D model. This helps to show how often the properties are distributed to the entire model leading to a better decision-making on to place new wells for field development, it will also help to solve different production problems encountered in individual oil fields. The following are the properties modelled in H2V formation, which show how property data were distributed all over the model. The sequential stratigraphic method was applied throughout the modelling work flow, as stated in Chapter IV of the methodology during modelling process, hence lithology model was developed first, and its 3D Model results.

5.3.1 Facies model

a) Facies Model Results

Three different lithologies were defined and identified from SP and GR logs using an alpha mapping method presented on Table 5 .2 and Figure 2.1.

Table 5. 2: Statistics for Lithology Distribution in the model.

Code	Name	Percentage (%)
0	Sand and conglomerate	12.8
1	Fine sand	34.1
2	Shale	53.1
	Cells (nI x nJ x nK) 122 x 198 x 14	

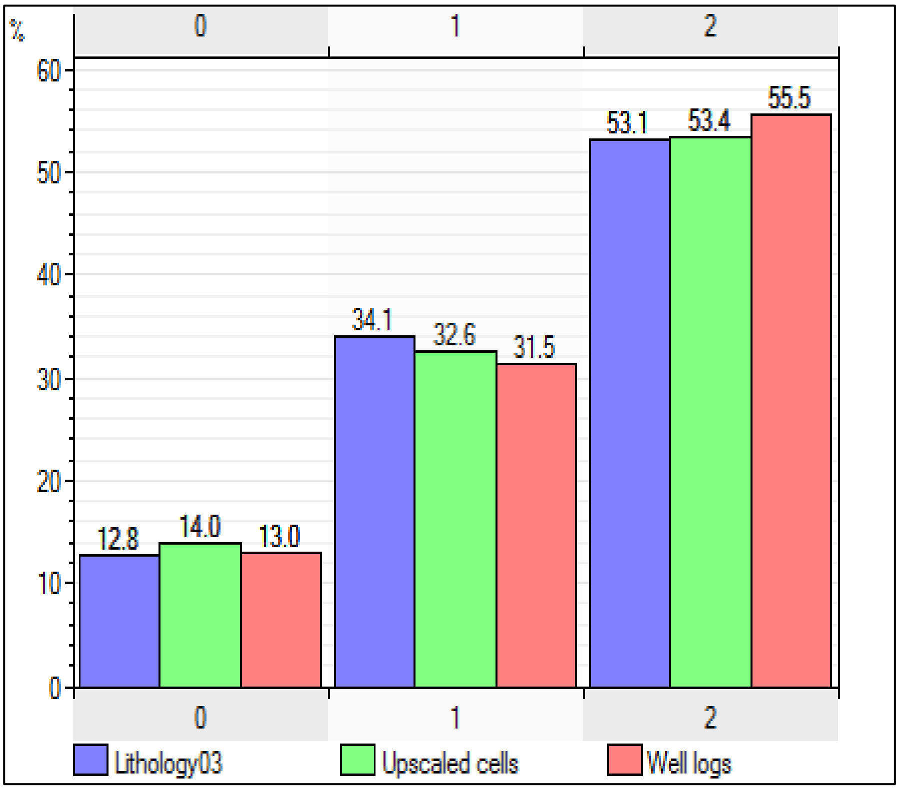


Figure 5. 1: Property, up scaled logs and original well logs.

a) Lithology/Facies model

The flow of Sand and conglomerate together with fine sand flow from North to South, this relates to the conception model generated by geologists from the field, so from the resulted model it's reasonable and valid to be carried forward for further development plans.

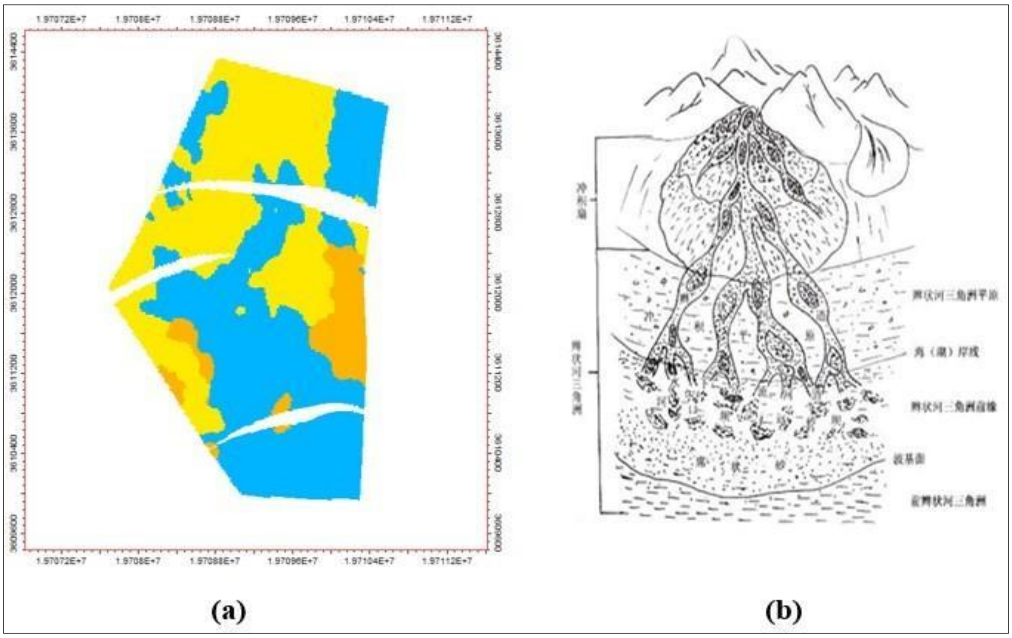


Figure 5. 2: (a) Shows the flow of Sand and conglomerate together with fine sand from North to South direction within a 3D Model. (b) A depositional model which shows an Alluvial fan-Delta sedimentary system in Xiaermen oilfield which trend from north to south direction, hence from the Alluvial fan-Delta sedimentary system map.

Using surfaces to control facies and property modelling is a powerful way to control your modelling and ensure that the property distribution agrees with the geological model Figure 5. 3.

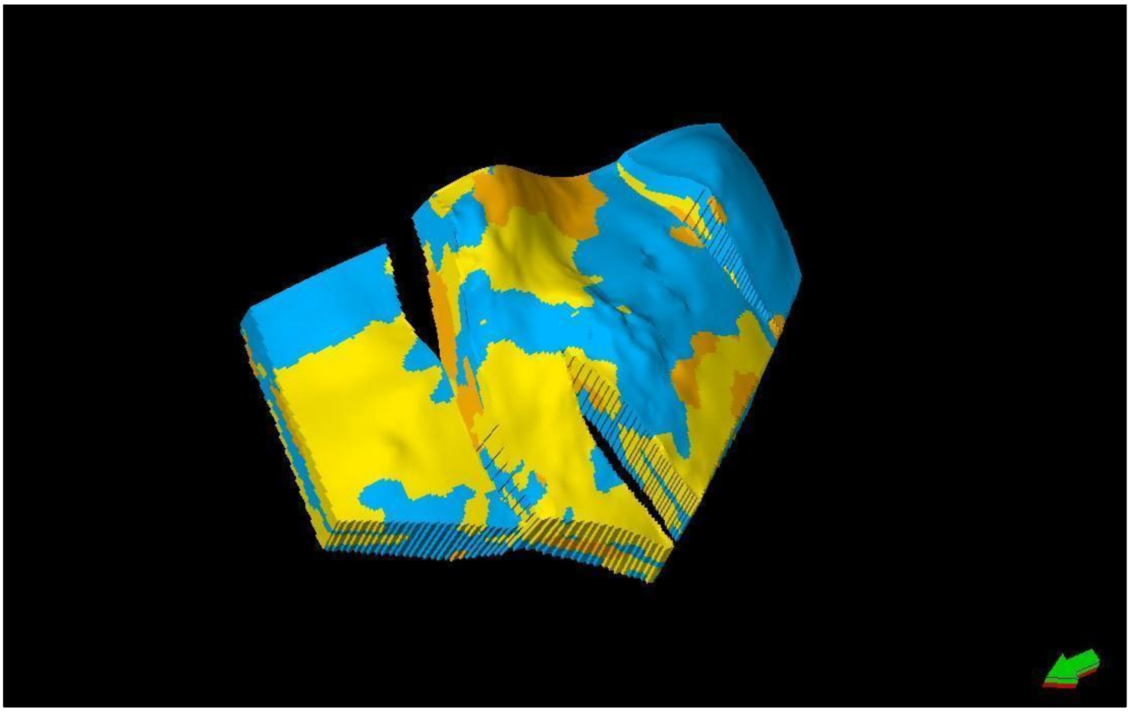


Figure 5. 3: 3D lithology model of H2V formation.

5.4 Petrophysical Properties

Petrophysical properties represent the crucial aspects of oil and gas exploration and production, helps in evaluating the potential of subsurface reservoirs to hold hydrocarbons and in optimizing the extraction process, to assess the quality and quantity of hydrocarbons present in a reservoir. This information guides decisions regarding well placement, drilling techniques, and production strategies, ultimately maximizing the recovery of oil and gas resources. A petrophysical evaluation emphasizes those properties relating to the pore system and its fluid distribution and flow characteristics, involving analyzing various rock and fluid properties within a reservoir to assess its potential for oil and gas production. This evaluation includes measuring parameters such as porosity, permeability, resistivity, and fluid saturation to understand the characteristics of the subsurface formations.

Table 5. 3: Petrophysical Properties of Xiaermen oilfield.

Fluid Properties	H2V Parameters
Crude oil density (g / cm^3)	0.8725
Volume factor Bo	1.091
Underground viscosity (mPa.s)	7.3
Ground viscosity (mPa.s)	10.25
Gas to oil ratio (m^3 / t)	22.4
Formation water viscosity	0.6 mPa.s
Surface water density	1.013 g/cm^3

5.4.1 Porosity model

Porosity is the fraction of void space in the rock that may contain fluid, in modelling results effective porosity is more needed than total porosity as its contribution to fluid flow is very essential during modelling to see how porosity has been distributed as well as total volume of hydrocarbon in place. From the model constructed, a resulting 3D porosity model was constructed using 16 porosities well logs out of 28 well logs. A Sequential Gaussian Simulation (SGS) method was used to simulate the distribution of porosity properties all over the geological model

Table 5. 4: Porosity model results.

Data:	Continuous (Porosity)
Min:	1.9
Max:	32.0
Mean:	17.3
Std. dev.	6.7

The resulting porosity model shows distribution of porosity over the whole model, with an average mean value of porosity of 17.3%. In H2V formation reservoir, its porosity value varies into different range. With very high porosity in some area and very low porosity value in some areas, this makes a reservoir to be heterogeneous. According to Levorsen (1967) this porosity reservoir, according to Table 5 .4, which represent a quality porosity evaluation. Porosity**,** according to (Webber, 1990) means a capacity of reservoir rocks to accommodate fluids. High porosity values indicate high capacities of the reservoir rocks to contain these fluids, while low porosity values indicate the opposite. Consequently, porosity data are routinely used qualitatively and quantitatively to assess and estimate the potential volume of hydrocarbons contained in a reservoir (Figure 5 .4).

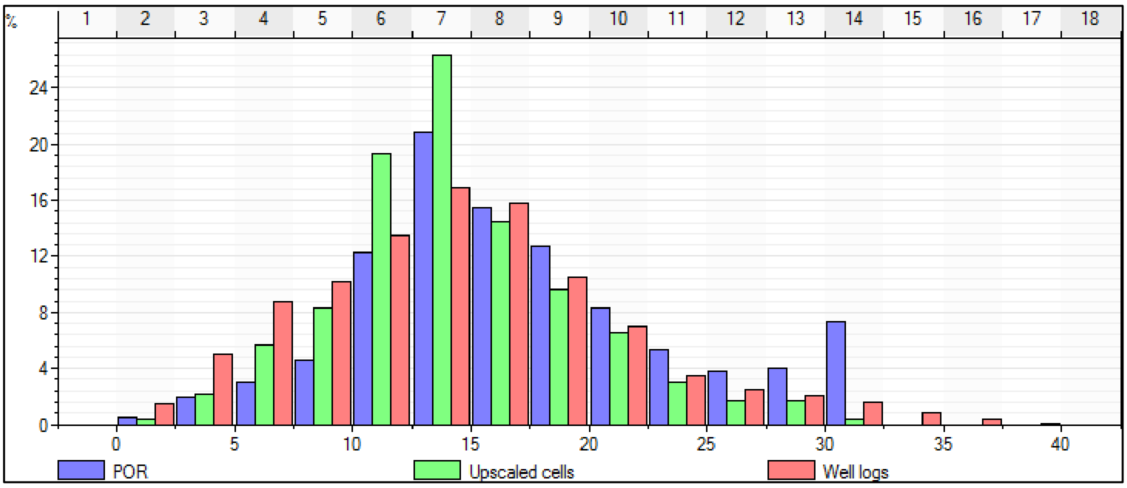


Figure 5. 4: Porosity distribution histogram.

He porosity model on its map view shows high porosity value from north to south, the trend follows the facies model distribution. Areas where there is sand and conglomerate together with fine sand from facies model. This implies the possibility for the reservoir to encounter high porosity distribution in some areas.

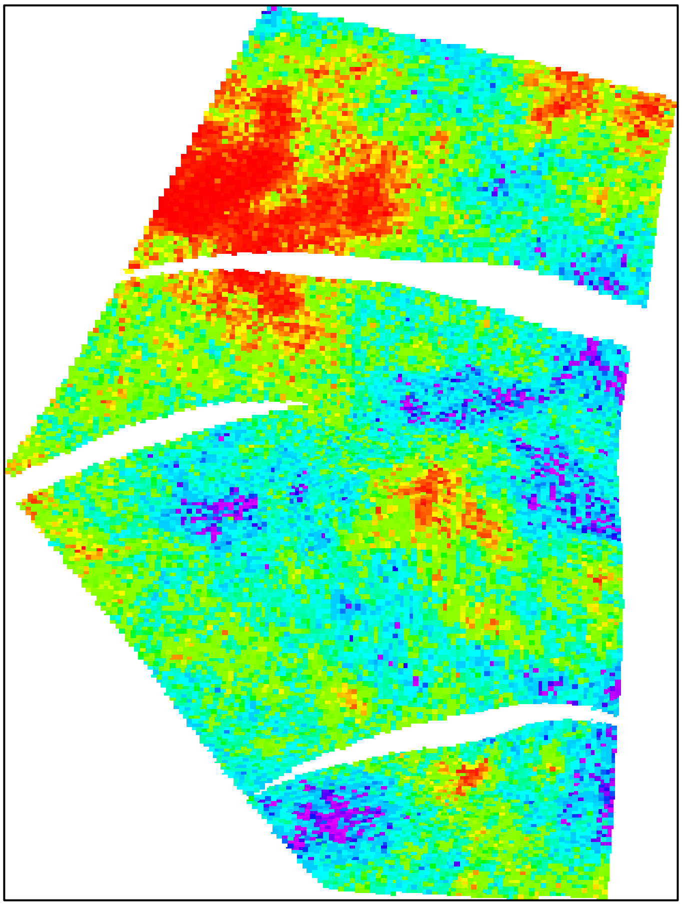


Figure 5. 5: 2D Porosity modelled, to Levorsen classification.

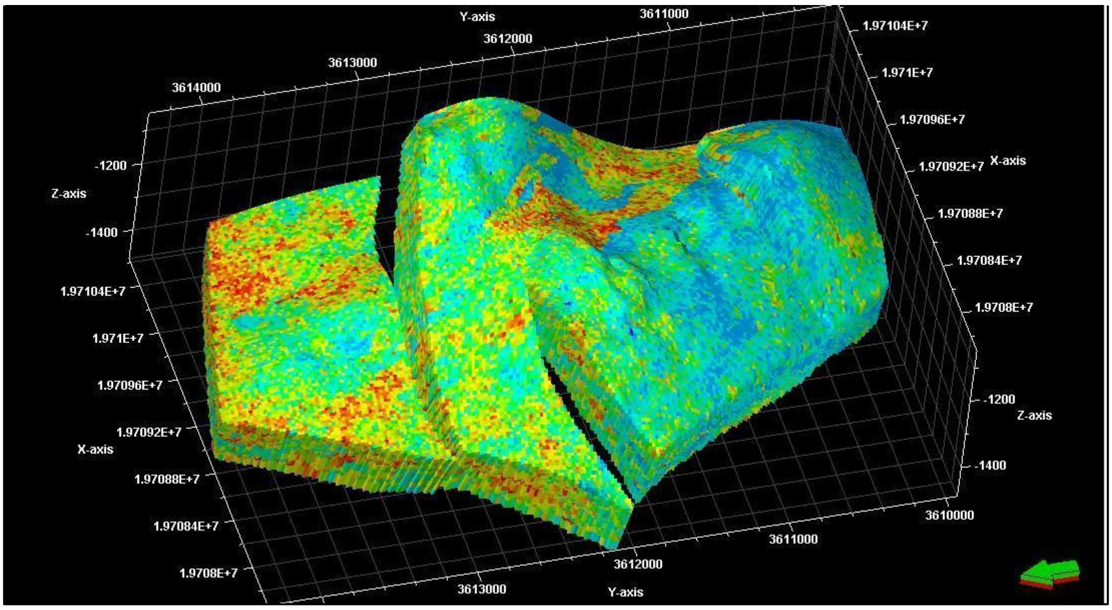


Figure 5. 6: 3D porosity geological model.

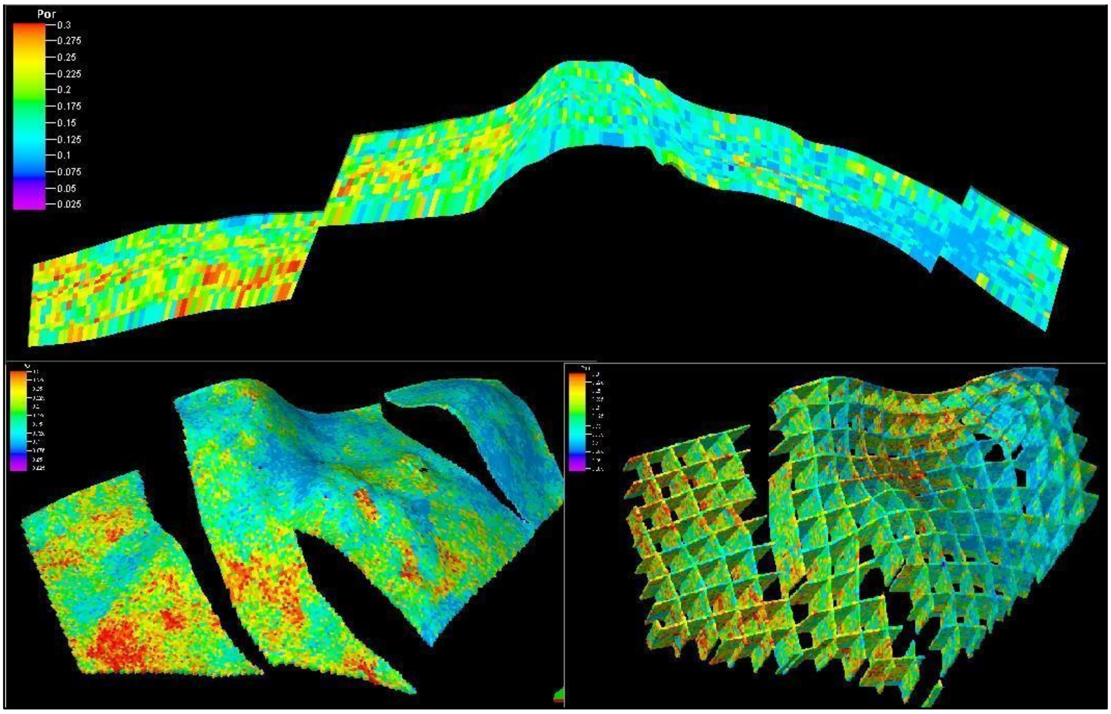


Figure 5. 7: Slice structure of porosity model.

5.4.2 Permeability model

Permeability measures the ability of reservoir rock to facilitate the flow of fluids within it. In this context, a Sequential Gaussian Simulation (SGS) method has been employed to simulate the distribution of permeability properties throughout the geological model. The sequentially simulation of permeability values at different locations within the geological model, employing Gaussian processes to capture the spatial correlation of these properties. The resulting simulated permeability distribution provides insights into the heterogeneity of the reservoir rock, aiding in the characterization and understanding of fluid flow dynamics within the subsurface formations.

Table 5. 5: Permeability model results.

Type of data:	Continuous (Permeability)
Min	1
Max	681
Mean	160

The distribution of permeability results refers to the pattern or arrangement of permeability values across a given geological or reservoir model. It provides insights into how permeability varies spatially within the subsurface formations. The results of permeability distribution are crucial for understanding the heterogeneity of the reservoir rock and its impact on fluid flow characteristics. Permeability distribution is often visualized through maps, graphs, or other representations that illustrate the range and variation of permeability values across the studied area. This information is essential for reservoir engineers, geologists, and other professionals involved in the oil and gas industry to make informed decisions regarding reservoir management, production strategies, and resource estimation.

The classification into these permeability categories assists in evaluating the reservoir's characteristics and plays a role in reservoir management, production planning, and overall understanding of subsurface fluid dynamics.

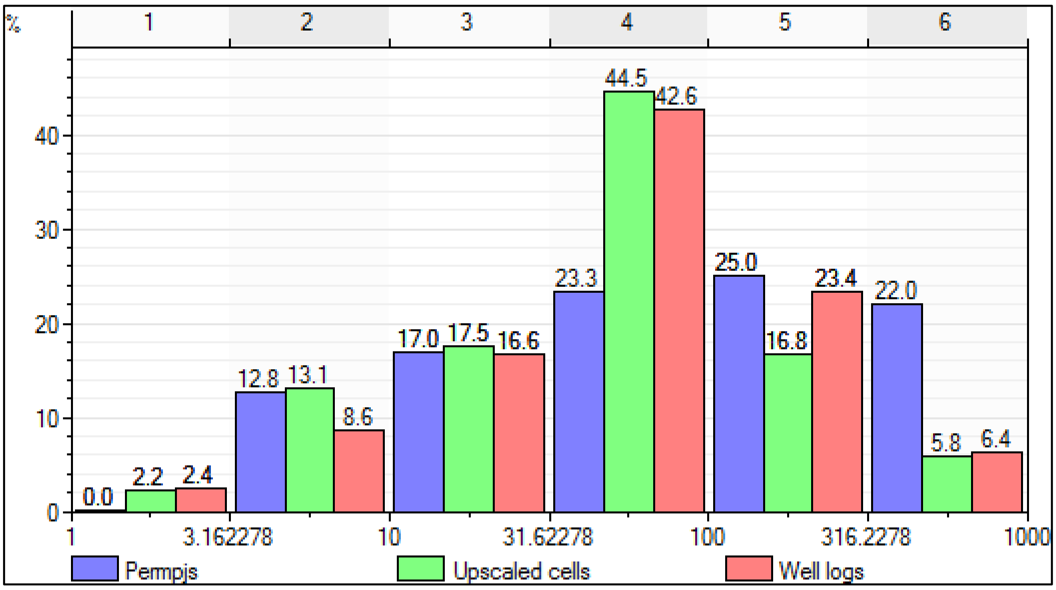


Figure 5. 8: Permeability results distribution.

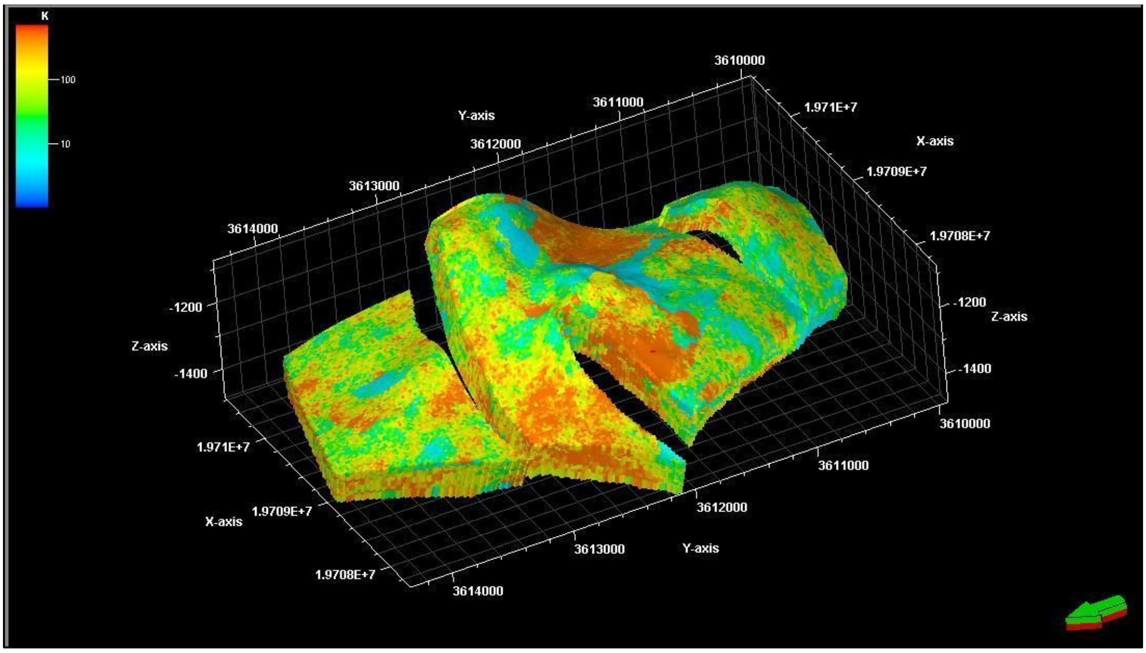


Figure 5. 9: 3D Perspective view of the permeability model. Permeability concentration vary from North to south as it is the same way as in a lithology model flow, where the area with high permeability is the same with where there is Sand and conglomerate together with fine sand facies rock type, the permeability model reflects to have a very good extent of reservoir rock that allow the flow of fluids.

5.4.3 Relationship between porosity, permeability and lithology

A plot of permeability, porosity and lithology (on logarithmic scale) it shows a trend and clear relationship between the three properties (Figure 5. 10). The PoroPerm cross-plot represent it's clearly shown how permeability of Sand and conglomerate with fine sand are particularly controlled by the porosity value (Figure 5. 11).

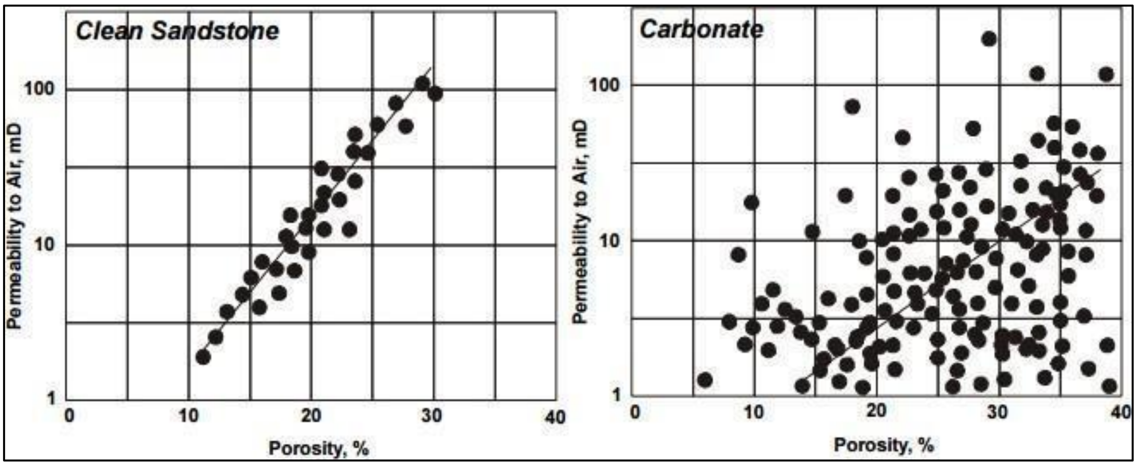


Figure 5. 10: Porosity and permeability relate in sandstone and carbonate reservoir. Porosity and permeability relate in sandstone and carbonate reservoir. This represents how porosity and permeability relate in sandstone and carbonate reservoir, as presented by (Glover, 2009). Where the large value of porosities implies there is more fluid flow pathway.

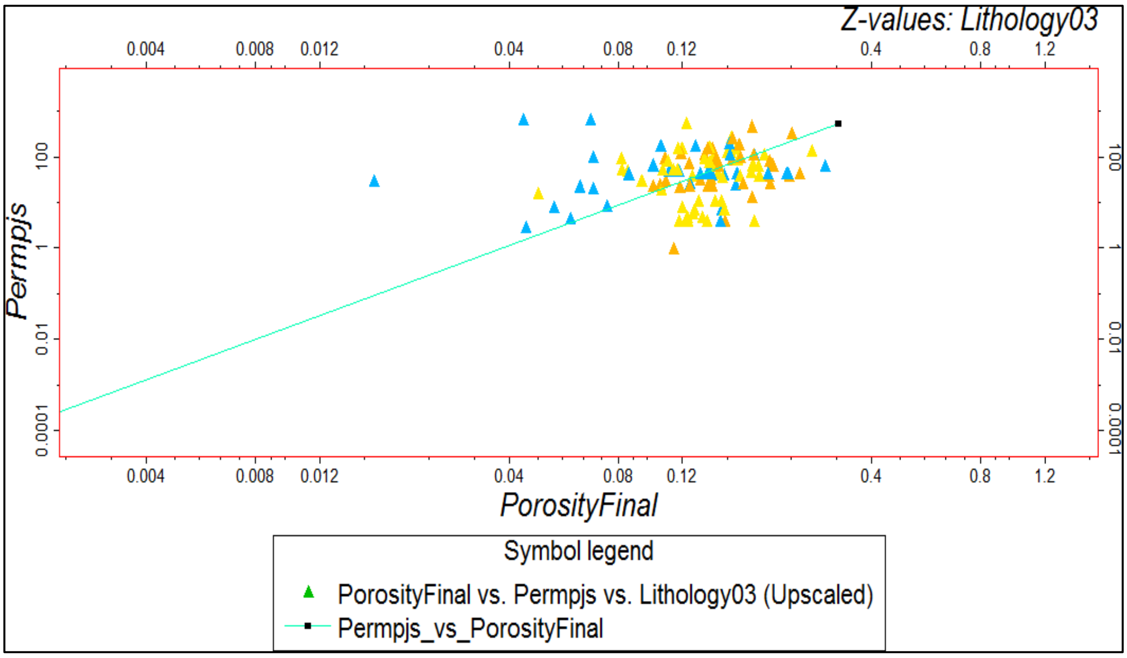


Figure 5. 11: Relationship between porosity, permeability and lithology. In areas where there was the highest permeability, porosity is also high. While lithology, rock contains Sand and conglomerate with fine sand are also dominated the area where there is high permeability and high porosity. While shale (blue) diverted from the line. Hence, permeability, porosity and lithology model show that the areas where these properties have high concentration have reflected the actual behavior of a good reservoir.

5.5 Net to Gross (NtG) model

The primary objective of the net-pay model was to quantify the volume of reservoir rock or productive rock while excluding non-productive or non-reservoir rock. This resulted in the creation of a 3D Net-to-Gross (NTG) model specifically for the H2V reservoir. The NTG model offers valuable insights into the distribution of productive rock within the reservoir. The Figure 5. 12 and Figure 5. 13, illustrate the outcomes of the net-pay model, providing crucial information regarding the quantity of hydrocarbons in place. These figures likely showcase the spatial distribution of net pay, indicating areas with a higher concentration of productive rock that contributes to hydrocarbon reservoirs.

The NTG model is instrumental in reservoir characterization, helping in the assessment of hydrocarbon reserves, planning for efficient extraction strategies, and overall reservoir management. It plays a key role in understanding the volumetric of the reservoir and aids in making informed decisions related to oil and gas exploration and production.

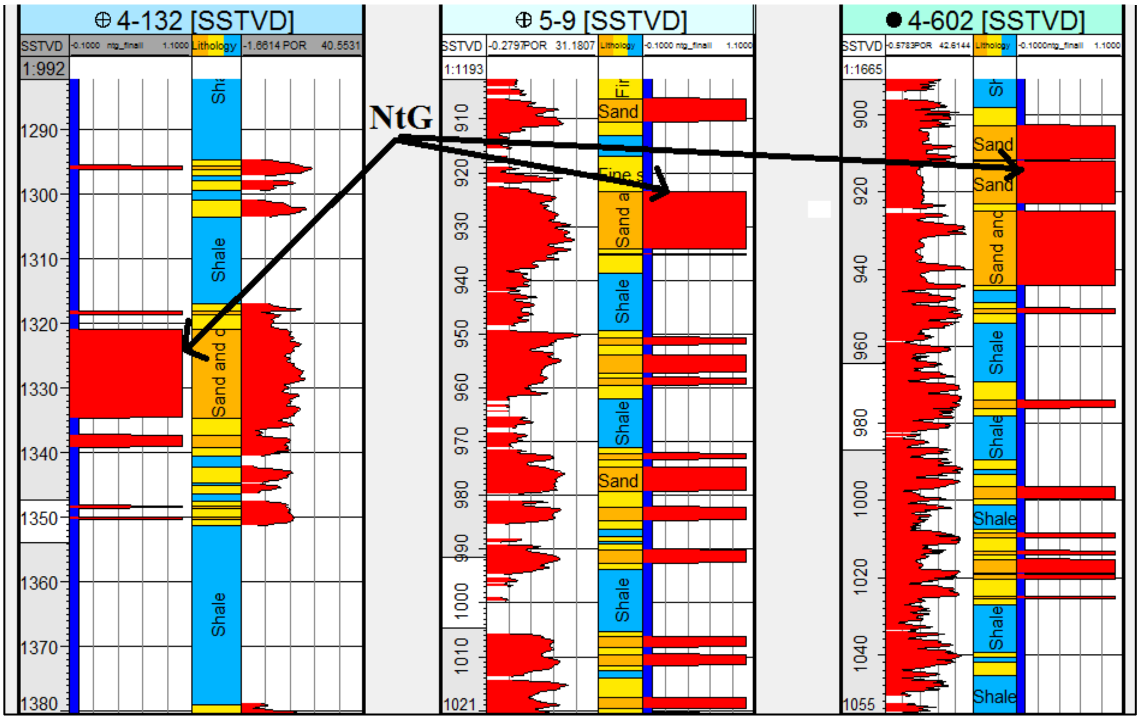


Figure 5. 12: NtG well correlation.

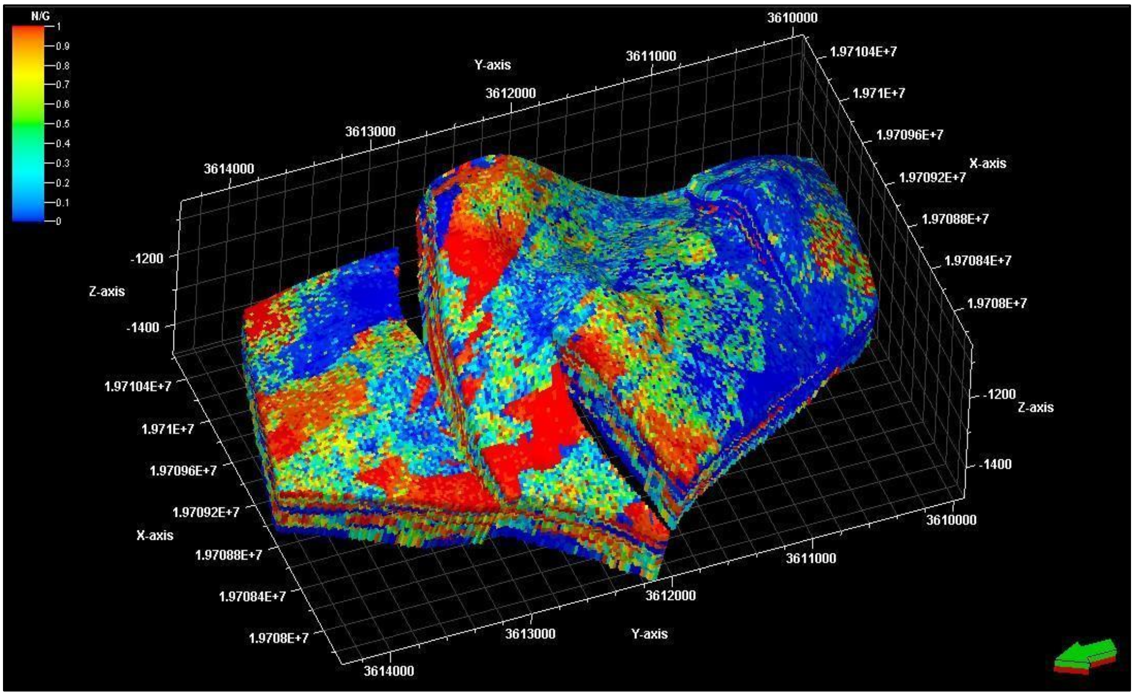


Figure 5. 13: 3D NTG model of a H2V reservoir, this model shows the most paying zone which has great probability of accommodating hydrocarbons in a reservoir.

5.6 Water Saturation model

The resulting constructed 3D model of water saturation in the H2V formation of Xiaermen oilfield exhibits an average value of 0.5. This model was developed using data from 16 well logs as secondary interpretation data. It is essential to note that areas with high water saturation are likely to have a lower content of oil, and conversely, regions with low water saturation may indicate a higher concentration of oil. By extracting oil saturation data from the water saturation model, it was observed that the flow direction was predominant from the north to the south of the model. Specifically, the middle and initial sections from the north demonstrated a higher concentration of oil. Figure 5. 14 and Figure 5. 15 visually represent the spatial distribution of water saturation and the derived oil saturation model. These figures provide a comprehensive view of the reservoir characteristics, highlighting areas where oil content is more pronounced based on the observed water saturation patterns. This information is crucial for reservoir engineers and geologists in making informed decisions about reservoir management, optimizing production strategies, and estimating the distribution of hydrocarbons within the subsurface formations.

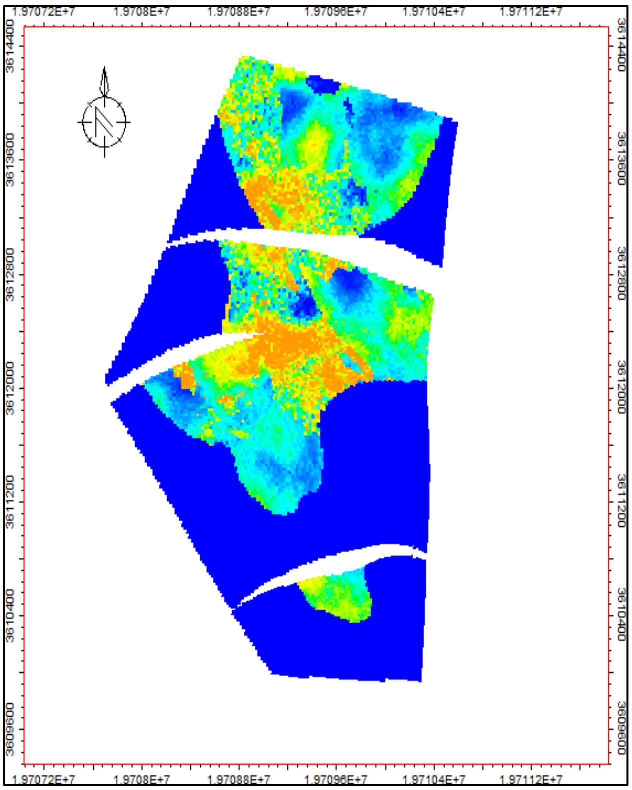


Figure 5. 14: 2D Water saturation distribution.

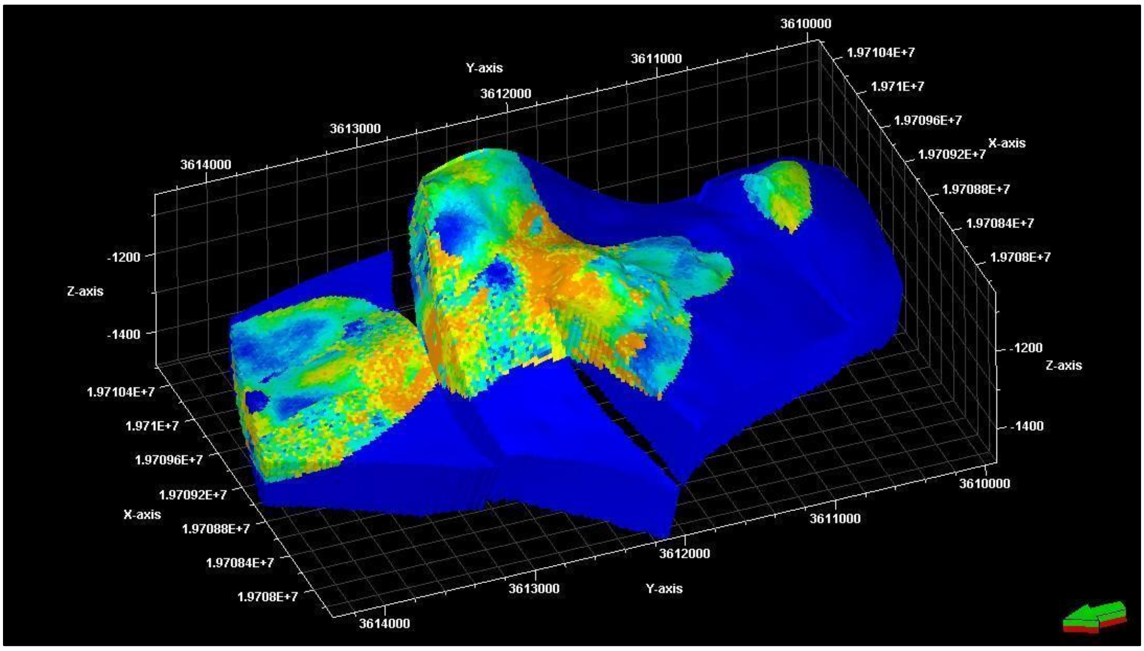


Figure 5. 15: 3D water saturation model.

5.7 Reservoir volumetric Results

5.7.1 Reserve estimation of H2V formation in Xiaermen oilfield

After a 3D reservoir, geological model was created based on well data of H2V formation in Xiaermen oilfield. In the table 11 are shown the total bulk volume of reservoir (901×10^6 m^3) in a model and the STOOIP for all 14 zones (229.3×10^4 t).

Table 5. 6: Total reserve in H2V formation.

	Bulk volume [*10^6 m^3]	Net volume [*10^6 m^3]	STOOIP [*10^6 sm^3]	STOOIP [*10^4 tons]	PRIMARY STOOIP [*10^4t]
Total	901	180	2.6291	229.3	218

The reserves within the H2V formation are economically viable. As the model reserve results align with the primary/original geological reserve (218x104t), this evidences that the calculated hydrocarbon content holds commercial value. Therefore, the reservoir model is well-suited for advancing production planning. It stands ready to serve as input for simulation and optimization studies of the reservoir, addressing various production challenges encountered in the field.

Table 5. 7: Input data for volume calculation.

Petrel 2013	**Schlumberger**
Date	**2023.01-2023.05**
Project	VOLUME CALCULATION
Model	**H2V Xiaermen model**
Grid	3D grid
General properties	
Porosity:	Porosity = 17.3%
Net gross:	0.2
Properties in oil interval:	
Sat. Water:	Sw
Sat. Oil:	1-Sw-Sg
Bo (formation vol. factor):	1.091
Rs (solution gas/oil ratio):	22.4
Facies used	
Sand and conglomerate	
Fine sand	
Shale	

This underscores the practical utility of the reservoir model in guiding decision-making processes and optimizing the overall production strategy for the reservoir. From the - Table 5. 8 and Figure 5. 16, displays the calculated STOOIP (Stock Tank Oil Originally in Place) alongside diagrams illustrating the statistical distribution of various resource estimates. It is evident from the table that there are significant uncertainties associated with the resulting resource potential estimates. These uncertainties arise due to sparse data coverage, discrepancies in thermal maturity data, and a lack of information regarding reservoir fluid properties and subsurface pressure-volume-temperature conditions. The limited data coverage and variations in available data contribute to substantial uncertainties in estimating hydrocarbon volumes and predicting their types.

Table 5. 8: Calculated STOOIP.

	BULK VOLUME [*10^6 m^3]	**NET VOLUME [*10^6 m^3]**	**STOOIP [*10^6 sm^3]**	**STOOIP [*10^4 tons]**	**PRIMARY STOOIP [*10^4t]**
Zone	88	18	0.3918	34.1	---------
Zone	88	18	0.3443	30	2.58
Zone	40	8	0.1758	15.3	21.5
Zone	34	7	0.1542	13.4	15.67
Zone	95	19	0.3136	27.3	7.22
Zone	34	7	0.115	10	14.13
Zone	47	9	0.1259	10.9	27.48
Zone	38	8	0.1148	10	17.77
Zone	38	8	0.1609	14	6.25
Zone	84	17	0.2523	22	6.47
Zone	77	15	0.2276	19.8	43.78
Zone	45	9	0.0945	8.2	29.74
Zone	43	9	0.0689	6	3.65
Zone	150	30	0.0896	7.8	21.65
Total	**901**	**180**	**2.6291**	**229.3**	**218**

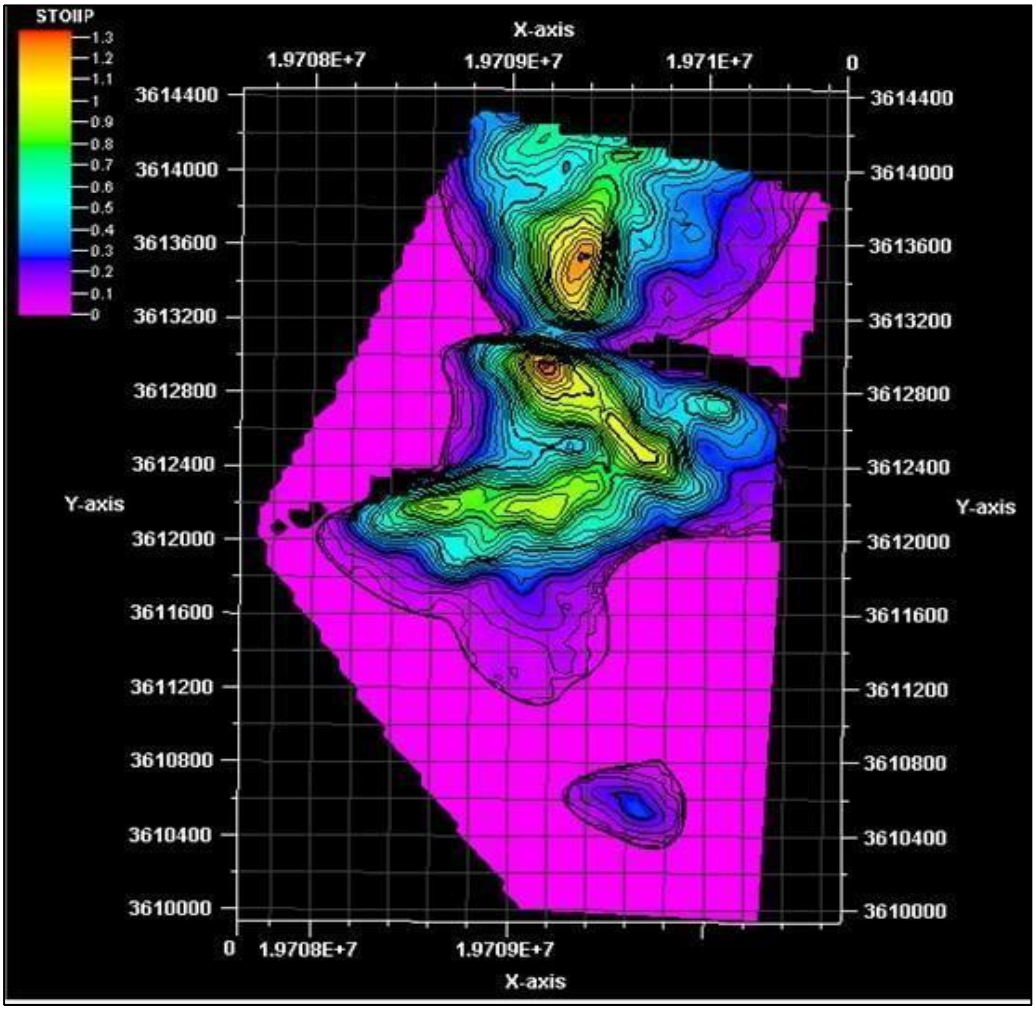


Figure 5. 16: Oil resource (in-place) density map showing the spatial distribution of the predicted oil resource in the H2V Formation.il distribution map.

Chapter VI - CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

In conclusion, the investigation into well data-driven 3D reservoir modelling of the Xiaermen oilfield has yielded significant insights into the reservoir's characterization and behavior. The 3D reservoir model has proven valuable for reserve estimation, identifying potential targets, locating sweet spots, and areas with the potential for hydrocarbon production.

The model demonstrates its potential through the calculated and trended properties at defined depths. The constructed 3D geological model of the H2V formation in the Xiaermen oilfield reservoir is promising due to its favorable porosity and permeability values. The average porosity in the model stands at 17.3%, while the permeability model shows an average value of 160mD. According to Levorsen, the reservoir exhibits a well-distributed porosity and permeability, indicating an extensive reservoir rock with favorable fluid flow characteristics. Furthermore, the reservoir facies model illustrates a clear trend in property distribution from the northern to the southern part, resembling a proposed depositional model. The distribution includes 13.99% of sand and conglomerate, 32.57% of fine sand, and 53.44% of shales.

Finally, by comparing the calculated volumetric parameter (STOOIP) of the reservoir fluid content in the H2V formation of the Xiaermen oilfield with the primary geological reserves, the study reveals that the original geological reserve was 218x104t, while the calculated geological reserve from the created model was 229x104t. The close correlation between reserve fitting and the original reserves indicates the good accuracy of the 3D geological model, recommending its use for further field development plans.

6.2 Recommendations

Well data driven for 3D reservoir modelling of a reservoir and main key point of this process consist on data collection and control as well as the integration of the collected data to be accounted on reservoir characterization, the constructed 3D Geological model of H2V formation of Xiaermen oilfield has provided a better understanding of the spatial distribution of the discrete and continuous properties in the field, it's recommended to:

1. Develop a geological model to be updated as new data are acquired for field development and for dynamic reservoir numerical simulation, the generated model is static.
2. Establish a framework for continuous model updating by using production data and surveillance data to incorporate real-time reservoir performance.
3. Integrate production and pressure data to ensure it accurately reproduces historical reservoir behavior.

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