AN APPROACH TOWELL PLACEMENT AND PRODUCTIONIN A GREEN FIELD – A CASE STUDY

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By

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ABSTRACT

Reservoir development planning and well placement significantly affect hydrocarbon recovery. Therefore, strategic well placement and development techniques are essential to minimize the risk of unproductive drilling and also to maximize production within the reservoir.

This study presents an approach to well placement and production in a green field. A 3D static model of the green field was built using geostatistical techniques to distribute the various model petrophysical properties such as porosity, thickness, and permeability in order to provide reliable reservoir description for dynamic modeling. A dynamic model was constructed to evaluate various reservoir development problems, including well placement, number and types of wells to be drilled in the green field. The drilling of both vertical and horizontal wells was considered in the analysis. Finding the optimal length of the horizontal well to be drilled in order to maximize oil recovery and to properly develop the reservoir was considered a significant problem to address. A sensitivity analysis was carried out to evaluate the impact of horizontal well length on oil recovery. The vertical to horizontal permeability anisotropy (kvkh) was also studied in this work.

The results of the analysis indicate that horizontal well length influences cumulative oil production. Drilling a 3000ft. long horizontal well was found to produce a higher cumulative volume of oil than the oil recovery obtained from similarly placed horizontal wells but with shorter lengths of 2000 ft. and 1500 ft.

It is concluded that the methodology proposed in this study will find application in the development of a green field.

Keywords: Reservoir development, well placement, simulation, petrophysical property distribution, geostatistics, permeability, porosity, thickness

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My utmost appreciation goes to our Heavenly Father for His guidance, care, protection, love, wisdom and strength throughout my stay in this University.

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Furthermore, I would like to express my sincere gratitude to Dr. Akeem Olatunde Arinkoola and all my loved ones who have contributed in diverse ways to the success of this work.

God richly bless you all.

DEDICATION

To my wife

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CHAPTER 1

INTRODUCTION

1.1 Statement of Problem

Reservoir development and well placement have been one of the existing challenges in the petroleum industry over the years. This is because different engineering, geological and economic variables affecting reservoir performance are practically involved.

More importantly, the decision on how to increase oil recovery and maximize the economic profitability of field development projects is the pivot point. Therefore, an extensive evaluation of certain decision variables such as reservoir properties, production scheduling parameters, type of well, location to drill new wells and an effective technique to obtain the best economic strategies are required. Also, consideration should be given to the spatial distribution of geological and rock properties such as porosity and permeability in order to locate potential hydrocarbon zones for drilling activities. This involves critical evaluation of development strategies to produce the greatest amount of hydrocarbons within the physical and expected economic limits.

Several techniques have been adopted to achieve efficient reservoir development process which significantly affects the productivity and economic benefits of an oil reservoir. However, the aim of this work is to evaluate the impact of well placement on cumulative oil recovery during the development of a green field.

In this study, reservoir simulation and spatial based modeling approaches will be used as key evaluating elements for the development of the greenfield oil reservoir to improve its productivity.

1.2 Objectives

The objectives of this study are to:

- Use geostatistical methods to distribute the petrophysical properties in building a 3D static model of the reservoir;
- Find the optimum number, type, and placement of wells required to develop the greenfield.

1.3 Methodology

The methods to be used include;

- Build a 3D static model of the green field by
  - Digitization of structural and isopach maps of the A-1 reservoir
  - Estimation and distribution of Porosity, Permeability, and Thickness at all locations in the reservoir
  - Estimation of Original Oil in Place (STOOIP)
- Construction of a 3D dynamic reservoir model
- Use of the 3D dynamic model to find the optimum number, type, and placement of wells to develop the reservoir.

1.4 Facilities and Resources

The facilities and resources used for this project include;

- AUST library and internet facilities
- Technical and academic expertise of supervisor
- Structure and Isopach maps of A-1 reservoir
- Isopermeability map of A-1 reservoir
- Isoporosity map of A-1 reservoir
- Computer software programs such as: GIS, SGeMS, Sensor Simulator

1.5 Organization of Report

This report is organized into five chapters. Chapter one is the introductory chapter giving general information about the entire project. Chapter two gives in-depth information of the study area and reviews relevant literature related to this work. Chapter three places emphasis on data processing and analysis. Chapter four covers the results and discussion. The last chapter which is chapter five concludes the project and provides the necessary recommendations.

CHAPTER 2

LITERATURE REVIEW

2.1 Geological Background of the Field

2.1.1 Reservoir Description

A-1 reservoir has a geometry comparable to channel sand with a gently west dipping slope. The structure has a maximum elevation difference of approximately 60ft. with a thickness of approximately 40 to 50ft. The average net-pay thickness is 20ft. The compressibility of the formation is approximately 3.0 x 10^{-6} psi^{-1}. At 9290 reference depth, the initial saturation is estimated to be S_{oi} = 77%, and S_{wi}=23%. At the reference depth of 9290 ft., initial formation pressure is measured to be 4800 psia(Ertekin et al, 2001).

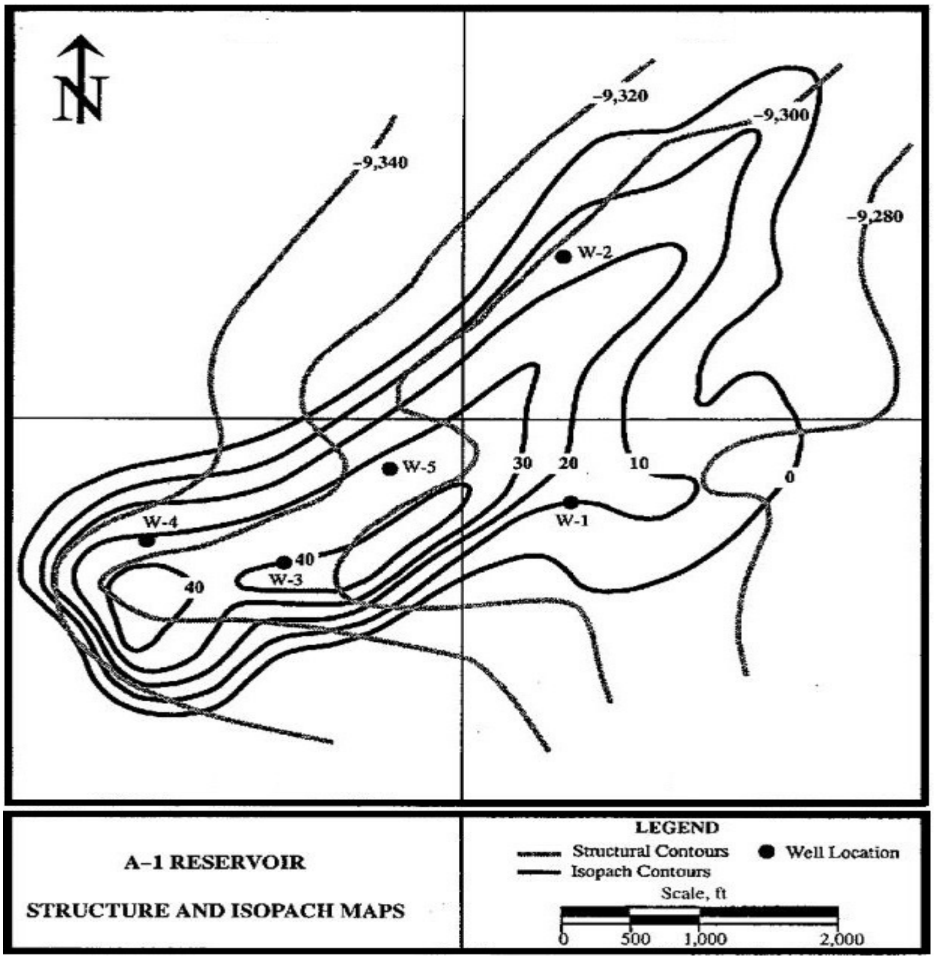

Figure 2.1 Structural and Isopach map of A-1 Reservoir (Source: Ertekin et al, 2001)

2.1.2 Porosity and Permeability

The A-1 formation consists of poorly-to-well-sorted Cretaceous Dakota J sands. The average effective porosity of the reservoir is 22%, with permeability ranging from 250 to 300 md. Figures 2.2 and 2.3 show the porosity and permeability distributions obtained from well-test data and core analysis. The permeability distribution in Figure 2.3 represents the permeability values along the longitudinal axis of the structure in the SW-NE direction. Permeability values along y-direction are reported to be approximately 80% of that along the x-direction. Hence, the flow directions are parallel to the SW-NE and SE-NW direction (Ertekin et al, 2001).

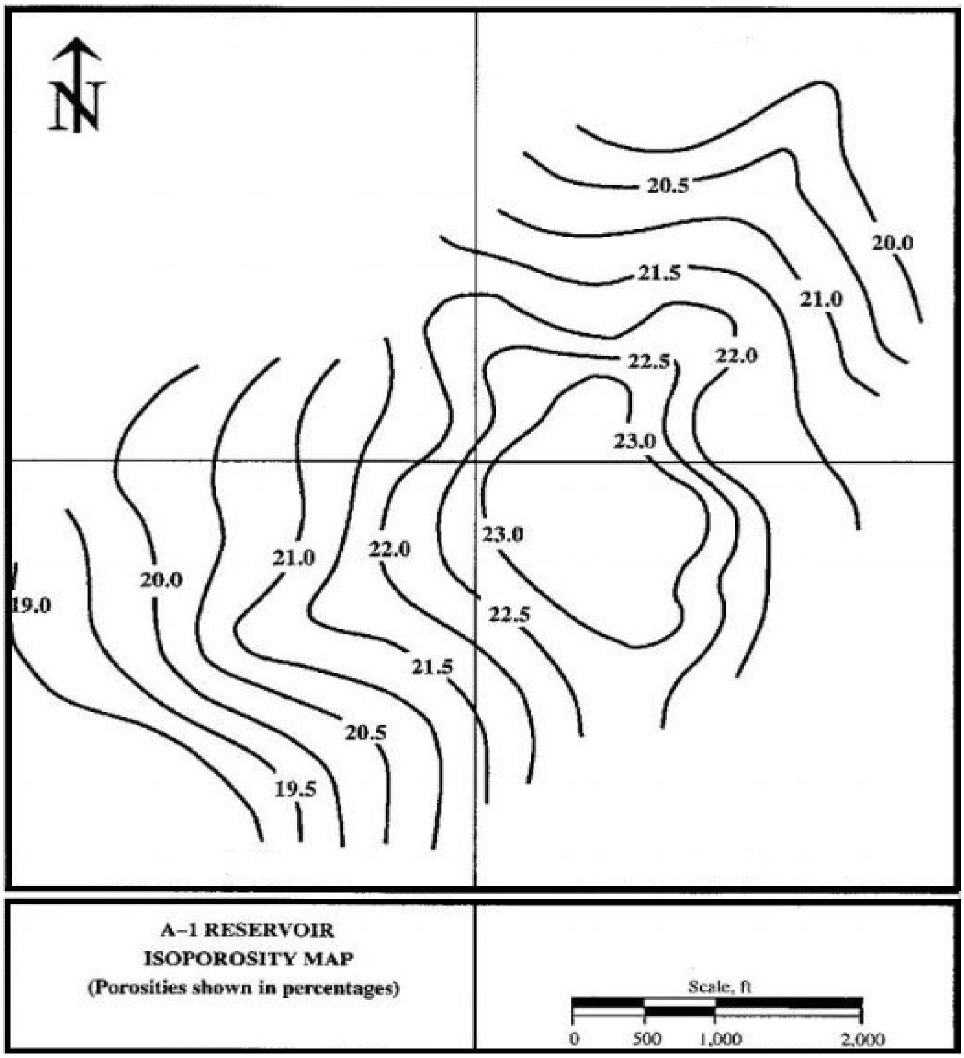

Figure 2.2 Porosity Distribution for A-1 Reservoir (Source: Ertekin et al, 2001)

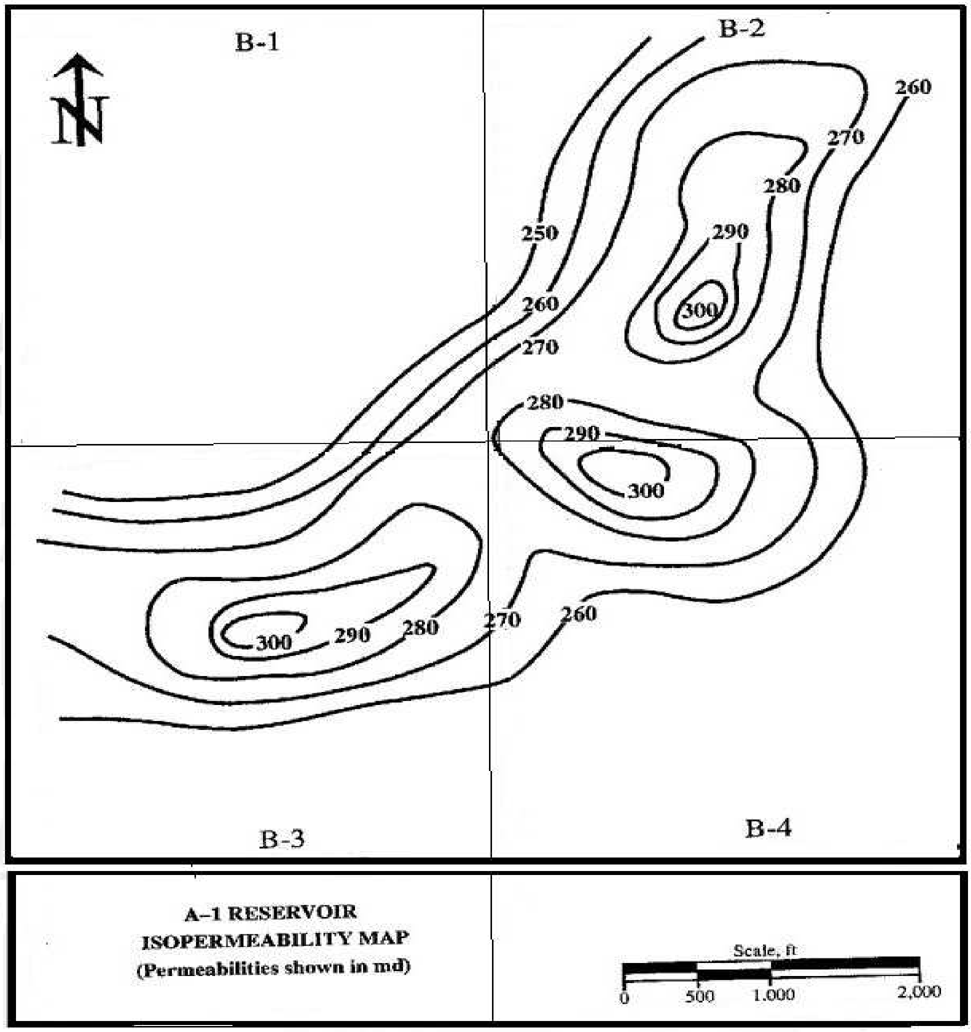

Figure 2.3 Permeability Distribution of A-1 Reservoir (Source: Ertekin et al, 2001)

2.2 Literature Review

2.2.1 Introduction

Reservoir development requires huge investments. The decision for making these investments is based on several factors including reservoir performance predictions and well placement.

To achieve sound reservoir performance predictions, a reliable geological model is needed. Geostatistics attempts to improve predictions by developing different types of geological models. It uses methods that do not average important reservoir properties to construct a more realistic model of reservoir heterogeneity. Like the traditional deterministic approach, it preserves indisputable “hard” data where they are known and interpretative “soft” data where they are informative (Wilson et al. 2011).

In addition, petrophysical properties distribution is essential in building static models of the reservoir. One of the new technologies often incorporated into the process is geostatistics (Cressie and Hawkins 1980; Bueno et al. 2011). For more than a decade, geostatistical techniques have been an acceptable technology used to characterize petroleum reservoirs (Qi et al., 2007; Abdideh and Bargahi 2012; Esmaeilzadeh et al. 2013; Fegh et al., 2013).

Lastly, strategic well placement techniques are needed to maximize production. Therefore, the determination of the optimum number, type, and location of wells is very important in field development. This problem has recently gained more attention as a result of the increase in the world's energy demand and increasing pressure to maximize recovery with minimum investments in oil fields. With easy onshore fields becoming rare and many of the world's major fields reaching maturity, new expensive offshore developments are becoming more attractive. Hence the need for optimized reservoir performance is becoming more important every day(Nasrabadi et al.,2011).

2.2.2 Geostatistical Modeling of Property Distributions

The main aim of using geostatistics is to provide a fair assessment of geological uncertainty and a realistic model of variability. Geostatistics is used to generate many realizations of a 2D variable that represents the reservoir quality over the stratigraphic interval.

- Variogram

Variogram is the most commonly used geostatistical technique for describing a spatial relationship. For reservoir modeling we need to express spatial variation of parameters, and the central concept controlling this is the variogram. The variogram captures the relationship between the difference in value between pairs of data points, and the distance separating those two points.

Numerically, this is expressed as the averaged squared differences between the pairs of data in the data set, given by the empirical variogram function, which is most simply expressed as:(Philip, 2012)

$$2\gamma = (1/N)\ \Sigma\ (z_i - z_j)^2 \qquad \text{Equation 2.1}$$

Wherezi and zj are pairs of points in the dataset. For convenience we generally use the semivariogram function:

$$\gamma = (1/2N)\ \Sigma\ (z_i - z_j)^2 \qquad \text{Equation 2.2}$$

The semivariogram function can be calculated for all pairs of points in a data set, whether or not they are regularly spaced, and can therefore be used to describe the relationship between data points from, for example, irregularly scattered wells. A more formal definition of semi-variance is given by:

$$\gamma(h) = ½ E\{Z(x+h) - Z(x)^2\} \qquad \text{Equation 2.3}$$

Where

E ¼ the expectation (or mean)

Z(x) ¼ the value at a point in space

Z(x + h) ¼ the value at a separation distance, h (the lag)

Generally, γ increases as a function of separation distance. Where there is some relationship between the values in a spatial dataset, γ shows smaller values for points which are closer together in space, and therefore more likely to have similar values (due to some underlying process such as the tendency for similar rock types to occur together). As the separation distance increases the difference between the paired samples tends to increase. Fitting a trend line through the points on a semivariogram plot yields a semivariogram model and it is this model which may be used as input to geostatistical packages during parameter modeling (Philip, 2012).

- Kriging

Kriging is a mapping method/estimation technique based on fundamental statistical properties of the data, the mean, and the variance. Kriging uses an interpolation function:

$$Z^* = \sum_{i=1}^{n} \omega i Z i \qquad \text{Equation 2.4}$$

Where ω_i are the weights, and employs an objective function for minimization of variance.

Thus, a set of weights is found to obtain a minimum expected variance in the presence of available known data points. The algorithm finds values for ω such that the objective function is honored. The correlation function provides gradual changes, and Kriging will tend to give a smooth function which is close to the local mean. Depending on the assumptions made, Kriging can be done in several ways. Simple Kriging is mathematically the simplest. It assumes that the mean of the distribution is known and that it is statistically stationary (i.e. a global mean). Ordinary Kriging is most commonly used. This is because it assumes slightly weaker constraints, the mean is unknown but constant (i.e. a local mean) and that the variogram function is known (Philip, 2012).

- Sequential Gaussian Simulation

Gaussian Simulation covers many related approaches for estimating reservoir properties away from known points. Sequential Gaussian Simulation, SGS is most commonly used for modeling continuous petrophysical properties. A good geostatistical model should depict petrophysical structure and variability and can be used for flow simulation and for studies to define drilling targets. However, a single realization is only one possible outcome, and several realizations need to be simulated to assess the probability of occurrence and variability. In practical terms, one realization may be used to define static heterogeneity for a flow simulation model, but one realization would be little value in planning a new well location. In terms of well planning or reserves estimation, an average expectation from the Kriging model, or many realizations, would give a more statistical stable estimate (Philip, 2012).

- Sequential Indicator Simulation

This is a simple modification of SGS where a particular threshold value of the simulated Gaussian random field is used to identify petrophysical property groups or rock elements, such as porosity > X but treats the probability function and the conditioning data as a discrete (binary) variable from the outset (Journal and Alabert, 1990). The indicator transform is defined by:

$$i(\dot{\upsilon}; z) = \begin{cases} 1, & if z(\dot{\upsilon}) \leq z \\ 0, & if not \end{cases} \qquad \text{Equation 2.5}$$

Where z is the cut-off value for a field of values ὺ. The field u could be derived from, for example, porosity data, the gamma-ray log or seismic impedance. The choice of the indicator value is an important decision. Both these methods are useful for modeling rock elements as well as for modeling property distributions within elements(Philip, 2012).

2.2.3 Well Placement

Well placement within a reservoir is one of the challenging steps in the reservoir development process. There are many things to consider in a well placement optimization. These include number, type, timing, and location of wells. These parameters are interdependent hence their selection is not always straightforward.

- Number of Wells

The decision on the number of wells is a balance between expected production and the cost associated with drilling, completing, and operating these wells. There is little uncertainty in estimating the cost of wells; however, the uncertainty in estimating production capacity of each well is large since the geology is inherently uncertain and there are many physical approximations implicit to flow simulation (Deutsch et al., 2001).

- Type of Wells

One important parameter that needs to be considered in well placement optimization is the type of wells. There are different types of wells that can be drilled. However, a particular well type may be most economical in the process of recovering hydrocarbon. Various drilling strategies can be used to place wells in specific patterns with the aim of maximizing production within the reservoir. For the past few years, horizontal and vertical wells have been used as the standard well type in oil field development projects. Recently, technological advancements have enhanced drilling of more sophisticated nonconventional well trajectories, which come in a variety of forms such as Maximum Reservoir Contact (MRC) wells and Multilateral Wells (MLWs). Several other studies have showed that the performance of nonconventional wells is superior in many areas as compared to conventional wells. These advantages include extending reservoir drainage area and contact length, reducing operational drawdown pressure, increasing net worth of the drilling investment, and reducing producing gas-oil ratio (Horn et. al., 1997; Taylor et. al., 1997).

- Timing of Wells

Determining the best timing of opening and closing injection and production wells relies on several reservoir related conditions such as the expected breakthrough time of water or gas, the presence of thief zone water/gas, and time-dependent pressure and geomechanical effects as well as economic conditions, for instance the cost of treating water and gas (Jonas et al., 1997).

- Location of Wells

One of the most important considerations for designing an optimal well plan is the location of wells. Many well plan optimization studies have focused on this aspect of the well plan alone. The most significant factor involved in this decision is the geology and its inherent uncertainty. The number of possible well locations is large considering the reservoir space available to accommodate these wells. Simulated annealing is often well suited to solve this type of optimization problem with a number of physical and economic constraints(Deutsch et al., 2001).

2.3 Literature Summary

Building a large number of reservoir static models to capture uncertainty is fundamental in reservoir development planning. It is necessary to use geostatistical methods to distribute the petrophysical properties in building those static models of the reservoir.

In addition, the determination of the optimum number, type, and location of wells is a challenging step in field development. However, a number of research works relating to well placement and reservoir development have been discussed in literature.

Nogueira and Schiozer (2009) proposed a methodology for optimizing well placement using two optimization stages. The procedure starts by creating reservoir sub-regions equal to the maximum number of wells. Then, a search for the optimum location of a single well is performed in each sector. The second stage aims to optimize well quantity through the sequential exclusion of wells obtained from the first stage. They optimized both vertical and horizontal wells in separate studies. They also concluded that the proposed modularization of the problem speeds up the optimization process for their problem of consideration.

Handels et al. (2007) and Wang et al. (2007) proposed different approaches for well placement by using gradient-based techniques for representing the objective function. They then calculated the gradient of this function and used the steepest ascent direction to guide the search. For the examples they considered, these methods seemed promising due to their efficiency in terms of the number of simulation runs. The techniques were only applied to vertical wells.

This thesis work attempts to use geostatistical methods to distribute the petrophysical properties in building a 3D static model of the reservoir and also find the optimum number, type, and placement of wells required to develop the field.

CHAPTER 3

METHODOLOGY

DATA PROCESSING AND ANALYSIS

3.1 Data Acquisition

The data used for this project include: an isoporosity map,an isopermeability map, structure and isopach maps of A-1reservoir downloaded via the American Association of Petroleum Geologists data page at http://archives.datapages.com/data/rmag/oilgasfields82/plumbush creek.htm. The maps were digitized to reproduce reservoir properties and the coordinates used for the analysis.

3.2 Outline of Methodology

The methods adopted for the analysis are as follows:

- Digitization of structural and Isopach maps of A-1 reservoir
- Estimation of Porosity, Permeability and Thickness at the unsampled locations
- Estimation of Original Oil in Place (OOIP)
- Reservoir dynamic modeling

3.2.1 Digitization of Structural and Isopach Maps of A-1 Reservoir

The structural and isopach maps were digitized and their corresponding coordinates were used to produce a digital terrain model (DTM) and contour map of reservoir A-1 as shown in Figure 3.1 and Figure3.2. The permeabilities and porosities and thickness values obtained from the isopermeability and isoporosity maps were used for the geostatistical modeling.

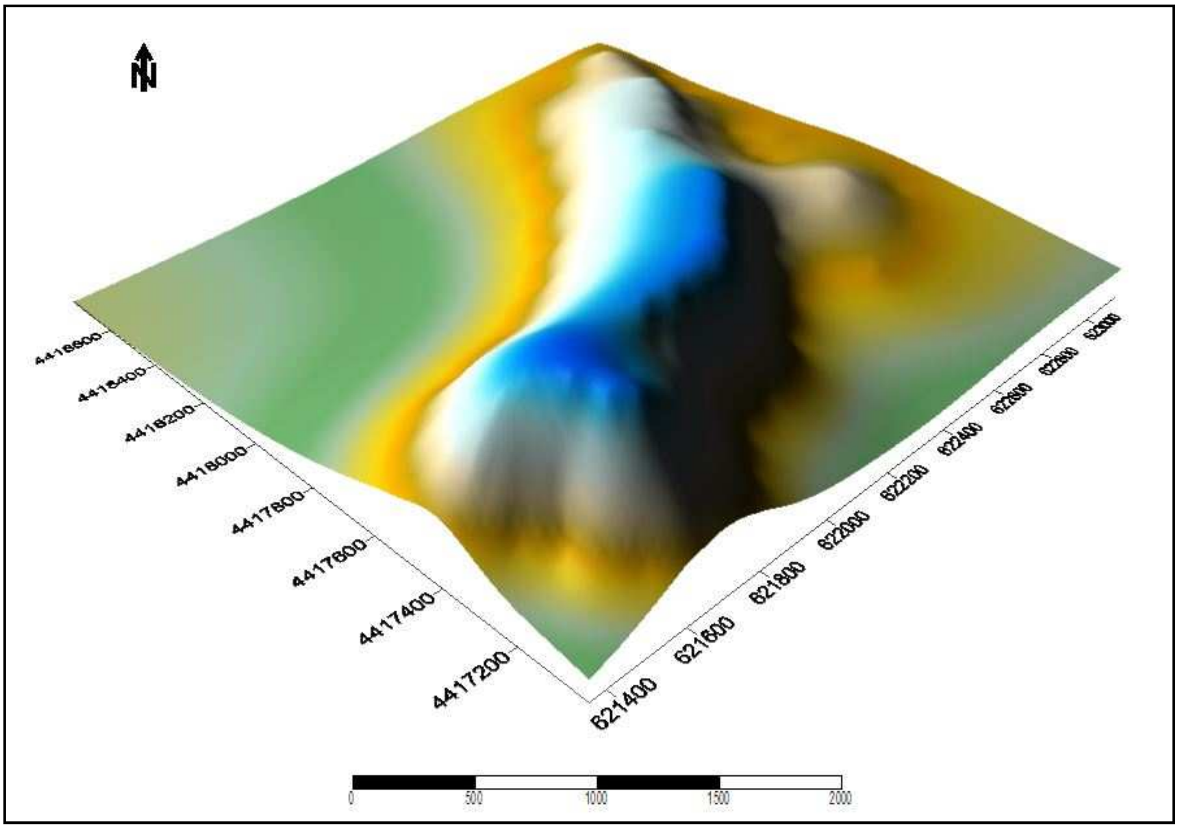

Figure 3.1: Digital Terrain Model of A-1 Reservoir

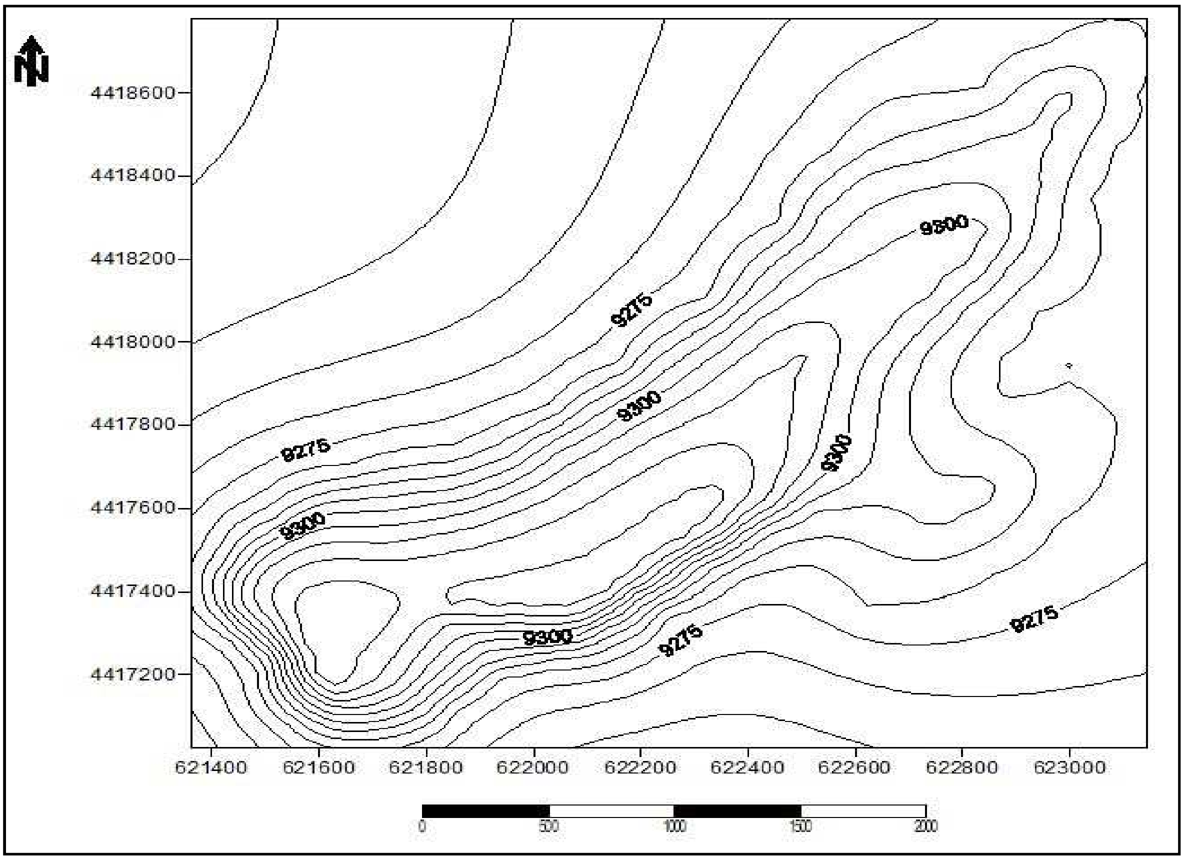

Figure 3.2 Contour Map of Top of Sand Structure of A-1 Reservoir

3.2.2 Estimation of Porosity, Thickness, and Permeability

The reservoir has an aerial extent of about 620 acres with the net thickness of about 40ft. The average effective porosity of the reservoir is 0.22, with permeability ranging from 250 to 300 md.The maximum and minimum values of the x and y coordinates of the properties location were used to estimate the region of stationarity as shown in Table 3.1

Table 3.1: **Values used to define region of stationarity**

X max	621359.554		Y max	4416890.171
X min	623285.703		Y min	4418926.66
Dell X	1926.149		Dell Y	1926.146
No. of Cells	96		No. of Cells	96
Size of each cell along the x-direction	20		Size of each cell along the y-direction	20

Stanford Geostatistical Modeling Software (SGEMS), an open-source computer package for solving problems involving spatially related variables, was employed. Each reservoir property data set was estimated using variogram models, the Ordinary Kriging and Sequential Gaussian Simulation. Generally, anisotropic variograms were considered to adequately capture the spatial correlation between the data points. The properties evaluated are porosity, permeabilities, and net thickness. These properties were evaluated in each of the layers within the reservoir. Four layers were considered in this study.

Ordinary Kriging (OK) was carried out on selected variogram models to estimate permeability, porosity and thickness values at the unsampled location. Sequential Gaussian Simulation (SGS) was carried out on porosity and, thickness, while the Sequential Indicator Simulation was carried out on the permeability model with ten realizations produced in each layer. Philips,(2012) proposed that one realization is only one possible outcome, many realization normally need to be simulated to assess variability and probability of occurrence. The maps generated from Kriging are shown in the figures below.

i) Porosity

Figure 3.3, Figure 3.4, Figure 3.5 and Figure 3.6 show porosity maps generated with ordinary Kriging. Variogram analysis which measures the degree of spatial variation in the data set was conducted on the porosity data set to subsequently aid in the generation of equiprobable realizations. The exponential model was used to fit the data set by visual inspection. The spatial variation in the porosity data points was adequately captured in one variogram direction. Input parameters for the variogram computation and modeling can be seen in Table 3.2 and the results are shown below:

Table 3.2: **Input parameter for variogram computation and modeling**

Parameters		**POROSITY** Layer 1	Layer 2	Layer 3	Layer 4
Number of Lags		60	60	60	60
Lag Separation		45	55	50	55
Lag Tolerance		75	75	75	75
Number of Directions		1	1	1	1
Major Direction/ Omni-directional	Azimuth	0	0	0	0
	Dip	0	0	0	0
	Tolerance	90	90	90	90
	Bandwidth	1200	1200	1200	1200
Nugget Effect		0.35	0.25	0.23	0.17
Number of Structures		1	1	1	1
Sill		0.53	0.54	0.83	0.74
Minimum Range		89	105	110	112
Medium Range		221	216	361	312
Maximum Range		512	678	788	674

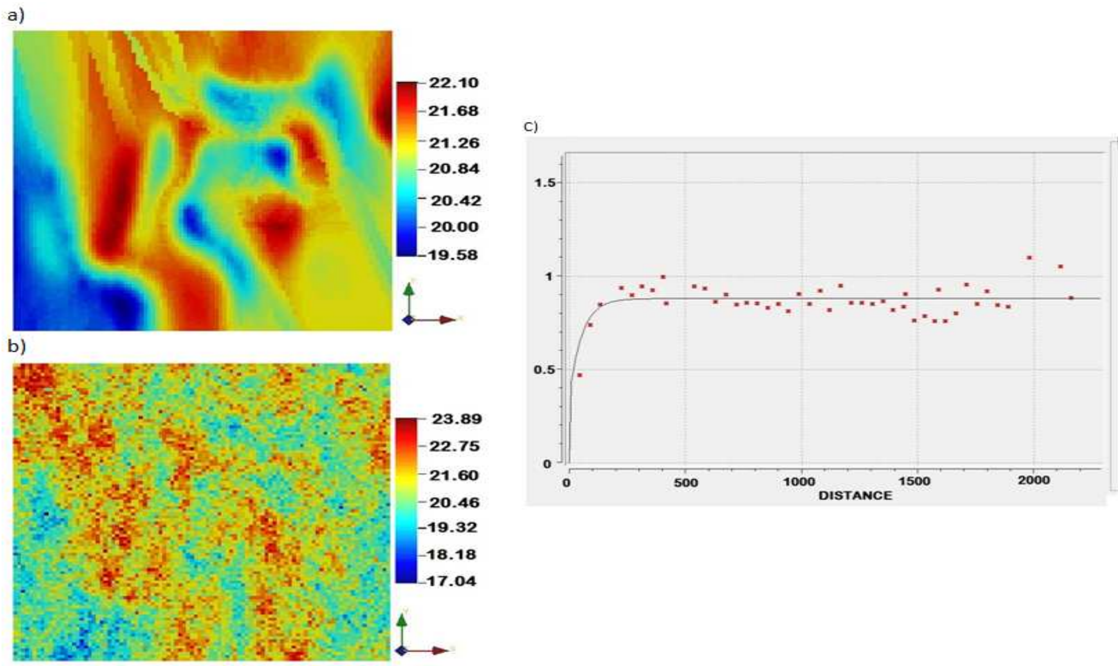

Figure 3.3: Porosity Distribution in Layer 1; a) ordinary kriging b) a plot of sequential gaussian simulation c) variogram model

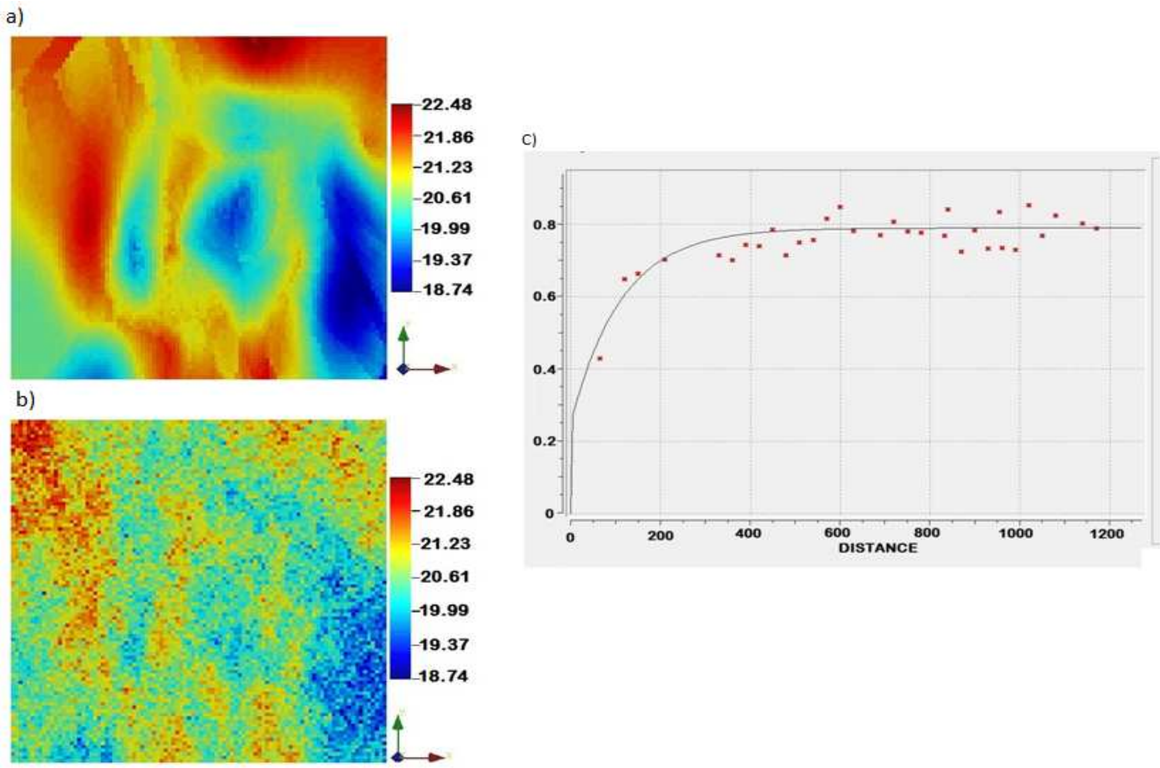

Figure 3.4: Porosity Distribution in Layer 2; a) ordinary kriging b) a plot of sequential gaussian simulation c) variogram model

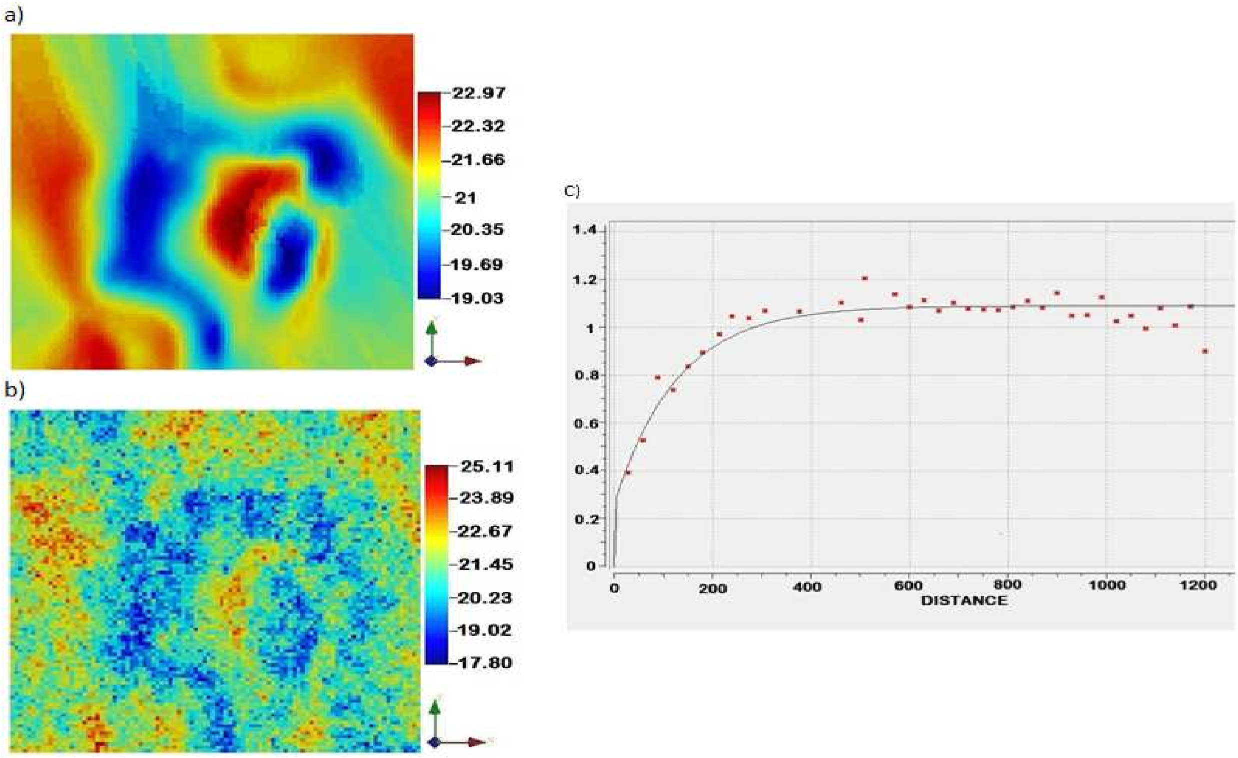

Figure 3.5: Porosity Distribution in Layer 3; a) ordinary kriging b) a plot of sequential gaussian simulation c) variogram model

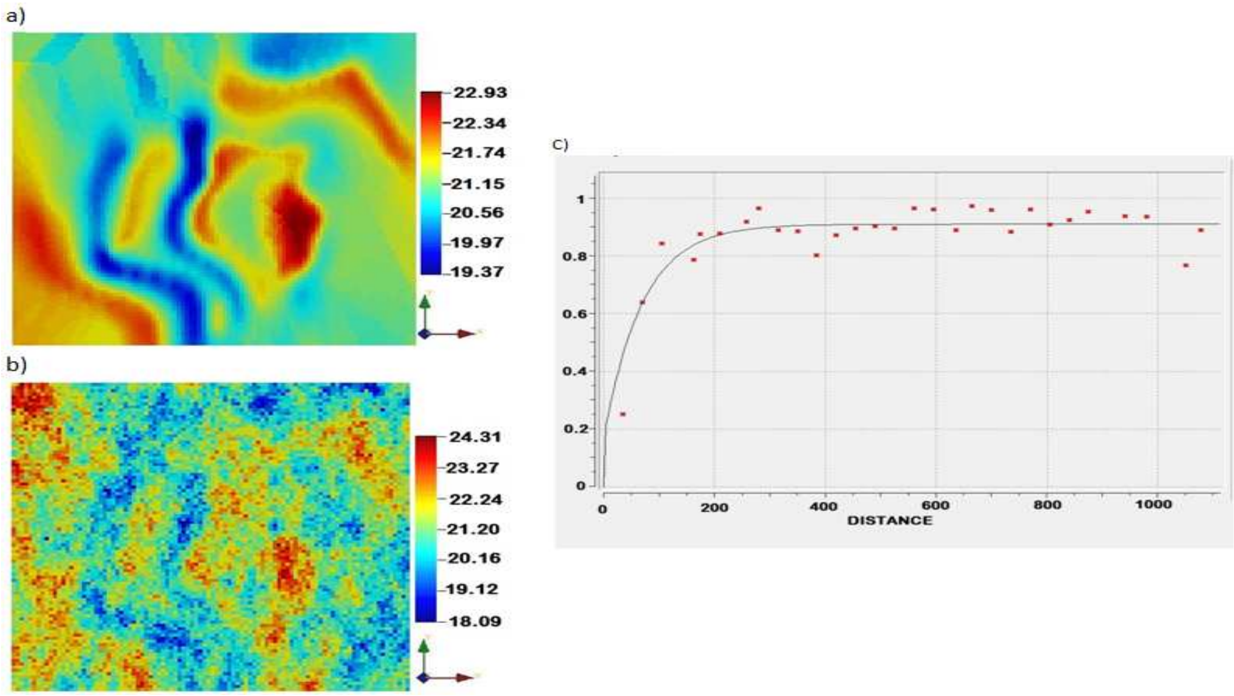

Figure 3.6: Porosity Distribution in layer 4; a) ordinary kriging b) a plot of sequential gaussian simulation c) variogram model

ii) Thickness

Figure 3.7, Figure 3.8, Figure 3.9 and Figure 3.10 show thickness maps generated from ordinary Kriging. The models indicated good spatial continuity from the southeast to the northwest corner of the grid block. This corresponds to the principal direction of the variogram. The estimation variance is relatively low across the entire map.

By visual inspection, the Gaussian variogram model was used to fit the thickness data set from the variogram analysis conducted. Omni-directional variograms were used to adequately capture the spatial correlation in the thickness data set. Input parameters for the variogram computation and modeling can be seen in Table 3.3.

Table 3.3: **Input parameter for variogram computation and modeling**

Parameters		**THICKNESS**			
		Layer 1	**Layer 2**	**Layer 3**	**Layer 4**
Number of Lags		40	40	40	40
Lag Separation		30	30	30	30
Lag Tolerance		80	80	80	80
Number of Directions		1	1	1	1
Major Direction/ Omni-directional	Azimuth	0	0	0	0
	Dip	0	0	0	0
	Tolerance	90	90	90	90
	Bandwidth	6900	6900	6900	6900
Nugget Effect		7.9	11.5	13.3	16.6
Number of Structures		1	1	1	1
Sill		23	15.4	17	18
Minimum Range		150	96	228	288
Medium Range		720	588	684	660
Maximum Range		1320	1116	1080	1200

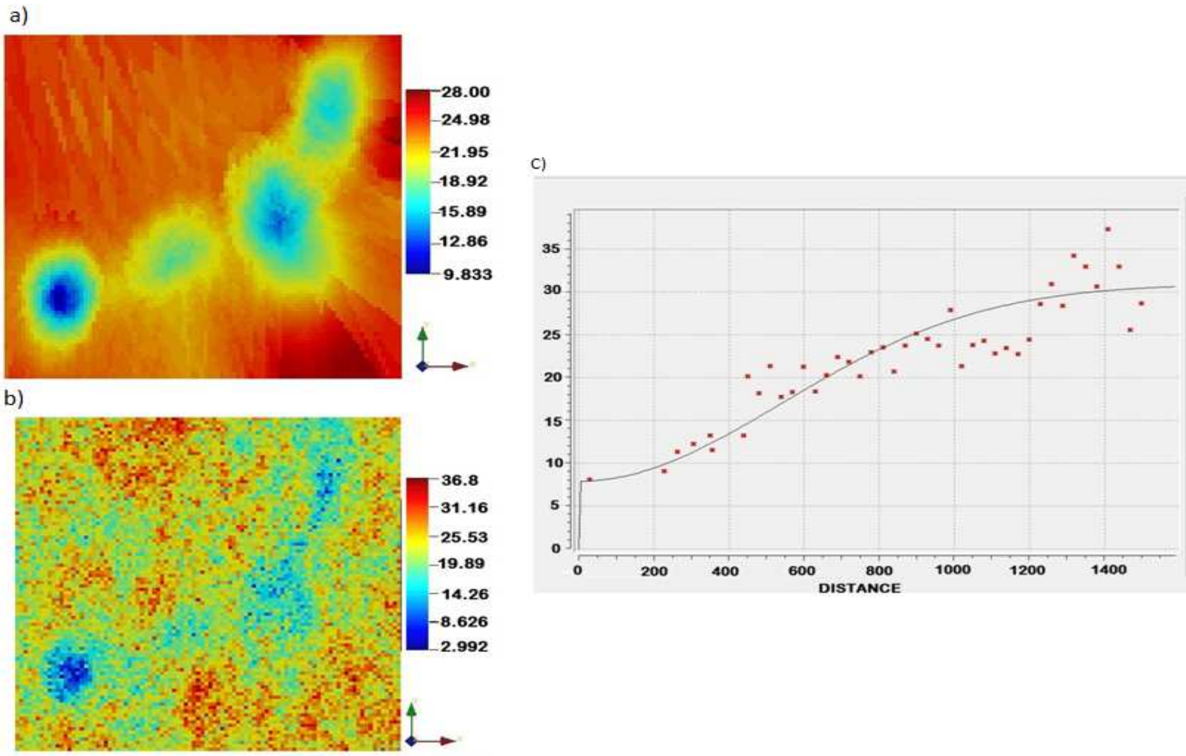

Figure 3.7: Net Thickness Distribution in Layer 1; a) ordinary kriging b) a plot of sequential gaussian simulation c) variogram model

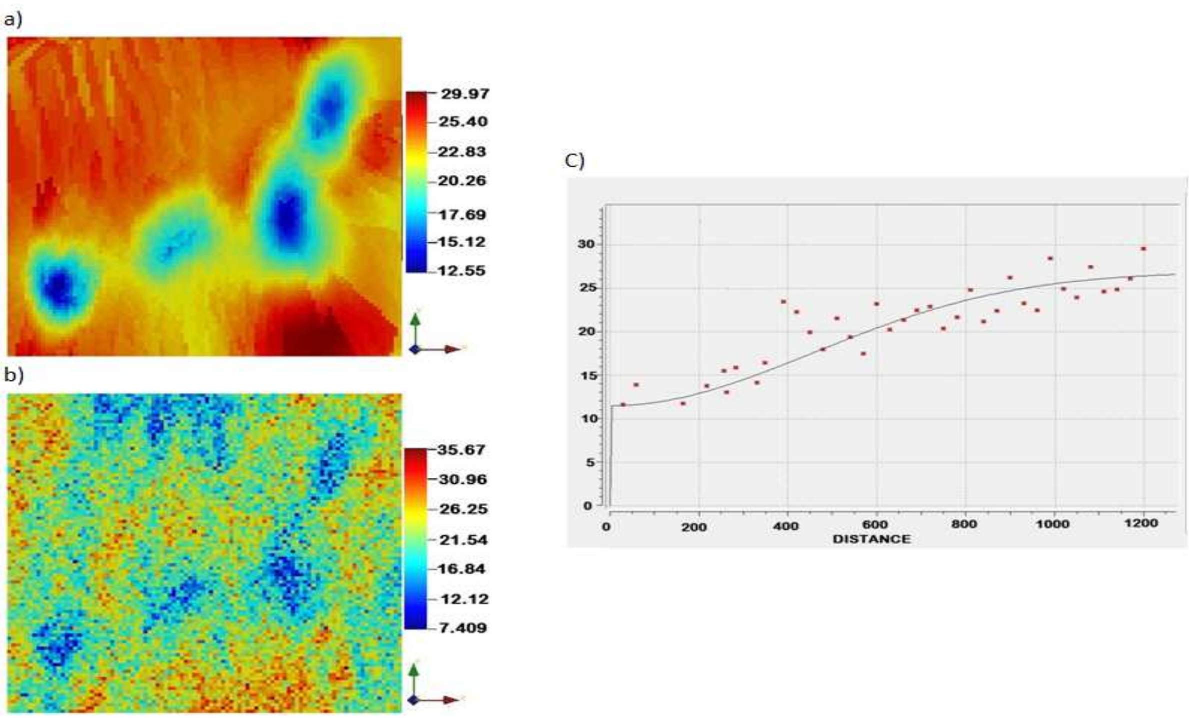

Figure 3.8: Net Thickness Distribution in Layer 2; a) ordinary kriging b) a plot of sequential gaussian simulation c) variogram model

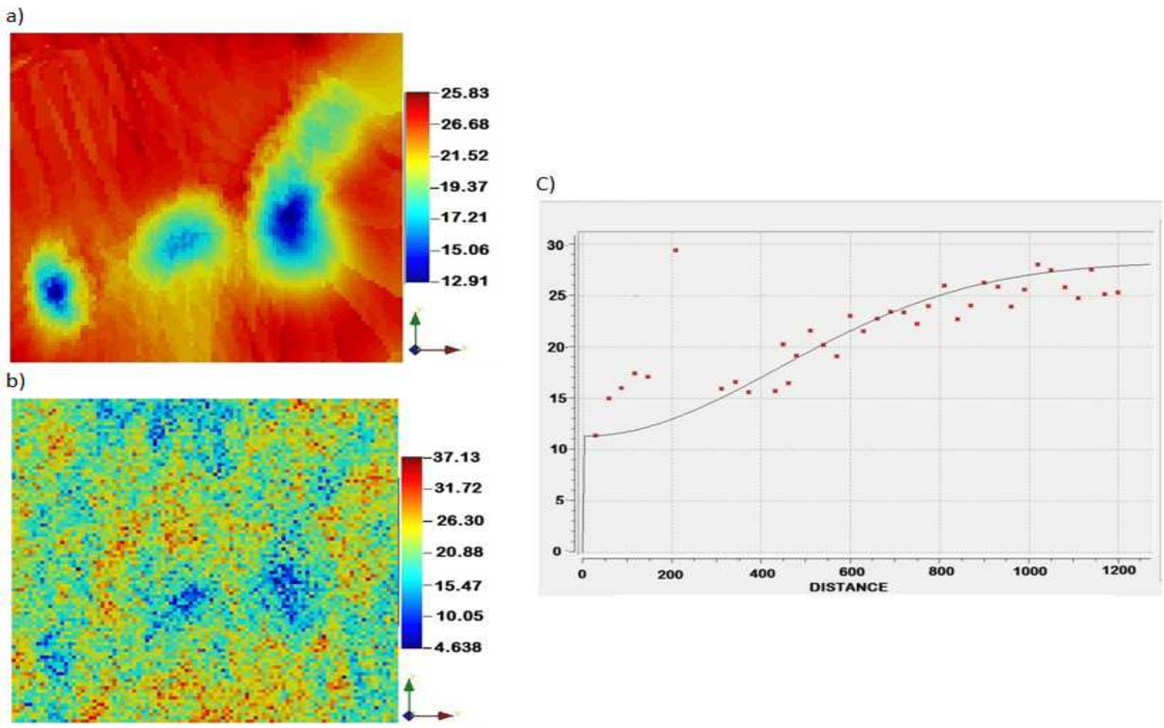

Figure 3.9: Net Thickness Distribution in Layer 2; a) ordinary kriging b) a plot of sequential gaussian simulation c) variogram model

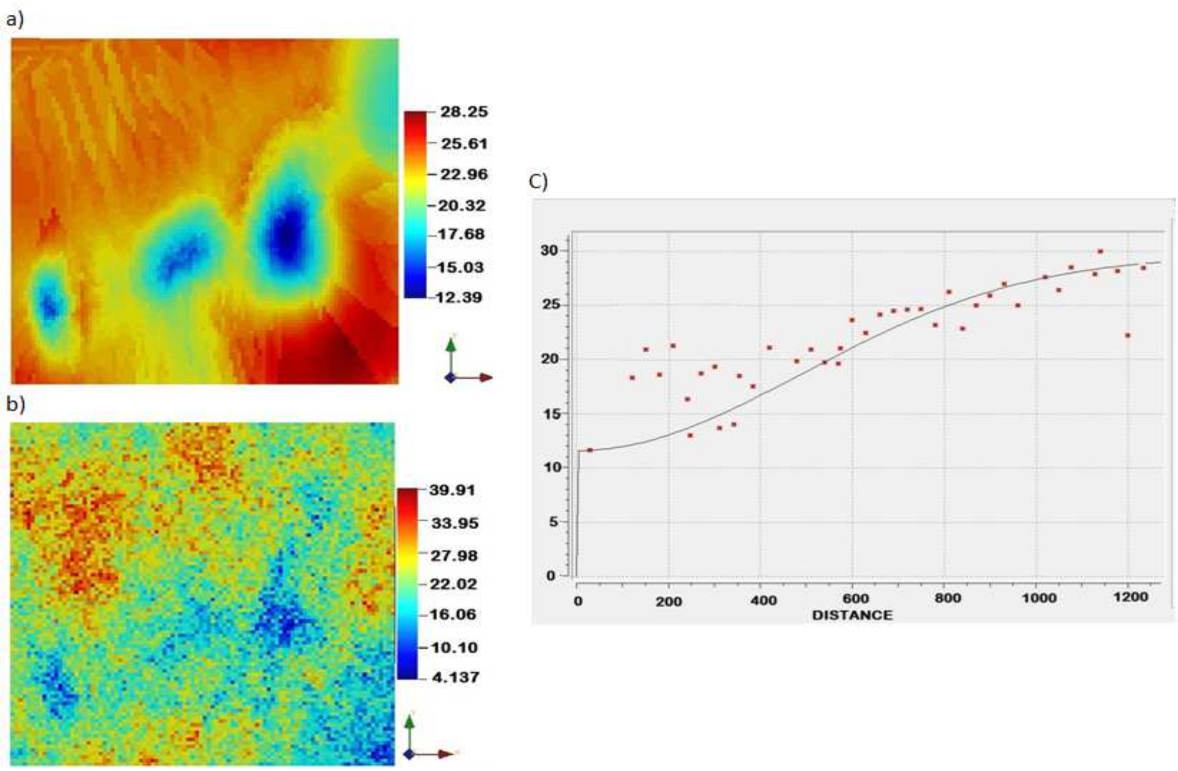

Figure 3.10: Net Thickness Distribution in Layer 4; a) ordinary kriging b) a plot of sequential gaussian simulation c) variogram model

iii) Permeability

The permeability was modeled using a similar procedure as was done for porosity. The results are shown in Figure 3.11, Figure 3.12, Figure 3.13 and Figure 3.14. Input parameters for the variogram computation and modeling can be seen in Table 3.4.

Table 3.4: **Input parameter for variogram computation and modeling**

Parameters		**PERMEABILITY**			
		Layer 1	**Layer 2**	**Layer 3**	**Layer 4**
Number of Lags		50	50	50	50
Lag Separation		60	55	25	30
Lag Tolerance		105	105	105	105
Number of Directions		1	1	1	1
Major Direction/ Omni-directional	Azimuth	0	0	0	0
	Dip	0	0	0	0
	Tolerance	90	90	90	90
	Bandwidth	6900	6900	6900	6900
Nugget Effect		3	30	25	20
Number of Structures		1	1	1	1
Sill		10	75	118	68
Minimum Range		112	89	64	72
Medium Range		310	322	224	212
Maximum Range		588	510	488	529

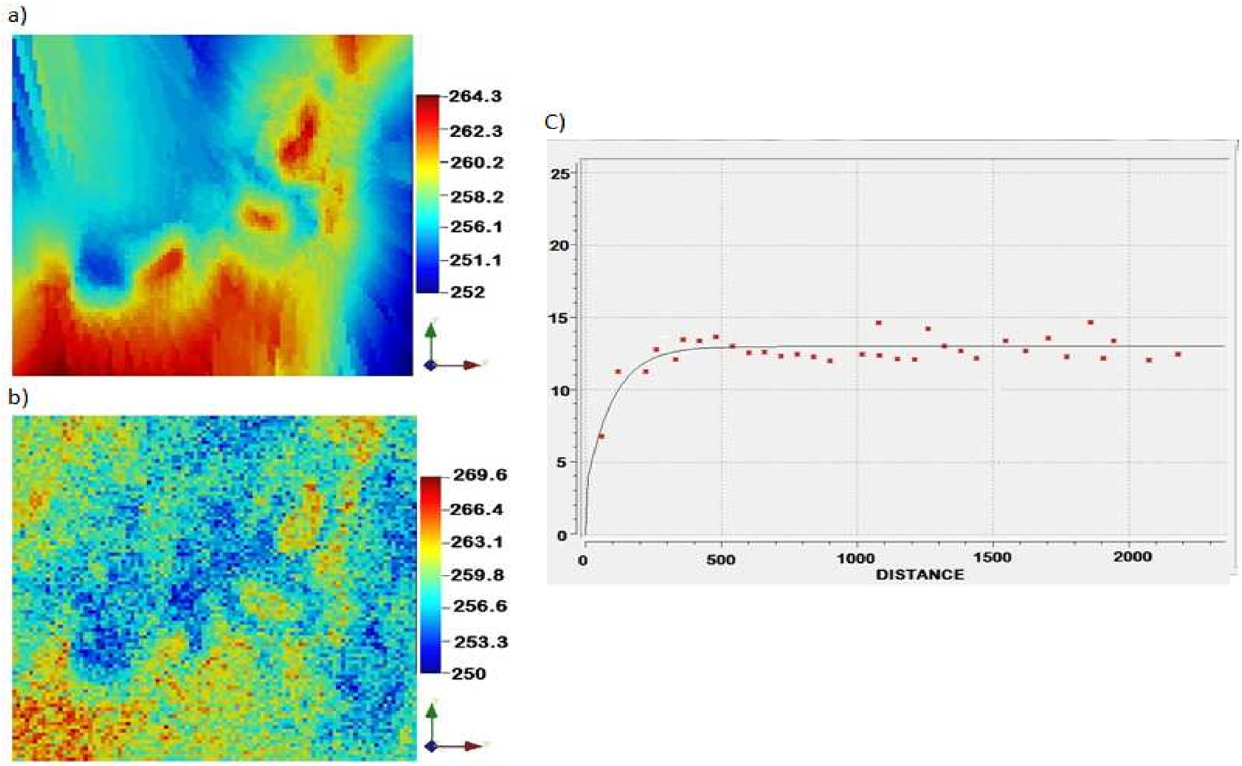

Figure 3.11: Permeability Distribution in Layer 1; a) ordinary kriging b) a plot of sequential indicator simulation c) variogram model

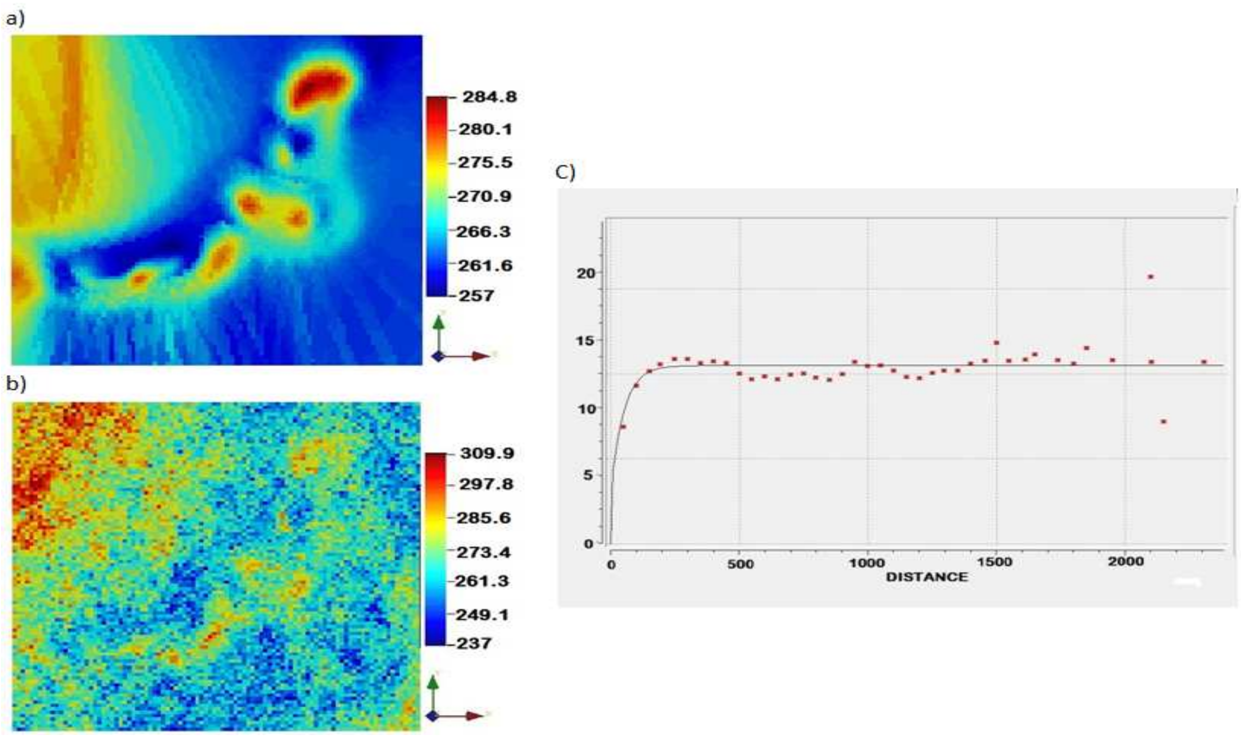

Figure 3.12: Permeability Distribution in Layer 2; a) ordinary kriging b) a plot of sequential indicator simulation c) variogram model

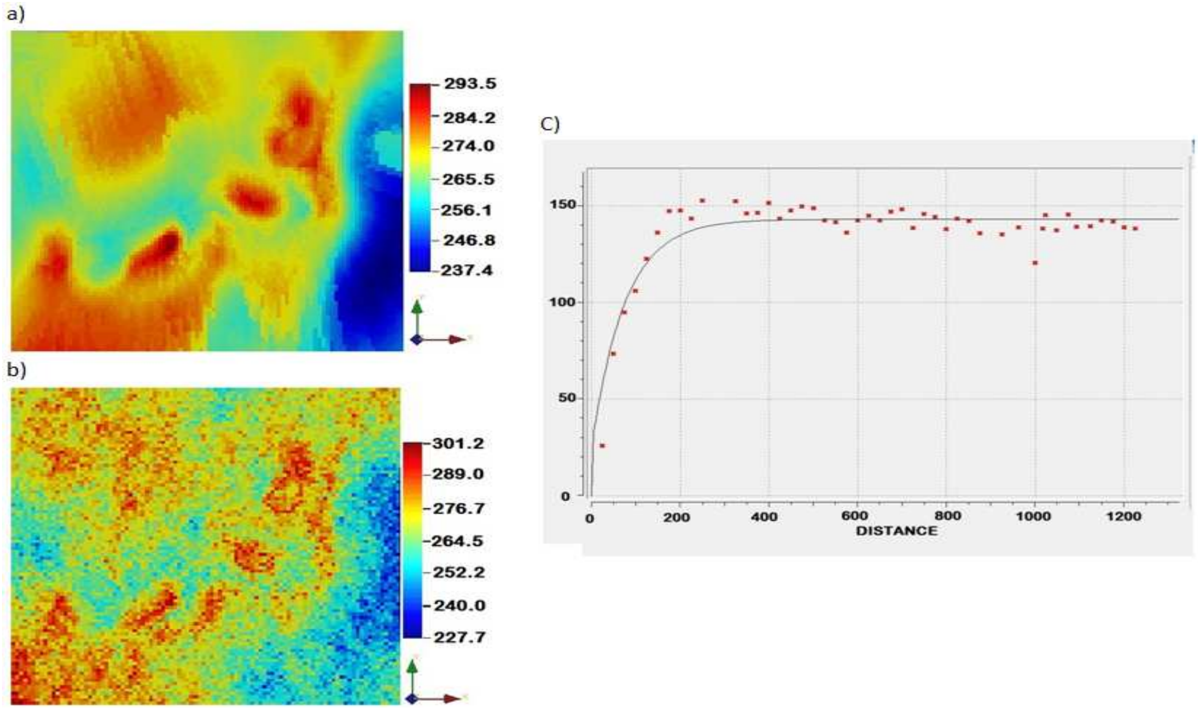

Figure 3.13: Permeability Distribution in Layer 3; a) ordinary kriging b) a plot of sequential indicator simulation c) variogram model

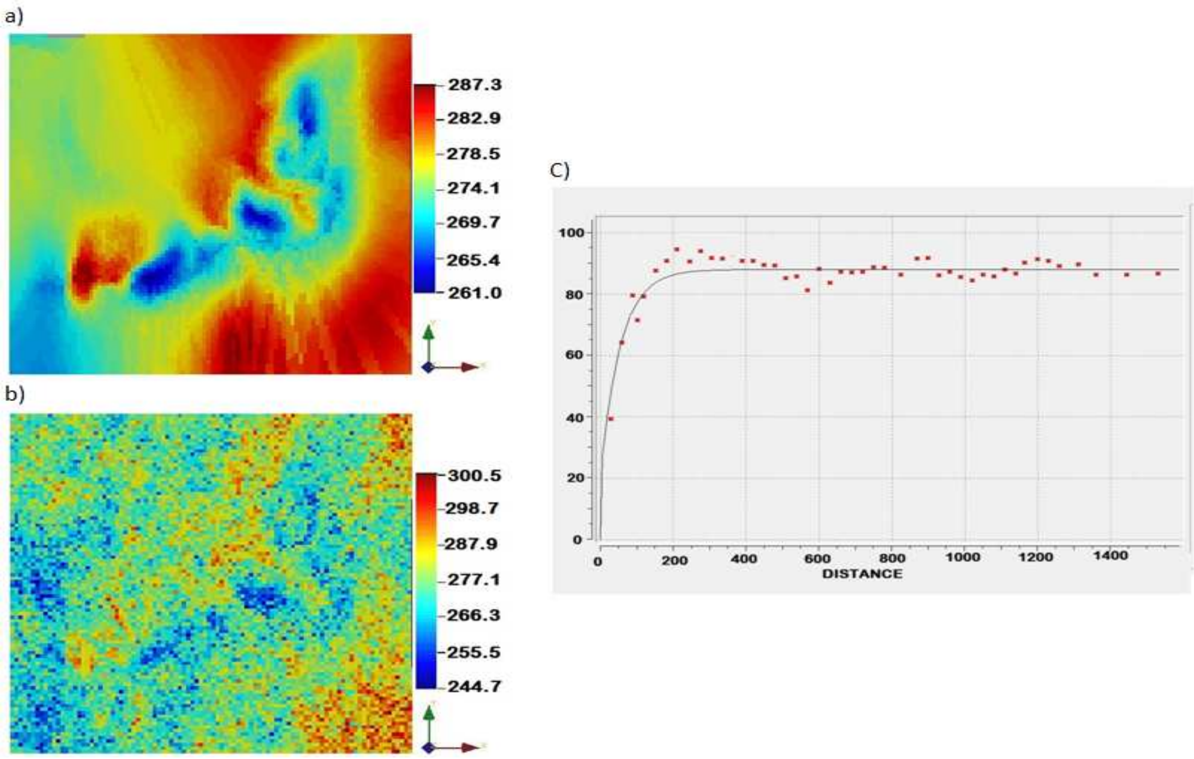

Figure 3.14: Permeability Distribution in Layer 4; a) ordinary kriging b) a plot of sequential indicator simulation c) variogram model

3.2.3 Estimation of Original Oil in Place (OOIP)

The reservoir structure has a maximum elevation difference of approximately 60ft. with a thickness of approximately 40 ft. The average net-pay thickness is 20ft. with a net to gross ratio of 0.5. The original volume of oil in place (OOIP) is calculated from gross thickness and porosity maps generated with ordinary Kriging. The OOIP in a stock tank barrel (STB) for each grid block in the map is given by:

$$\textbf{OOIP} = \frac{\boldsymbol{A * h * ng * \left(\frac{\phi}{100}\right)(1 - Sw)}}{\boldsymbol{5.615 * Bo}} \qquad \text{Equation 3.1}$$

Where

A = the surface area of a block(200 × 200 = 40000ft^2)

h = gross thickness (ft.)

ng = net to gross ratio (0.5)

Φ = porosity (%)

Sw = the water saturation

Bo = formation volume factor (res bbl/stb)

$$\text{OOIP} = \frac{40000 * 9.97 * 0.5 * \left(\frac{18.335}{100}\right) * (1 - 0.23)}{5.615 * 1.2} = 4177.97\,\textbf{STB}$$

$$\text{Total OOIP} = \sum (\text{ OOIP from each cell})$$

Total OOIP was found to be $= 25.90$ **MM STB**

3.2.4 Reservoir Dynamic Modeling

The reservoir simulation phase of this study was carried out with a sensor6K compositional and black-oil reservoir simulator (Coat, 2013). The phases present in the reservoir are water and oil. The model represents a 620 acre field (approximately 6000ft. x 5400ft.) with three production wells located in grid block 7:7:4, 2:3:6 and 9:4:5 respectively. The production period is 10 years with all perforations shut down as soon as water cut reaches 80%. Figure 3.5 shows the initial fluids in place after the initialization run.

Table 3.5: **Initial fluids in place**

REG NAME FIELD	WATER MSTB	OIL MSTB	GAS MMCF	GOR SCF/STB			BO (RB/STB)	BG (RB/MCF)
				1	2	3		
	7524	25871	0	0	0	0	1.175	0

The simulation grid and various rock properties in each grid cell are specified in the grid section. From these properties, the pore volumes of the grid blocks and the inter-block transmissibilities are calculated by the simulator. The average effective porosity is 0.22 and a permeability range from 250 to 300 md. The relative permeability curve used is shown in Figure 3.7 below. A summary of the reservoir properties is shown in Table 3.5.

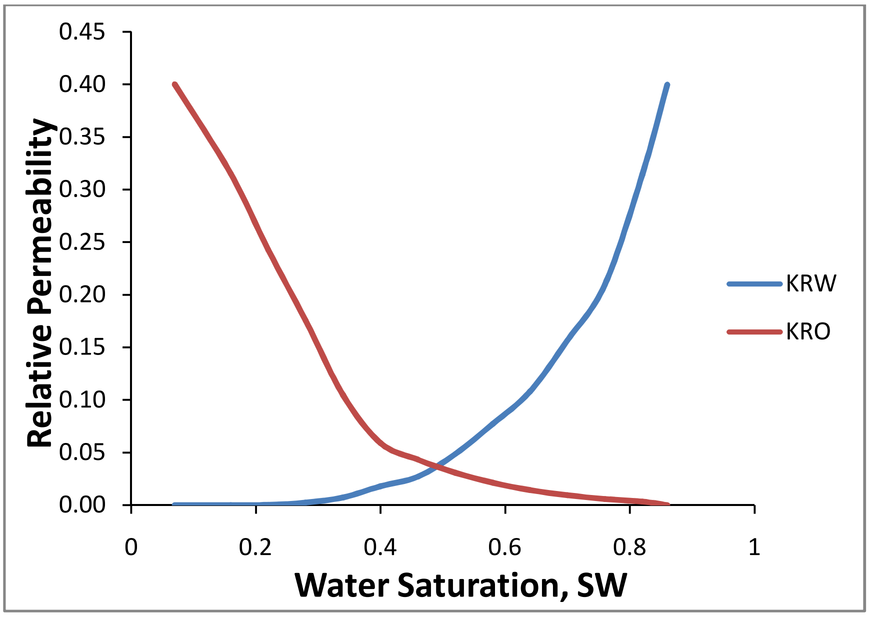

Figure 3.15: Relative Permeability Curve

Table 3.5: **Reservoir Properties**

Reservoir area	620 acres
Grid block size	200ft x 200ft x 6ft
Top of Reservoir	9290 ft
Water Oil Contact	9330 ft
Reservoir thickness	40 ft
Average Porosity	0.22
Initial Oil Saturation	0.77
Initial Water Saturation	0.23
Oil Viscosity	2.4 cp
Water Viscosity	0.96 cp
Oil FVF (Bo)	1.175rb/stb
Water FVF (Bw)	1.00325 rb/stb
Oil Density	49.011 lb/cuft
Water Density	62.140 lb/cuft
Water Compressibility	3 x 10-6 psi-1
Rock Compressibility	3 x 10-6 psi-1
Initial Reservoir Pressure	4800 Psi
Bubble Point Pressure	3000 Psi

Figure 3.16 to Figure 3.23 show the map of initial pressure, water and oil saturation for each layer of the reservoir.

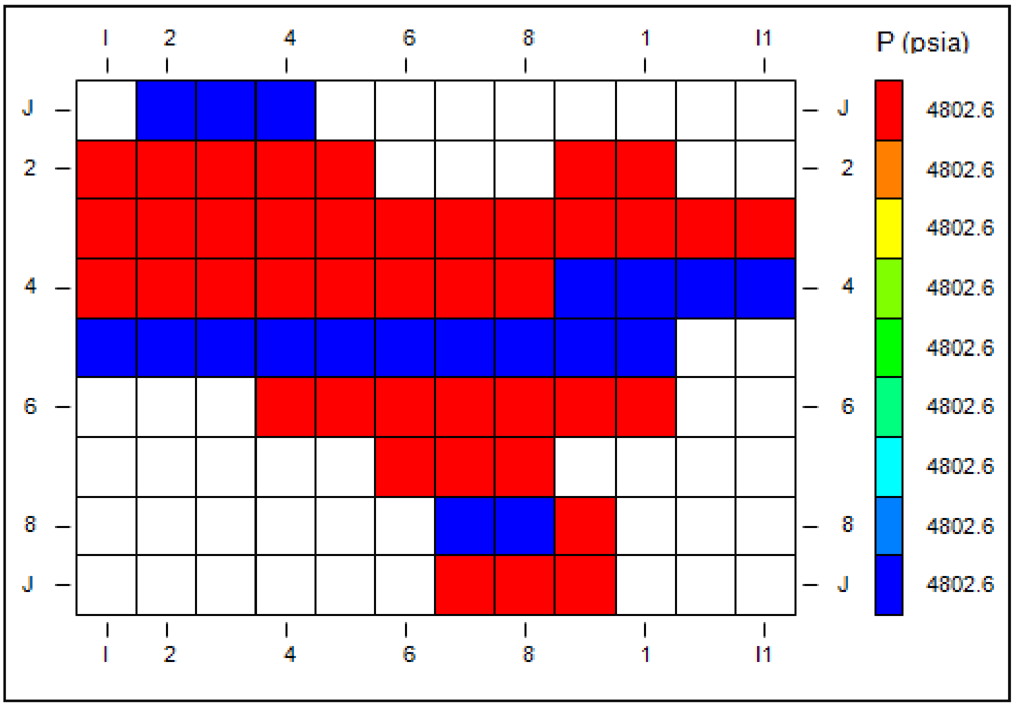

Figure 3.16:Layer 1; map of initial pressure

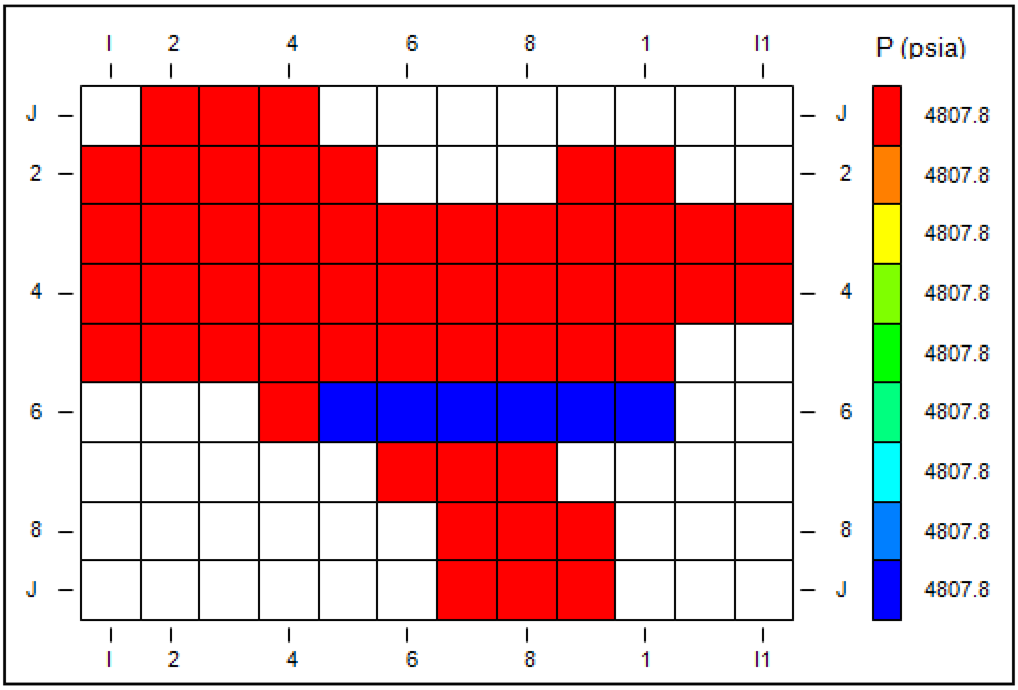

Figure 3.17:Layer 2; map of initial pressure

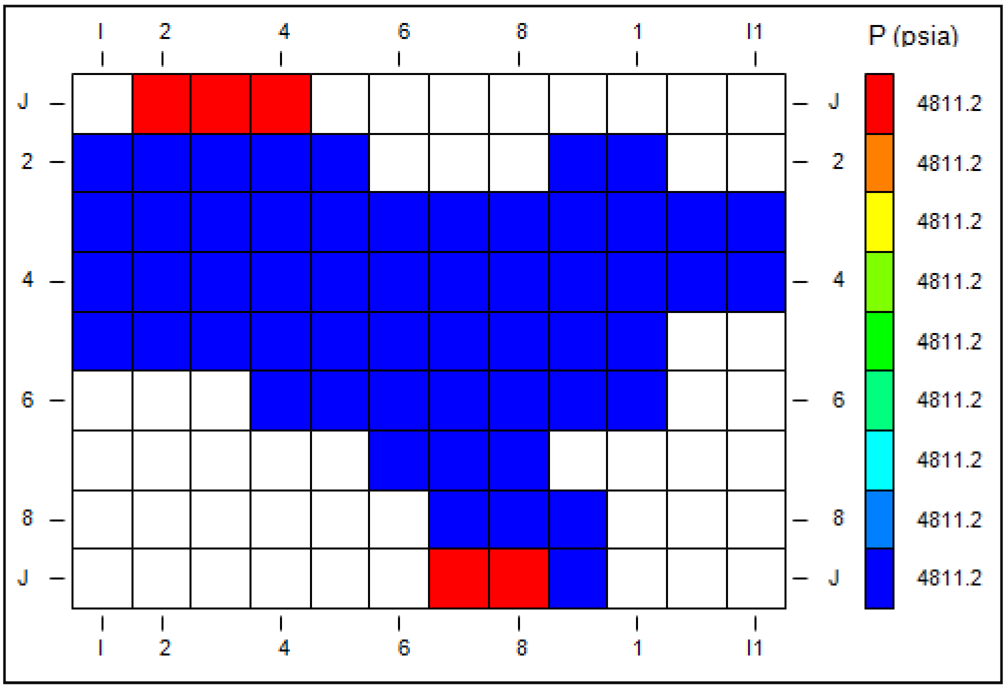

Figure 3.18:Layer 3; map of initial pressure

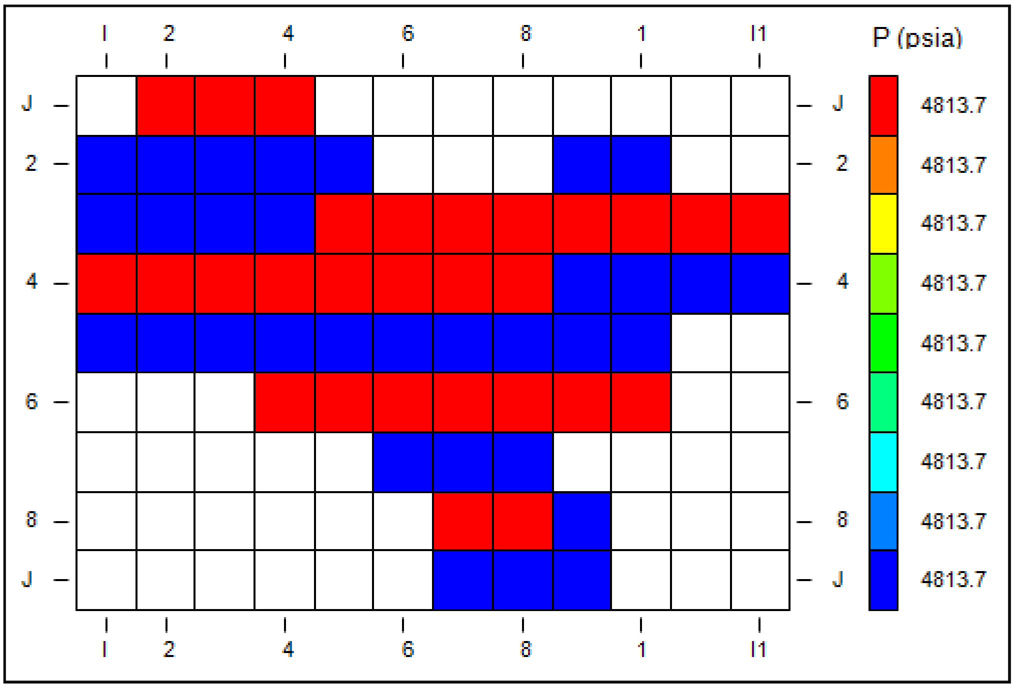

Figure 3.19:Layer 4; map of initial pressure

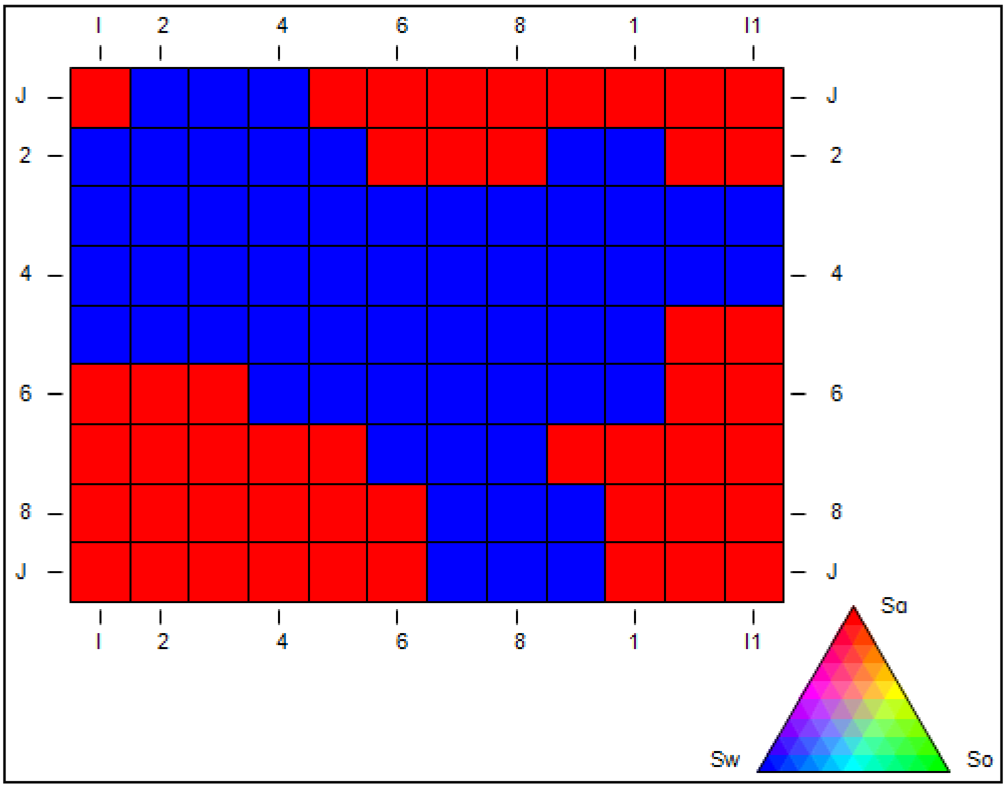

Figure 3.20:Layer 1; map of initial water and oil saturation

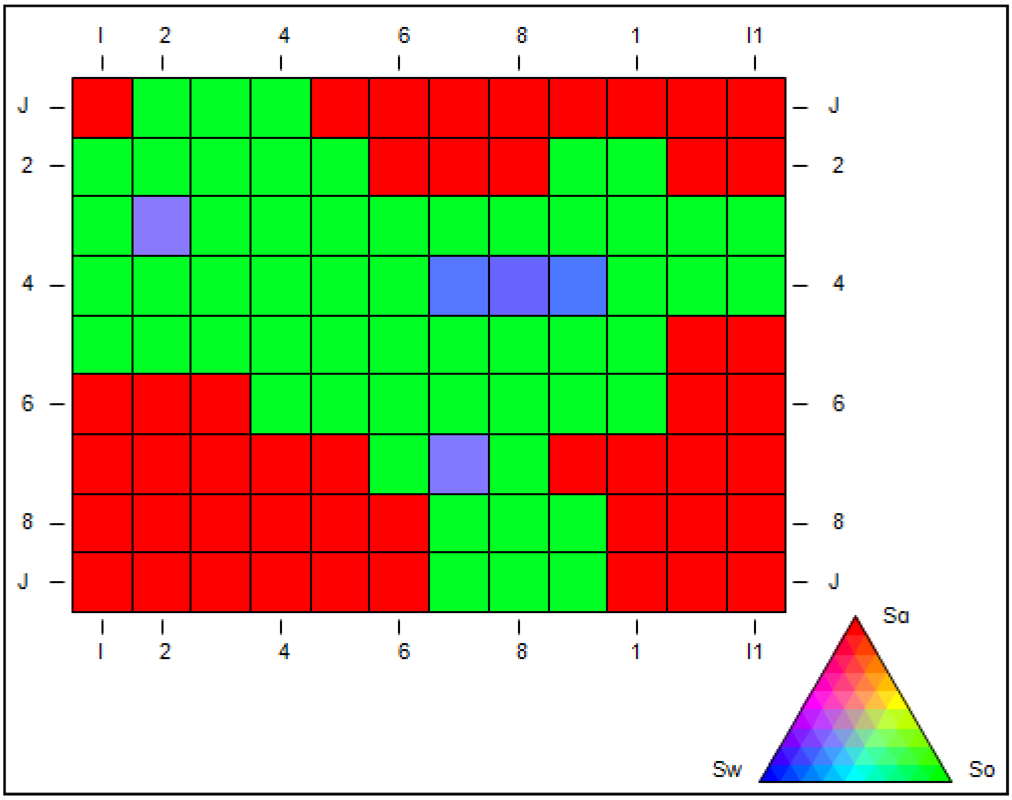

Figure 3.21:Layer 2; map of initial water and oil saturation

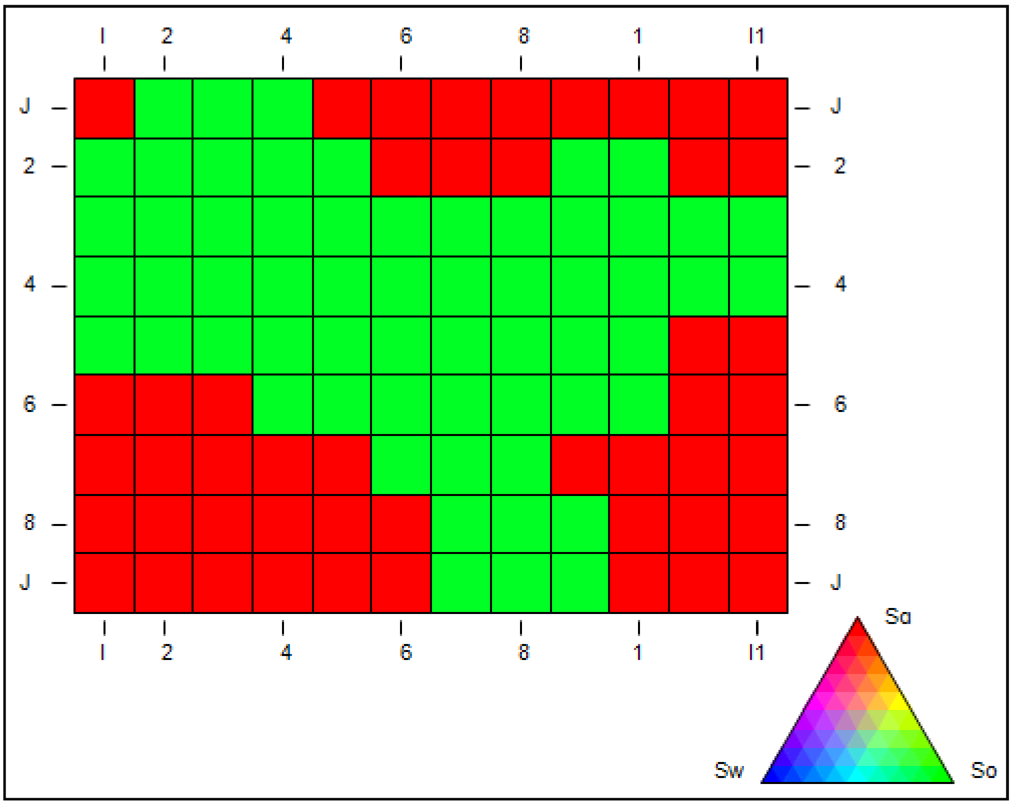

Figure 3.22:Layer 3; map of initial water and oil saturation

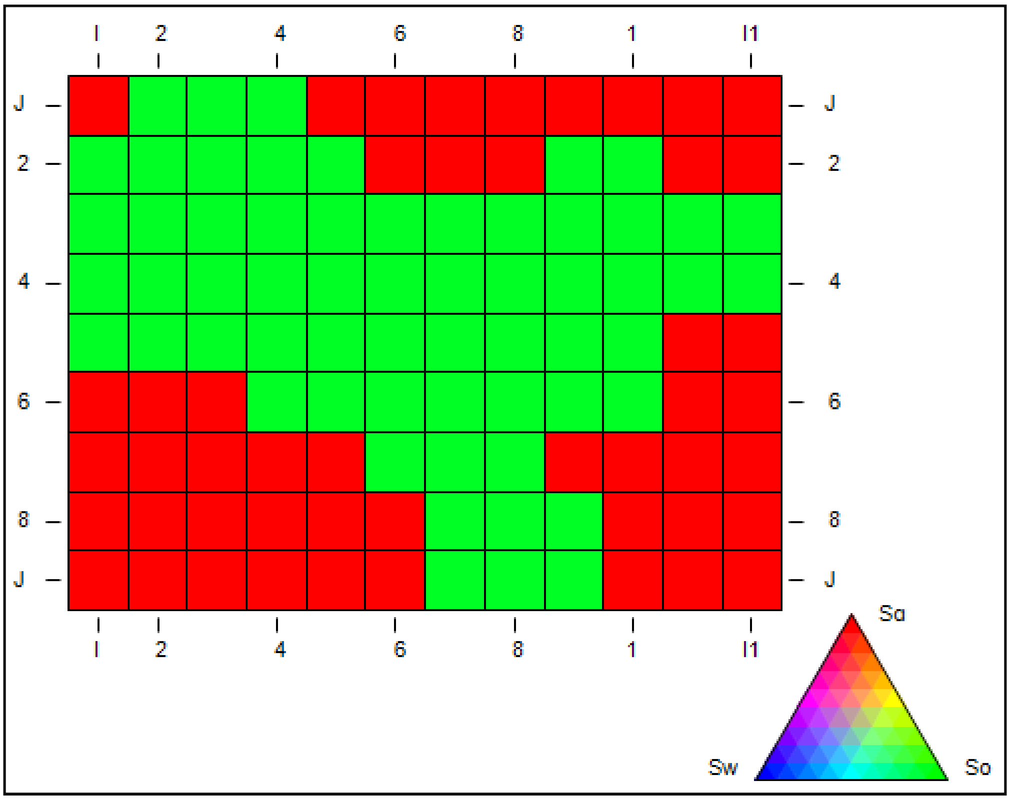

Figure 3.23:Layer 4; map of initial water and oil saturation

CHAPTER 4

RESULTS AND DISCUSSION

4.1 Introduction

Well placement was considered to be the key driver adopted to improve the performance of the reservoir modeled in this study with the purpose of maximizing the economic profitability of the green field. In respect of this, certain well and reservoir parameters such as, horizontal well length, vertical and horizontal permeabilities were varied to ascertain optimum hydrocarbon recovery. The critical evaluation of development strategies implemented to produce the greatest amount of hydrocarbons is described as follows:

4.1.1 **Case 1**: Variation of a Horizontal Well Length

The first scenario considered was producing the reservoir with a horizontal well drilled at varying lengths of 1500ft, 2000ft and 3000ft. The simulator was run for 10 years. The results of the oil rate produced versus time are shown in Figure 4.1; the cumulative oil production is shown in Figure 4.2.

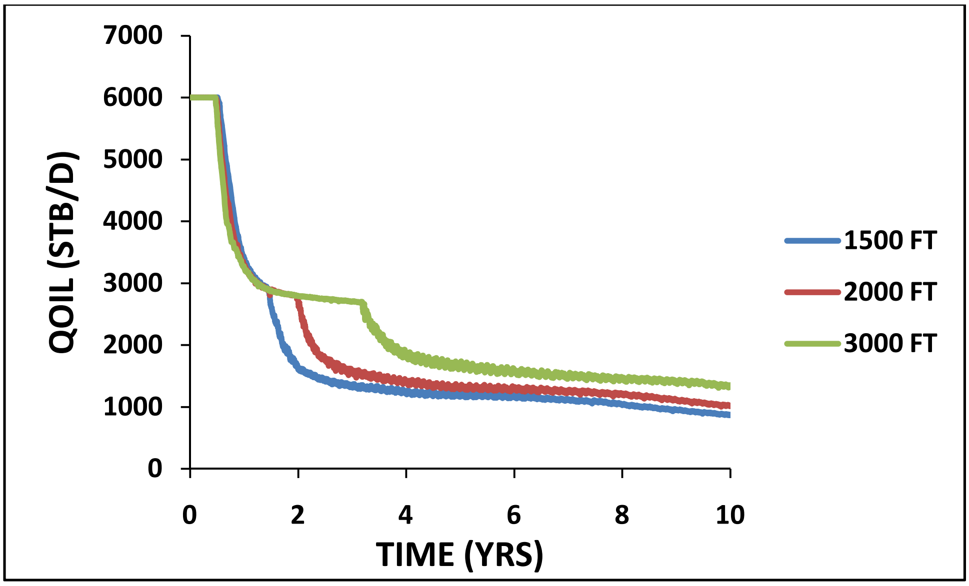

Figure 4.1: Case 1: oil production rate

It can be observed from the results shown in Figure 4.2 that the cumulative oil production is the same for all three horizontal well lengths for the first two years of reservoir operations. After the second year, the horizontal well drilled to a length of 3000 ft. achieved the highest cumulative oil production followed by the horizontalwell length of 2000 ft. and 1500 ft., respectively.

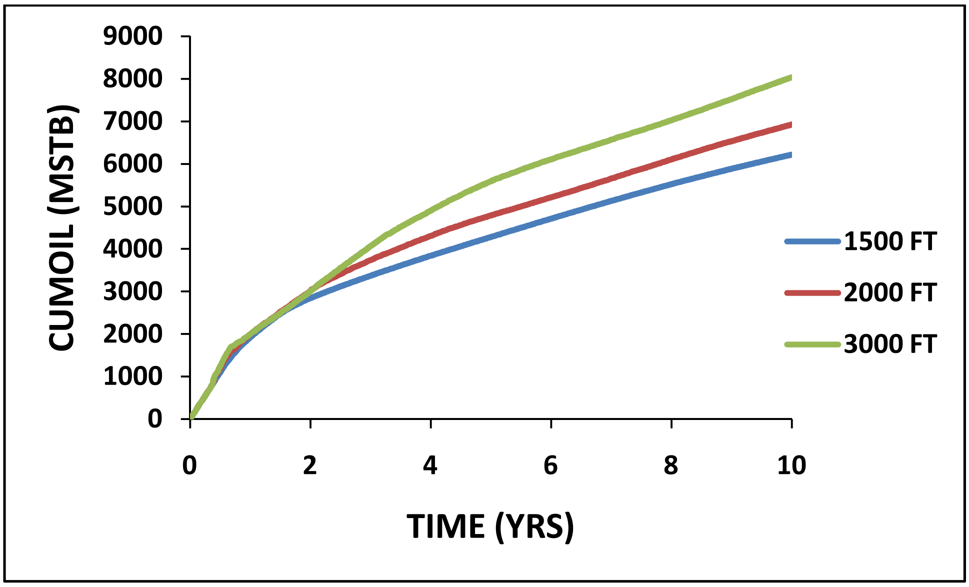

Figure 4.2: Case 1 cumulative oil production

Figure 4.3 shows a graph of water cut versus time. In general, the rate of water production from the reservoir was extremely low this is because horizontal wells were drilled and perforated away from the water zone. However, at a horizontal well length of 1500 ft. the highest water production was observed followed by 2000 ft. and 3000 ft. horizontal well.

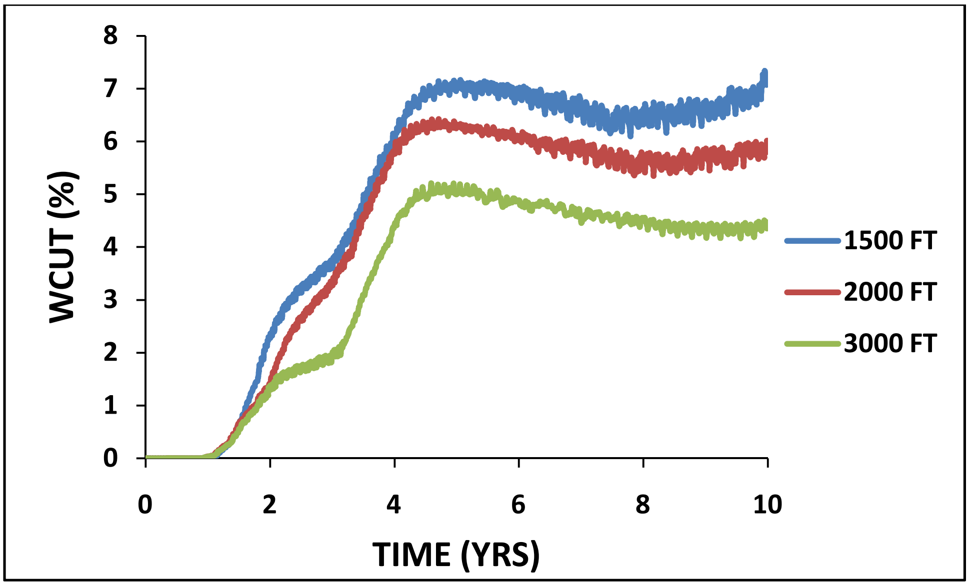

Figure 4.3: Case 1 water cut

Figure 4.4 shows a graph of field pressure versus time. The trend of the field pressures is the same for all three horizontal well lengths. The graph shows no significant variation in the field pressure. At 3010 psi, the field pressure remained constant till the end of the production period, year 10. This is due to the presence of a strong aquifer which provided enough pressure support.

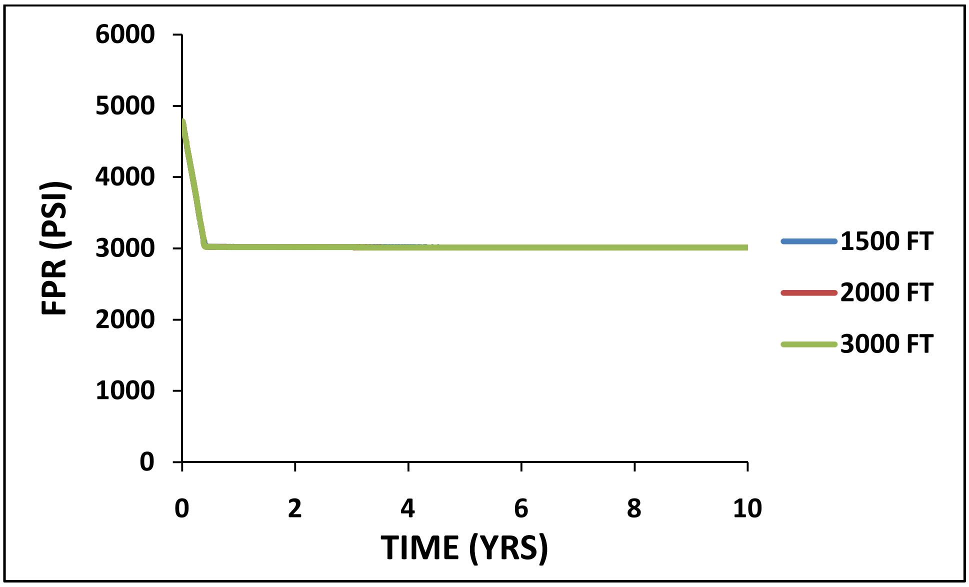

Figure 4.4: Case 3 field pressure

4.1.2 **Case 2**: Variation of Kv/Kh

The second scenario considered was producing the reservoir with the ratio of vertical to horizontal permeability (kv/kh) varied at 0.1, 0.2, 0.4 and 0.55. A horizontal well was drilled at a length of 3000 ft. and the simulator was run for 10 years. The results of the oil rate produced versus time are shown in Figure 4.5; the cumulative oil production is shown in Figure 4.6.

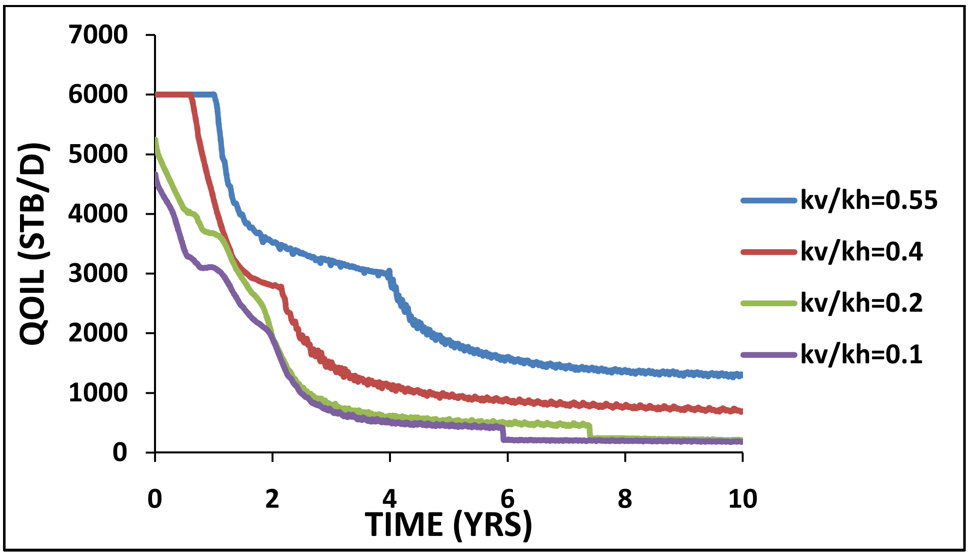

Figure 4.5: Case 2 oil production rate

An increase in field cumulative oil production can be observed from Figure 4.6 as the kv/kh ratio increases. A kv/kh ratio of 0.55 shows the highest cumulative oil production while kv/kh ratio of 0.1 shows the lowest field cumulative oil production at the end of the production period. This is because a lower kv/kh ratio minimizes the vertical cross flow of hydrocarbon between the layers of the reservoir.

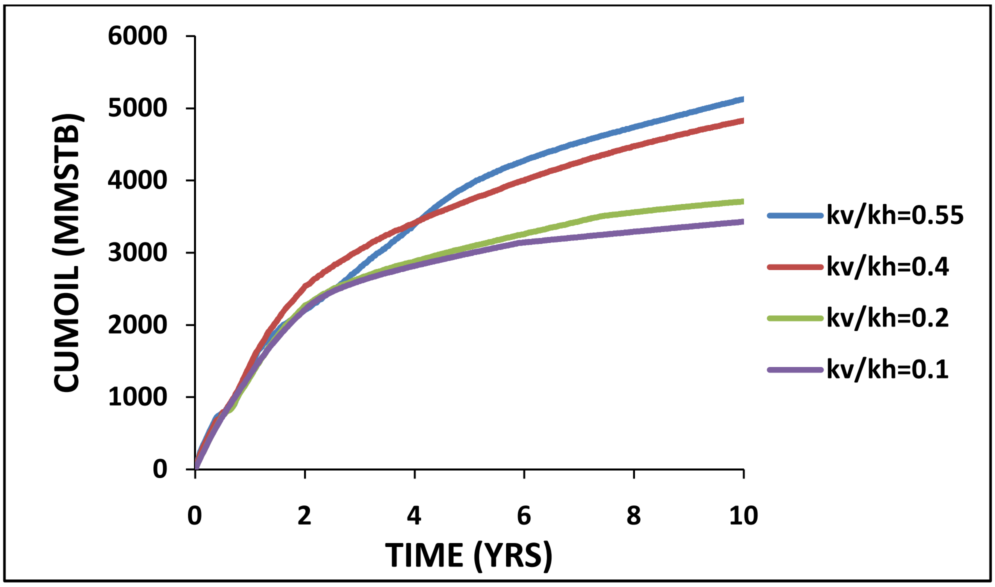

Figure 4.6: Case 2 cumulative oil production

Figure 4.7 shows a graph of water cut versus time. It can be observed from the graph that an early water breakthrough began at kv/kh ratio of 0.55 while late a water breakthrough began at a kv/kh ratio of 0.1.

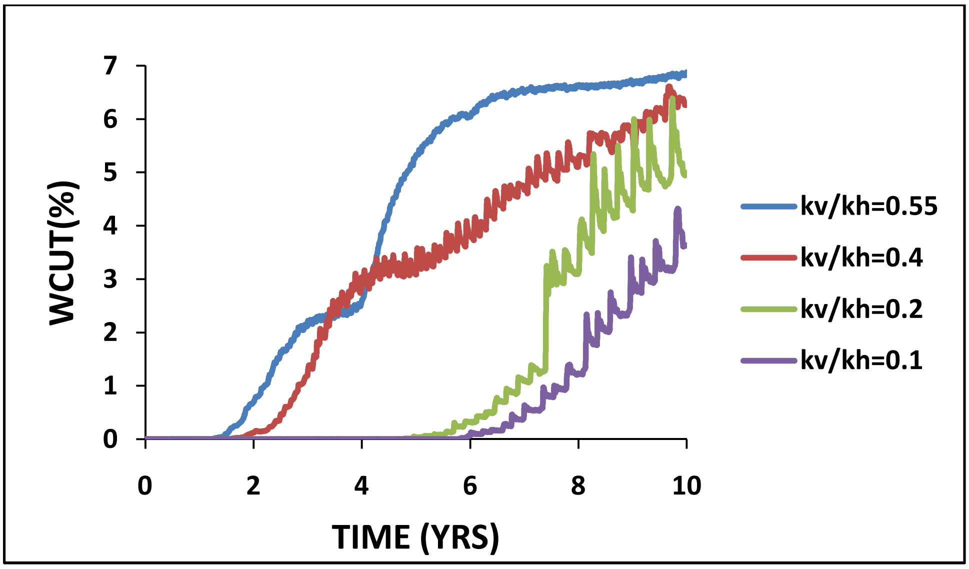

Figure 4.7: Case 2 water cut

CHAPTER 5

CONCLUSION AND RECOMMENDATION

5.1 Conclusion

The study demonstrated an approach to well placement in order to maximize production in a green field. The impact of varying well and reservoir parameters, i.e., horizontal well length and kv/kh, on hydrocarbon recovery was evaluated in this study. Based on the above analysis, the following conclusions can be made:

- The horizontal well length significantly affects the cumulative oil production of a petroleum reservoir. The results of the analysis indicated that a 3000 ft. long horizontal well produced the highest cumulative oil production as compared with that of 2000 ft. and 1500 ft.

- Furthermore, the variation of vertical to horizontal permeability anisotropy ratio (kv/kh) showed a tremendous improvement in cumulative oil production. From the analysis above, it was observed that the higher the kv/kh ratio the greater the cumulative oil production. At a kv/kh value of 0.55, a higher cumulative oil production was observed compared to a kv/kh ratio of 0.4, 0.2 and 0.1.

5.2 Recommendation

This project recommends that further research be carried out on different well placement approaches such as the angle of orientation and the azimuth for the drilling of the horizontal well.

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APPENDIX

APPENDIX A: NOMENCLATURE

A = Area

h = Thickness

φ = Porosity

k = Permeability

μ = Viscosity

Bo = Oil Formation Volume Factor

Sw = Water Saturation

Swi = Initial Water Saturation

Soi = Initial Oil Saturation

ng = Net to Gross Ratio

Az = Azimuth

kv = Vertical Permeability

kh = Horizontal Permeability

SGS = Sequential Gaussian Simulation

OK = Ordinary Kriging

OOIP = Original Oil in Place

STOOIP = Stock Tank of Original Oil in Place

STB = Stock Tank Barrel