ESTIMATION OF EXPECTED MONETARY VALUES OF SELECTED TURKISH OIL FIELDS USING TWO DIFFERENT RISK ASSESSMENT METHODS

A THESIS SUBMITTED TO
THE GRADUATE SCHOOL OF NATURAL AND APPLIED SCIENCES
OF
THE MIDDLE EAST TECHNICAL UNIVERSITY

BY

EGEMEN KAYA

IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE DEGREE OF
MASTER OF SCIENCE
IN
THE DEPARTMENT OF PETROLEUM AND NATURAL GAS ENGINEERING

DECEMBER 2003

Approval of the Graduate School of Natural and Applied Sciences.

Prof. Dr. Canan Özgen
Director

I certify that this thesis satisfies all the requirements as a thesis for the degree of Master of Science.

Prof. Dr. Birol DEMİRAL
Head of Department

This is to certify that we have read this thesis and that in our opinion it is fully adequate, in scope and quality, as a thesis for the degree of Master of Science.

Assoc. Prof. Dr. Serhat Akın
Co-Supervisor

Prof. Dr. Mustafa V. KÖK
Supervisor

Examining Committee Members

Prof. Dr. Birol Demiral (Chairman)

Prof. Dr. Suat Bağcı

Prof. Dr. Mustafa V. KÖK

Assoc. Prof. Dr. Serhat Akın

MSc. Kubilay Kumsal

ABSTRACT

ESTIMATION OF EXPECTED MONETARY VALUES OF SELECTED TURKISH OIL FIELDS USING TWO DIFFERENT RISK ASSESSMENT METHODS

Kaya, Egemen
M.S., Department of Petroleum and Natural Gas Engineering

Supervisor: Prof. Dr. Mustafa V. Kök
Co-Supervisor: Assoc. Prof. Serhat Akın

December 2003, 77 pages

Most investments in the oil and gas industry involve considerable risk with a wide range of potential outcomes for a particular project. However, many economic evaluations are based on the "most likely" results of variables that could be expected without sufficient consideration given to other possible outcomes and it is well known that initial estimates of all these variables have uncertainty. The data is usually obtained during drilling of the initial oil well and the sources are geophysical (seismic surveys) for formation depths and areal extent of the reservoir trap, well logs for formation tops and bottoms, formation porosity, water saturation and possible permeable strata, core analysis for porosity and saturation data and DST (Drill-Stem Test) for possible oil production rates and samples for PVT (Pressure Volume Temperature) analysis to obtain FVF (Formation Volume Factor) and others. The question is how certain are the values of these variables and what is the probability of these values to occur in the reservoir to evaluate the possible risks. One of the most highly appreciable applications of the risk assessment is the estimation of volumetric reserves of hydrocarbon reservoirs. Monte Carlo and moment technique consider entire ranges of the variables of Original Oil in Place (OOIP) formula rather than deterministic figures. In the present work, predictions were made about how statistical distribution and descriptive statistics of porosity, thickness, area, water saturation, recovery factor, and oil formation volume factor affect the simulated OOIP values. The current work presents the case of two different oil fields in Turkey. It was found that both techniques produce similar results for 95%. The difference between estimated values increases as the percentages decrease from 50% and 5% probability.

Keywords: Drill-Stem Test (DST), Pressure Volume Temperature (PVT), Formation Volume Factor (FVF), Original Oil In Place (OOIP)

ÖZ

İKİ FARKLI RİSK ANALİZ METODU KULLANILARAK SEÇİLMİŞ TÜRK PETROL SAHALARININ BEKLENEN PARASAL DEĞERLERİNİN HESAPLANMASI

Kaya, Egemen
Yüksek Lisans, Petrol ve Doğalgaz Mühendisliği Bölümü

Tez Yöneticisi: Prof. Dr. Mustafa V. Kök
Ortak Tez Yöneticisi: Doç. Dr. Serhat Akın

Aralık 2003, 77 sayfa

Hampetrol ve gaz endüstrisinde çoğu yatırımlar, belirli projelerin geniş çalışma alanları içinde önemli risklerini içerir. Fakat, birçok ekonomik değerlendirme, değişkenlerin diğer olası sonuçlarına yeterli önem verilmeden "en muhtemel" sonuç baz alınarak yapılır ve bilindiği gibi bu değişkenlerin başlangıçtaki tahminlerinde belirsizlik söz konusudur. Veriler, ilk petrol kuyusunun sondajı sırasında elde edilir ve kaynak olarak formasyon derinlikleri ile, rezervuar kapanının alansal büyüklüğü için jeofizik (sismik incelemeler), formasyon üst ve alt sınırları, formasyon gözenekliliği, su doygunluğu ve katmanların olası geçirgenliği için kuyu logları, gözeneklilik, su doygunluğu için core analizleri, olası hampetrol üretim debisi için DST (Dril-Stem Test) ve FHF (Formasyon Hacim Katsayısı) için PVT (Basınç Hacim Sıcaklık) numuneleri kullanılır. Değerlendirmedeki asıl soru, olası riskleri değerlendirmek için değişkenlerin ne kadar doğru olduğu ve değerlerin gerçek rezervuar özelliklerini yansıtma olasılığıdır. Risk kontrolünün en kayda değer uygulamalarından biri de rezeruardaki hidrokarbon rezervlerinin tahminidir. Monte Carlo ve moment tekniği, kararlaştırılmış şekiller haricinde yerinde petrol miktarı (OOIP) formülünün değişkenlerini hesaba katar. Bu çalışmada, gözeneklilik, kalınlık, su doygunluğu, kurtarım faktörü ve hampetrol formasyon hacim katsayısı değerlerinin tanımlayıcı istatistiklerinin ve istatistiksel dağılımlarının, yerinde petrol rezervlerini hangi yönde etkilediği değerlendirilmiştir. Çalışmada, tanımlanmış ve geliştirilmiş rezervuara sahip olması nedeniyle, Türkiye'de bulunan iki farklı saha değerlendirilmiştir. Sonuç olarak, %95 olasılık için her iki tekniğin de benzer sonuçlar ürettiği bulunmuştur. Hesaplanan değerler arasındaki fark, yüzde olasılık değerleri azaldıkça artmaktadır.

Anahtar kelimeler: Dril-Stem Test (DST), Petrol Formasyon Hacim Katsayısı (FVF), Basınç Hacim Sıcaklık Analizi (PVT), Yerinde Petrol Miktarı (OOIP)

To My Family

ACKNOWLEDGMENTS

I express sincere appreciation to Prof. Dr. Mustafa Kök and Assoc. Prof. Dr. Serhat Akın for their guidance and suggestions throughout the research.
I would like to send my special thanks to M.Serkan Küçükekşi, I.Gökay Budak, Aydın Karaman and G.Fatih Serdar for their indispensable support and friendship.

I gratefully appreciate my best, Ahmet Bilge Uygur, Altar Eröz, and Tanıl Tarhan for their encouragement and invaluable friendship in every step of my study.

And finally, I dedicate this study to my mother and my father for their endless patience, understanding and support.

TABLE OF CONTENTS

LIST OF TABLES

TABLE

LIST OF FIGURES

FIGURE

LIST OF SYMBOLS

A Area

h Pay thickness

S_w Water saturation

B_o Formation volume factor

N/G Net to gross ratio

pu Planimeter unit

R_t True resistivity of uninvaded formation

R_{xo} Flashed zone resistivity

R_o Resistivity of porous rock saturated 100 % in conductive fluid

F Formation resistivity factor

DT Transit time of saturating fluid

M Moments of Equations

Greek Letters

ø Porosity

δ Statistical value

Abbreviations

PVT Pressure Volume Temperature

DST Drill Stem Test

ROIP Recoverable oil in place

CDF Cumulative distribution function

FVF Formation volume factor

ROI Return on investment

QRA Quantitative risk analysis

ANN Artificial neural network

GDI Geology driven integration tool

PPT Pantai Pakam Timur

GUPCO Gulf of Suez Petroleum Company

TPAO Turkish National Petroleum Company

DOE Department of Energy

LHS Latin Hypercube Sampling

LHC Latin Hypercube

CHAPTER 1

INTRODUCTION

Probabilistic estimating of hydrocarbon volumes has its most important application when associated with major petroleum development projects. Simulations may be carried out by two basic alternative methods that is analytical manipulation of data distributions or a Monte Carlo approach. While both methods have their inherent advantages, it is the latter method that lends itself more easily to describing uncertainties associated with hydrocarbon volumes which have to be estimated. In this respect one should differentiate between "recoverable hydrocarbons" (oil or gas), a quantity which represents the maximum possible recovery essentially governed only by physical reservoir processes and "reserves" which is the maximum quantity (usually less than recoverable hydrocarbons) that can be recovered with a certain development plan and production policy.

Reserves have three categories; proved, probable and possible [7].

Proved reserves are estimated quantities of hydrocarbons and other substances that are recoverable in future years from known reservoirs which geological and engineering data demonstrate with reasonable certainty. "Reasonable certainty" means that the average risk or confidence factor for recovering the amount estimated as proved is at least 90%.

Probable reserves are estimated quantities of hydrocarbons and other substances, in addition to proved, that geologic and engineering data demonstrate with reasonable probability to be recoverable in future years from known reservoirs. For these quantities to be reserves, this must be accomplished under existing economic and operating conditions. Reasonable probability means the average risk or confidence factor recovering the amount estimated as probable will be at least 50%.

Possible reserves are the estimated quantities of hydrocarbons and other substances in addition to proved and probable volumes that geologic and engineering data indicate the reasonably possible to be recovered in future years. Reasonable possibility means that the average risk or confidence factor for recovering the amount estimated as proved, probable and possible will exceed 5%.

Monte Carlo simulation is a statistics based analysis tool that yields probability-vs.-value relationship for parameters, including oil and gas reserves, and investments such as a net present value (NPV) and return on investment (ROI). These probability relationships help the user answer a question like "What is the probability that the NPV of this prospect will exceed the target of $2000000?". Nowadays Monte Carlo simulation is getting more applied in the major investment to better evaluate the appraisal of the projects, among which the economic evaluation of the petroleum industry applications forms the majority.

Probabilistic reserves estimating using a generalized Monte Carlo approach have many advantages over simpler deterministic or other probabilistic methods. The study, in which a risk analysis program used, deals more thoroughly with geologic structural dependency and at the same time allows for a high degree of accuracy. Data preparation is kept to a minimum, allowing seismic and other basic data to be used directly in calculations without the need of preparing time consuming area-depth graphs used in more conventional methods. A further advantage is the elimination of certain arbitrary decisions related to extreme structural scenarios based on geological mapping of a very limited number of possible situations. Sensitivities related to uncertainties and errors are handled in an easy manner.

In this study, estimation of the reserves of two Turkish oil fields will be estimated by using two different methods, Method of Moments and Monte Carlo Simulation. Field data will be evaluated in two different programs and results will be compared with each other.

CHAPTER 2

LITERATURE SURVEY

2.1. What is Risk Analysis and Monte Carlo Simulation?

The increasing importance of world's energy sources requires more precise studies of hydrocarbon reservoirs. The evaluation of reserves and production strategies are generally obtained by using various deterministic numerical modeling (simulation) techniques. Single point or deterministic modeling involves using a single 'best guess' estimate of each variable within a model to determine the model's outcome(s). Sensitivities are then performed on the model to determine how much the outcome might vary. This is achieved by selecting various combinations for each input variable. These various combinations are commonly known as 'what if' scenarios.

2.1.1. Quantitative Risk Analysis

Consider a simple model to determine a cost of a conjunction project, shown in Table 2.1. The model has broken down the projects cost into five separate items. Three points can be used, minimum, best guess and maximum, as values to use in a 'what if' analysis. Since there are five cost items and three values per item, there are 3^5=243 possible 'what if' combinations we could produce. Clearly, this is too large a set of scenarios to have any practical use. This process suffers from two other important drawbacks: only three values are being used for each variable, where they could, in fact, take any number of values; and no recognition is being given to the fact that the best guess value is much more likely to occur than the minimum and maximum values.

Table 2.1 Cost of a conjunction project example

	Minimum	Likely	Maximum
Excavation	30000	34200	39800
Foundations	23000	26200	33100
Structure	170000	176000	188000
Roofing	58200	63500	69700
Services	39300	47000	53800

Quantitative risk analysis (QRA) is any form of analysis that studies and hence attempts to quantify risks associated with an investment. So “risk” must be defined. Risk contains two essential components; uncertainty and loss. If the outcome of an action is uncertain or uncontrollable and may cause some loss (e.g., of money, human life), the action is risky. The degree of risk is based on both the probability of failure and the outcome for each failure. For instance, buying a lottery ticket is a no-risk action because the loss is insignificant, even though the probability of winning is very low (usually less than one in 10 million). On the other hand, petroleum exploration is a high risk business because the loss is large for one failure in drilling, even though the success rate may be more than 10%. This distinction is important. If you judge the situation to be risky, risk becomes one criterion for decision-making–and risk analysis becomes viable.

By risk, potential loss, and, more generally, loss or gain (i.e. change in assets associated with some chance occurrences) is meant. To use the term analysis, the risk must be quantifiable. Risks associated with building a gas-fired electric-power generating plant include the forecasts of gas price (on the cost side) and electric price (on the revenue side) as well as capital and operating costs, downtime and demand. The risks in drilling a well include the direct costs of the rig and of other goods and services, the possibilities of unscheduled events and the assessment of their consequences, the possibility of failure (i.e., a dry hole, a missed target, or an unsuccessful completion), the range of possibilities of success, and the chance of serious mishap. Risks associated with estimating reserves for an exploration prospect include estimation of the geological chance factors, economics, and forecasting risks.

2.1.1.1. Geological and Environmental Risks

The main factors and mechanisms that control petroleum accumulations are existence of a trap, source rock, thermal maturation, migration and timing, reservoir (storage capacity), seal, and productivity. To each of these events, are probabilities of success and failure assigned, based upon vague or registered experiences. As there is a lack of significant data based on which inferences of future risks may be made, the vague experience (or professional experience) is strongly used in the determination of the probabilities of the occurrence of the events.

Environmental risks concern the effects of human health, as well as ecosystem impacts, and the focus is on liability and insurance.

2.1.1.2. Economic Risks

These risks are established from the analysis of the parameters, which determine the size distribution (area and volume) of the possible accumulations of oil (structure area, thickness, porosity, saturation, and formation volume factor).

2.1.1.3. Production Forecasting Risks

Once the recoverable reserves are established, we need to estimate how fast the production, or the exploitation, or the depletion of the reserves of oil and gas will take place. Some important factors for these items are; number of wells, percentage of dry holes or success ratio, drainage area or recovery per well, productivity index per well, operating constraints on production rates, initial decline rates, abandonment rates or other abandonment conditions, and product prices. Suppose you have drilled 40 wells in a field-development program, 10 of which were deemed dry holes. What is the chance that the next well will be dry? Perhaps 10/40 is a good answer. It depends on whether there has been a trend to have fewer or more dry holes over time. In other words, is the success of one well in some was dependant on the success of others?

In a geological case, estimating the factors and obtaining the products is a form of risk analysis or in a production forecasting case, providing an estimate for the probability of a dry hole is a form of risk analysis so, the objective of a QRA is to calculate the combined impact of the model's various uncertainties in order to determine a probability distribution of the possible model outcomes.

One misconception about risk analysis is that risk analysis will eliminate risk in decision making. Indeed, risk and uncertainty cannot be eliminated from an event through any analysis method. Risk analysis tools do not reduce or eliminate risk; instead, they evaluate, quantify, and help you to understand risk so that you can design a decision strategy to minimize your exposure to risk [1].

Another misconception is that risk analysis methods can replace professional judgment. Risk analysis methods are intended to supplement, rather than replace, the necessary judgments. Personal experience and vision remain very important in decision making.

2.1.2. Risk Analysis Methods

In general, there are three different approaches that have been used in the risk-based decision process: (1) decision tree analysis, (2) stochastic simulation, and (3) artificial intelligence (AI) analysis methods. The applications of these three methods are based on the complexity of the problem.

Decision tree analysis is used for sequence decision making processes [1]. A diagram that looks like a tree branch has to be constructed to show all the subsequent possible events and decision options that are outcomes from previous decisions. This analysis method is used only for simple cases in which the anticipated events and the probability for each event are already known. Computations involved in this analysis are relatively simple and can be handled with calculators.

In many cases, the anticipated outcomes depend on several input variables whose values may not be known exactly. This kind of problem is usually analyzed by a stochastic simulation method, such as a Monte Carlo simulation [1,2,3]. The inputs are probability distributions, and the output of such stochastic methods is also given in terms of distributions. In contrast, the output of decision-tree analysis gives single values.

As the complexity of a system increases, the conventional quantitative techniques of system analysis become more and more unsuitable. For instance, predicting crude oil prices or the change in the price of a stock requires the consideration of too many uncertain factors. These influential factors are very hard to model with formal mathematical tools. To tackle these problems that are hard to deal with by formal logical means, one must employ unconventional methods, such as artificial neural networks and fuzzy expert systems.

Artificial intelligence technologies have the capability of reasoning from fuzzy, noisy, and incomplete information. Recently, these unconventional technologies have been applied in areas such as geologic play appraisal, drilling problem diagnosis, production forecasting, reservoir characterization, and Wall Street stock prediction. The implementations of AI technology and other tools for prediction and forecast can be confusing for nonprofessional users. Figure 2.1 provides a flow diagram to illustrate the applications of various prediction tools.

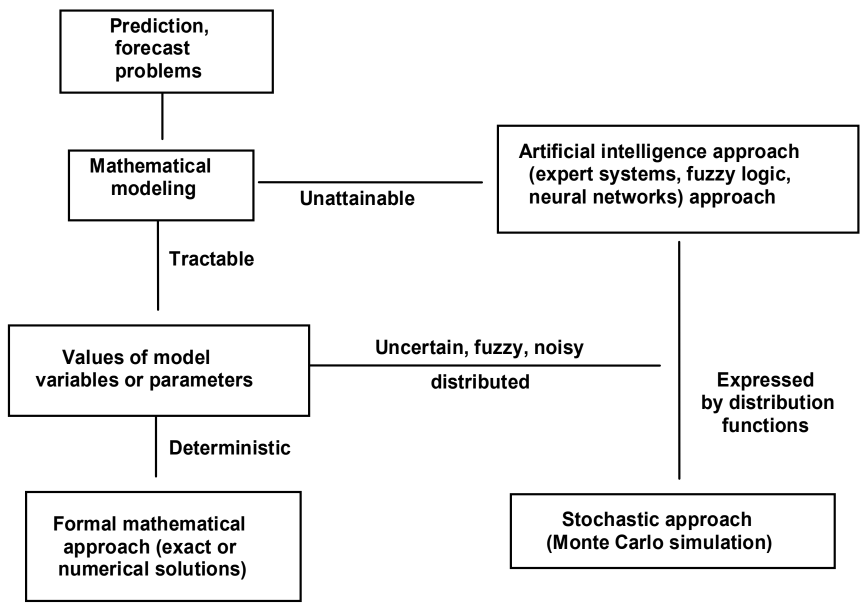

Figure 2.1- How Prediction Tools are Implemented

2.1.3. Monte Carlo Simulation

Monte Carlo simulation technique involves the random sampling of each probability distribution within the model to produce hundreds or even thousands of scenarios (Also called iterations or trials) [5]. Each probability distribution is sampled in a manner that reproduces the distribution's shape. The distribution of the values calculated for the model outcome therefore reflects the probability of the values that could occur.

A Monte Carlo Simulation begins with a model (i.e., one or more questions, together with assumptions and logic relating the parameters in the equations). For purposes of illustration, one form of a volumetric model for oil in place is selected.

$$OOIP = \frac{7758 \times A \times h \times \phi \times (1 - S_w)}{B_o} \qquad (2.1.3.1)$$

Where;

A: Area (acre)

h: Net Pay (ft)

ø: Porosity (%)

S_w: Water saturation (%)

B_o: Formation volume factor (rbbl/STB)

Think of *A, h, ø,* S_w and B_o as input parameters and *OOIP* as the output. Once we specify values for each input, we can calculate an output value. Each parameter is viewed as a random variable; it satisfies some probability vs. cumulative-value relationship. Thus, we may assume that the area, *A*, can be described by a lognormal distribution with a mean of 2000 acres and a standard deviation of 800 acres, having a practical range of approximately 600 to 5000 acres [6].

A trial consists of randomly selecting one value for each input and calculating the output. This combination of values would represent a particular realization of the prospect. A simulation is a succession of hundreds or thousands of repeated trials during which the output values are stored in a file in the computer memory. Afterward, the output values are diagnosed and usually grouped into a histogram or cumulative distribution function.

2.1.4. Probabilistic Approach to Reserve Estimation

As mentioned above, the stock tank oil in place (OOIP) is given by

$$OOIP = \frac{7758 \times A \times h \times \phi \times (1 - S_w)}{B_o} \qquad (2.1.3.1)$$

And recoverable oil in place (ROIP) is given by

$$ROIP = \frac{7758 \times A \times h \times \phi \times (1 - S_w)}{B_o} \times \frac{N}{G} \times RF \qquad (2.1.4.1)$$

Where $A \times h$ is the reservoir rock volume, S_w is water saturation, ø is porosity and B_o is formation volume factor for oil. N/G is net to gross thickness ratio as obtained from the logs, RF is the recovery factor. It is well known that initial estimates of all these variables have uncertainty. The data is usually obtained during drilling of the initial oil well. Sources are

- Geophysical (seismic surveys) for possible formation depths and areal extent of the reservoir trap
- Well logs for formation tops and bottoms
- Formation porosity, water saturation and possible permeable strata
- Core analysis for porosity and saturation data
- DST tests for possible oil production rates and oil samples for PVT analysis to obtain B_o and others

Each of the parameters entering the calculations has to be described by a probability distribution, representative of the original data (frequency distribution). Although such data preparation may be very time consuming, it is an important step in obtaining realistic results. One may first consider factors, which determine the type of distribution, which should be most appropriately used in describing a particular variable. The over riding factor would be data availability, that is in many situations only the most likely and range (extreme values) of a parameter may be known; in other cases a very detailed frequency distribution may exist as part of the data set. A second consideration would be simplicity and ease of handling of a particular distribution, especially if one were to manipulate distributions analytically. When a Monte Carlo approach is taken, original frequency distributions may be employed directly. Finally, when experience dictates the likelihood of a particular distribution in the presence of a sparse data set, sensitivity calculations for a number of possible distributions may be beneficial.

The triangular distribution is probably the most universal, particularly when dealing with a sparse data set for a particular parameter [2]. The unique feature of this distribution is that the shape is completely defined by three percentiles (or values), assuming that higher or lower values than the most likely one should have equal chance.

A second common distribution, found in describing geological uncertainty, is the log normal distribution [2]. This distribution stresses the likelihood of the mean. Manipulation of distributions, for example addition can be either probabilistic or arithmetic.

What is a random variable? A random variable is the link or rule that allows us to assign numbers to events by assigning a number –any real number- to each outcome of the sample space. We call the rule X, each outcome is called w, and the result is applying the rule is X(w). Sometimes X(w) is called a stochastic variable.

The idea this conveys is one of uncertainty. The random variable incorporates the idea that,

- Certain values will occur more frequently than others,
- The values may be ordered from smallest to largest,

- Although it may take any value in given range, each value is associated with its frequency of occurrence through a distribution function.

Given a random variable X, the Cumulative Distribution Function F(x) is defined as

$$\text{CDF } of \ F(x)=\text{Prob}\ (X \leq x) \tag{2.1.4.2}$$

In other words, F(x) is the probability of finding a random variable X that is less than or equal to x. The form of CDF may range from cases where there are infinite set of X`s, to where there is only one X (i.e. random variable becomes deterministic). By knowing the CDF (or probability distribution function) of a property in the reservoir we can produce models of how property varies within the reservoir. Reserves distributions can be modeled using CDF`s of several reservoir properties.

Monte Carlo method is a powerful tool for using random variables in computer programs. If we know the CDF`s of the variables, the method enables us to examine the effects of randomness upon the predicted outcomes of numerical models. Monte Carlo method requires that we have a model defined (such as equation 2.1.3.1 or 2.1.4.1) that relates the input variables (such as A×h, S_w, ø and B_o) to the feature of interest (such as OOIP) of the output quantity (e.g., OOIP) and the particular its variability are used to make decisions about economic viability)

Monte Carlo methods can be numerically demanding if many input variables are random and they all have variability, large number of runs and iterations of the model may be needed. In reserve calculations, the variables in Equation 2.1.4.1 are either measured or calculated, sometimes if there is no well drilled you may have to use the experience from a similar field in the same basin. If well data is available it is good, however porosity, saturation, N/G are only known for one location in the reserve namely the well bore.

2.1.5. Latin Hypercube Sampling (LHS)

LHS is a stratified sampling technique where the random variable distributions are divided into equal probability intervals [4]. A probability is randomly selected from within each interval for each basic event. During sampling, a sample is drawn from each interval. In LHS, the samples more accurately reflect the distribution of values in the input probability distribution. Generally, LHC will require fewer samples than simple Monte Carlo Simulation for similar accuracy. However, due to the stratification method, it may take longer to generate a value for a Monte Carlo Simulation. The LHC sampling method reduces the number of samples and variance. In LHC (as shown in Figure 2.2), the range of each variable is divided into non-overlapping intervals (m) on the basis of equal width or equal probability. These intervals are sampled according to probability density functions associated with the variables. Rather than sampling all possible combinations, the method selects only m of these combinations. Each stratum of each variable is only sampled once without replacement. Thus, the full range of each input variable is sampled. This can significantly improve the accuracy and convergence rate.

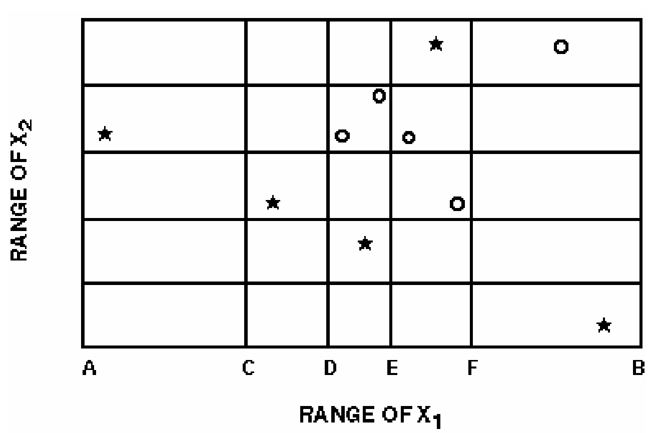

Figure 2.2 -LHC Sampling Method

Suppose one desires to select five input vectors from two variables X_1 and X_2. In Figure 2.3, the ranges of both variables are divided into five sub-regions. The asterisk (*) denotes a possible set of pairs (X_1; X_{2i}), ($i=1, 2,. ..., 5,$) selected by LHC. It is clear that LHC has forced each of the five intervals to be represented once, and the entire range of both $X1$ and $X2$ has been covered. In contrast, random sampling may result in the selection of pairs as indicated by the open circle (^{o}) in Figure 2.2. The ranges of both X_1 and X_2 are not fully covered [4,7].

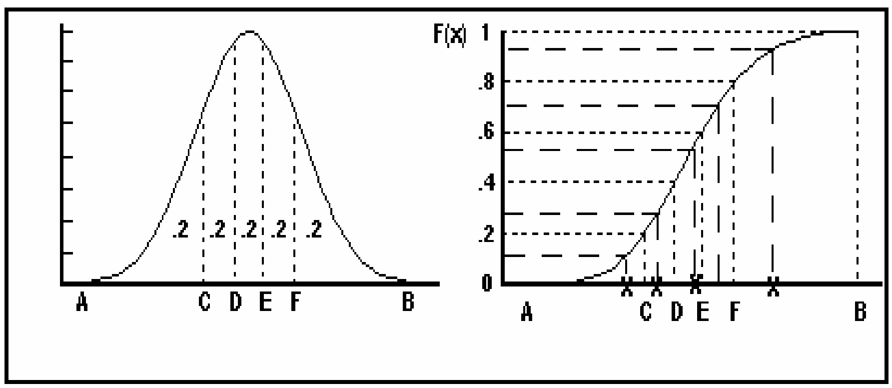

Figure 2.3- Sampling Results by LHC and Random Sampling Methods

2.1.6. Some Statistical concepts

In determination of probability distribution functions, it is better to overview some statistical concepts such as the average, variance, standard deviation, skewness, and kurtosis.

Average (mean) is the measure of central tendency for a normal distribution. The sample average may be computed by summing all of the measurements and dividing by the number of measurements. It is expressed by the following equation;

$$x = \left(\frac{1}{n}\right)\sum (x_i) \tag{2.1.6.1}$$

Variance is a measure of dispersion for a normal distribution. The reference used to measure the sample data is the sample average. A deviation is the difference between the sample average and observation, x_i. It is expressed by the following equation;

$$\delta^2 = \frac{1}{(n-1)}\sum (x_i - x)^2 \tag{2.1.6.2}$$

where n is the number of measurements in the sample, x_i equals the value of particular measurement from the sample, x is the sample average and the sigma (δ) is the sample standard deviation.

Standard deviation is the square root of the variance

$$\delta = \sqrt{\frac{1}{(n-1)}\sum (x_i - x)^2} \tag{2.1.6.3}$$

Skewness tests if the shape of a sample distribution is similar to that of a normal distribution. A risk investigator prefers positive skewness or a value between -0.5 and +0.5.

Kurtosis also tests if the shape of a sample distribution is similar to that of a normal distribution. A risk investigator prefers a distribution with low kurtosis.

2.2. Why to Use Monte Carlo Simulation?

There are several advantages of Monte Carlo Simulation stated by Vose [5]. Some of them are;

- The distributions of the model's variables do not have to be approximated in any way.
- Correlations and other inter-dependencies can be modeled.
- The level of mathematics required to perform a Monte Carlo simulation is basic.
- The computer does all of the work required in determining the outcome distribution.
- Software is commercially available to automate the tasks involved in the simulation.
- Greater levels of precision can be achieved by simply increasing the number of iterations that are calculated.
- Complex mathematics can be included (e.g. power functions, logs, if statements, etc.) with no extra difficulty.
- Monte Carlo simulation is widely recognized as a valid technique so its results are more likely to be accepted.
- The behavior of the model can be investigated with great ease.
- Changes to the model can be made very quickly and the results compared with previous models.

Monte Carlo simulation therefore provides results that are also far more realistic than those that are produced by 'what if' scenarios.

The importance of uncertainty and risk have been well recognized in the petroleum engineering literature, especially in the areas of exploration and reserve estimation [1,8]. Recently, petroleum engineers have also been focusing on methods for assessing the uncertainty in forecasts of primary and enhanced oil recovery processes [9,10]. In these (and related) studies, Monte-Carlo simulation is typically the method of choice for relating model input-output uncertainty. The Monte-Carlo simulation methodology allows a full mapping of the uncertainty in model inputs, expressed as probability distributions, into the corresponding uncertainty in model output which is also expressed in terms of a probability distribution [11].

In a research made by Galli *et al.*[12], three methods of evaluating oil projects were compared. Option pricing, decision trees and Monte Carlo simulations are three methods for evaluating oil projects that seem at first radically different. Option pricing comes from the world of finance. In its most common form, it incorporates Black and Scholes [12] model for spot prices and expresses the value of the project as a stochastic differential equation. Decision trees which come from operations research and games theory neglect the time variations in prices but concentrate on estimating the probabilities of possible values of the project, sometimes using Bayes theorem and prior and post probabilities. In their simplest form, Monte Carlo simulations merely require the user to specify the marginal distributions of all the parameters appearing in the equation for the Net Present Value (NPV) of the project. All three approaches seek to value the expected value of the project (or its maximum expected value) and possibly the histogram of project values but make different assumptions about the underlying distributions, the variation with time of input variables and the correlations between these variables. Another important difference is the way they handle the time value of money. Decision trees and Monte Carlo simulations use the traditional discount rate; option pricing make use of the financial concept of risk neutral probabilities. One of the difficulties in estimating the value of a project is that it is usually a non-linear function of the input variables; for example, because tax is treated differently in years when a profit is made to loss-making years.

Starting out from the NPV calculated on the base case, research shows how Monte Carlo simulations and decision trees build uncertainty and managerial flexibility into the evaluation methodology. Option pricing starts out by defining the options available to management and then models the uncertainty in key parameters. In fact the three approaches are different facets of a general framework; they can be obtained from it by focusing on certain aspects and simplifying or ignoring others.

As a conclusion of their work, they stated that a decision tree was a way of evaluating the maximum expected NPV whereas Monte Carlo simulations calculate the expected NPV for fixed scenarios. Unlike Monte Carlo simulations, decision trees of this type did not provide the histogram of possible NPVs. This seemed to be the price for incorporating decision choices. Both approaches used the traditional discount rate to take account of the time value of money, and both have problems dealing with correlated variables. Comparing Monte Carlo and option pricing methods, they stated that, in both cases the project life was fixed; the results gave the histogram of possible outcomes as well as the expected value. The essential difference lied in the way the time value of money was treated. In classical Monte Carlo simulations, the discount rate was used; in options the risk-free rate was used after a change to risk-neutral probabilities.

2.3. Where to Use Monte Carlo Simulation?

The most powerful risk assessment technique is the Monte Carlo simulation as it offers great capabilities of interactions, iterations, variations, and sensitivity analysis. However, this technique requires simple mathematical knowledge and statistical knowledge, through which, one can get reliable simulation.

As an example for a research, Nakayama [13] made a study about estimating the reservoir properties by using Monte Carlo Simulation. He studied a shallow gas zone in the Pantai Pakam Timur (PPT) field, located in Northern Sumatra, Indonesia. Only two wells were drilled in peripheral part of the field. In this situation the method of Geostatistics is hardly applied because of less control points, but there is a new suitable method to estimate reservoir properties under the condition of such few control points (GDI: Geology Driven Integration Tool).

To compensate few controls, GDI creates pseudo-wells by Monte Carlo Simulation method with regional geological constraints in its regulation, and generates theoretical seismic traces from them. Then the suitable seismic attributes are selected after checking the proportionality with the given reservoir property. Finally the artificial neural network (ANN) is applied to detect the weighting factors, which relate the selected seismic attributes to the given physical reservoir properties. This method is applied to the 2-D seismic records in the PPT field to extract successfully the distribution of porosity and thickness of the gas sandstone reservoir. The most prospected area is figured out in the southern part of the field, where the net thickness of gas zone is estimated to increase 27 meters with fairly higher porosity of 28%, which can be fairly confirmed by the well proposed and drilled by this study. Once getting the distribution, it is easier to calculate the total rock volume of the target reservoir under non-homogenized situation, and hence to progress on estimating more precise volume of reserves in place. Thus this method has an advantage in estimating reservoir characters from a few well data in the early development stage, or even in the late exploration stage. It is certainly important for asset managing that new idea should save the cost even in the stage of exploration.

In Nakayama's study, the reservoir extension of the shallow gas zone in Pantai Pakam Timur (PPT) gas field was tried to re-evaluate using a new method of reservoir characterization by Monte Carlo Simulation before some development stage started. The new well was drilled later at the location suggested from this study. Nakayama's study shows some increase of available volume which could be occupied by gas. The estimated reserves for the field may increase to be 92 BCF or 110 BCF at maximum. The result from this study implicates at least that a large domal structure with some local culminations may exist in the southern part of the PPT gas field.

As another example, Macary, Hassan and Ragaee [14] made a research about reservoir evaluations using Monte Carlo Simulation on Ramadan field.

Ramadan oil field located in the Central area of Gulf of Suez and operated by Gulf of Suez Petroleum Company (GUPCO) was chosen to conduct the study. This field provided a considerable set of data over about 25 years of exploitation and different phases of development. Ramadan oil field was subjected to sophisticated detailed petrophysical analyses and simulation studies to better address the reservoir description, overcome the reservoir management difficulties, and plan development projects. These studies have yielded a huge set of petrophysical data such as porosity, net pay thickness, and water saturation for each simulation layer.

Hersvik *et al.*[15] made a research about developing a field by using Monte Carlo Simulation. The Norwegian North Sea Brage was producing approximately 8000Sm^3/d and was on steep decline from its plateau rate of 19400Sm^3/d. In March 1999 it was decided to stop the drilling for approximately one year. During this year new reservoir models were built and history matched. Although this work proved to be both complicated and tedious it was fairly successful. However there was still a high degree of uncertainty in the understanding of the flow pattern and the pressure behavior of the field. It was therefore decided to perform a comprehensive uncertainty analysis to get better estimates of the expected production and risk related to a resumed drilling. The analysis was performed both on a well to well basis and combined into a drilling campaign. A reservoir simulator was utilized to estimate the unconstrained well potential for each well. Then total field water handling constraints was imposed using a tool that optimizes the production given the individual well profiles and the platform constraints. A basis was obtained for determining the base case Present Value, PV, for each well's contribution to the field production. For each well target, the most important uncertainties with corresponding probability distributions were identified, and their effect on the PV determined by simulations. In cases where the simulation model was judged not to represent the reservoir behavior correctly, analytical methods were used. Finally, these results were used together with the drilling cost into a Monte Carlo simulation loop to determine probability distributions for the NPV of each well and for the total drilling program. Hersvik [15] stated that the procedure has proven to be very flexible. It was easy to incorporate new uncertainties to a well and to exclude or include wells in the drilling campaign. Furthermore, it provided a very useful tool for evaluating the direct economic influence from reservoir uncertainties. The resulting NPV probability distributions provided an easy way of ranking well targets based on expected NPV and risk. It was shown that even though most of the individual well targets have a high risk of a negative NPV, the economy of the total drilling program was robust and has a significant upside economical potential. The procedure was based solely on commercially available software.

CHAPTER 5

STATEMENT OF THE PROBLEM

As there is uncertainty in the estimates of capital, reserves and net present value in petroleum industry, risk analysis is the key point for an oil company. It is easy to make decisions after quantifying the uncertainty with ranges of possible values and associated probabilities. Instead of deterministic models, probabilistic evaluations give wide range of outcomes for decision making. Monte Carlo Simulation is a tool that presents different scenarios and yields probability and value relationships in reserve evaluations.

In this study, estimation of the reserves of two Turkish oil fields will be performed by using Monte Carlo Simulation and Method of Moments. Field data will be evaluated in two different programs. One of them is a Petroleum Risk Assessment program named CashPot, which is designed to assist in determining the economic feasibility of oil and gas exploration and development projects and the other one is the Risk Analysis and Decision Making Program sponsored by U.S. Department of Energy (DOE). Results are going to be compared and discussed.

CHAPTER 6

METHODOLOGY

The minimum data requirement for probabilistic reserves calculations involves the following basic quantities; area and net pay or gross rock volume, net to gross rock thickness, porosity, hydrocarbon saturation, volumetric factor and recovery factor. In the usual manner, the hydrocarbon initially-in-place is the product of the first five quantities while recoverable hydrocarbons also include the recovery factor.

Reserves of Field A and Field B were reevaluated by using Monte Carlo Simulation in this work**.** F.A.S.T (Fekete's Advanced Software Technology) CashPot [16] and DOE [4] software were used for computing the values.

6.1. Cashpot

CashPot (short for Cash Potential) is a Petroleum Risk Assessment program designed to assist in determining the economic feasibility of oil and gas exploration and development projects.

Cashpot uses the method of moments as follows:

1. $m_1(x) = (x_{min} + 0.95x_{likely} + x_{max})/2.95$ (6.1.1)
2. $m_2(x) = m_1(x) + [(x_{max} - x_{min})/3.25]^2$ (6.1.2)

where: $m_1(x)$ = the first moment of parameter x
$m_2(x)$ = the second moment of parameter x
x_{min} = the minimum possible value of parameter x
x_{likely} = the most likely value of parameter x
x_{max} = the maximum possible value of parameter x

The moments of the product are calculated from the moments of the contributing parameters as follows:

$$M_1(X) = m_1(x_1) \times m_1(x_2) \times m_1(x_3) \times \ldots \quad (6.1.3)$$

$$M_2(X) = m_2(x_1) \times m_2(x_2) \times m_2(x_3) \times \ldots \quad (6.1.4)$$

where: $X = x_1 \times x_2 \times x_3 \ \ldots$
$M_1(X)$ = the first moment of product X
$M_2(X)$ = the second moment of product X

With these two composite moments, two more statistical values are calculated:

$$\delta^2 = \ln [M_2(X) \div M_{12} (X)] \quad (6.1.5)$$

$$\delta = \sqrt{\delta^2} \quad (6.1.6)$$

and from there, two more statistical values are calculated:

$$R_{50} = M_1(X)\, e\, (-\delta^2/2) \quad (6.1.7)$$

$$R_{84.1} = R_{50}\, e\, (\delta) \quad (6.1.8)$$

where

R_{50} = The 50 percentile of X

$R_{84.1}$ = The 84.1 percentile of X

The final output of CashPot -the Investment Plot- displays the risk profile without the burden of calculating and interpreting large amounts of statistical data. In order to run the program, necessary data should be obtained:

1. The gross rock volume is obtained by planimetering or integrating contour maps that describe the gross thickness between the crest of the accumulation and the hydrocarbon-water contact. In this manner the gross rock

volume may be obtained directly, or more frequently it is the result of area-thickness, area-depth or cumulative bulk volume vs. depth graph. In some cases where large areal variations exist in terms of net-to-gross thickness, porosity and saturation, these methods may be modified to yield net sand or net hydrocarbon vs. depth.

2. Net to gross ratio: Net to gross ratio is obtained by calculating the ratios of net pay thickness to the gross thickness from the log data.

3. Porosity: Porosity is the void space within the formation that contains the reservoir fluids and was obtained from log data. When porosity histogram was plotted, normal distribution was observed.

4. Water saturation: Water saturation is the amount of water within the pore spaces and expressed as a percentage of the pore space. The water saturation data was obtained from the logs for the calculations.

5. The Formation Volume Factor (Shrinkage): The volumetric factor is estimated from representative laboratory fluid sample analysis, and should correspond to the reservoir conditions, pressure and temperature, found at the net volume centroid of the accumulation, assuming linear fluid property variations with depth. The uncertainty in volumetric factors is usually, by comparison with other parameters, relatively small and in many cases the use of a constant value is satisfactory [17]. The shrinkage percentage is calculated from the formation factor value.

6. Recovery factor: Recovery factor is the percentage of OOIP that can be economically produced to surface. It is dependant on the nature of the reservoir, the stage of its development (primary vs. secondary recovery), and the number of wells. When OOIP is multiplied by the recovery factor, the result is called the reserves, the amount of oil that can be profitably produced. The recovery factor, often representing the most difficult parameter to be estimated may be obtained through engineering calculations, including reservoir simulation, or by considering case histories of similar reservoirs or fields. In this study, recovery factor is assumed to be between 15% and 35% due to the accepted range for sandstone and limestone reservoirs respectively [7].

6.2 DOE Software

DOE is a risk analysis and decision making software package. In order to evaluate Field A and Field B, Monte Carlo Simulation technique and Latin Hypercube Method is used. For the calculations, a model and the distribution types of the variables are required. Our model is the same as ROIP (eqn. 2.1.4.1) formula with six variables. The variables are;

1) Gross Rock Volume: It is hard to determine PDF as a very limited data set which is the result of mapping a very small number of possible scenarios. Standard approach is to employ triangular distribution.
2) N/G ratio: A triangular distribution is employed to net to gross ratio.
3) Porosity and Saturation: The histograms of porosity and saturation data are plotted. Average porosity and saturation by reservoir zone for each well is determined. Standard deviations are calculated. Correlation between porosity and saturation may be included.
4) Formation volume factor: The formation volume factor is estimated from laboratory analysis, so the value is taken as constant.
5) Recovery factor: A triangular distribution is employed to recovery factor as the accepted range for sandstone and limestone reservoirs is 15% and 35%.

The final results of the software are the statistical analysis (the minimum, the maximum, the mean, skewness, kurtosis, etc.), probability density distributions and cumulative distributions.

CHAPTER 7

RESULTS AND DISCUSSION

7.1 Field A

Field A has an anticlinal structure and the lithology is limestone. The entrapment is structural. Water oil contact is at -1470 m. and porosity and water saturation cuts are 7 % and 45 % respectively (according to company chosen values).

7.1.1 Bulk Volume Calculations

The bulk volume was calculated by planimetering the map shown in Figure B.16 in Appendix B. The results are shown in the Table 7.1 below.

Table 7.1 Planimeter results of Field A

Depth	AREA		
	Final PU	sq.cm	sq.km (scaled)
meters	A	B=A/10	D=A/1000
1210	110	11	0.1100
1220	382	38.2	0.3820
1230	577	57.7	0.5770

After calculating the area, gross rock volume is obtained from the Area vs. depth graph. The net thickness was taken as 11 m.

7.1.2 Input Values

The values of variables of Field A are shown in Table 7.2 and Table 7.3 below. The porosity and saturation cuts are taken 7 % and 45 % respectively due to the company policies.

Porosity and saturation values are taken from the log data shown in Table A.9, Table A.10, Table A.11, Table A.12 and Table A.13 in Appendix A. Pay thickness graph is shown in Figure B.1 in Appendix B.

Table 7.2 Input data of Cashpot for Field A

FIELD A – CASHPOT			
	Minimum	Most Likely	Maximum
Volume (acre-ft)	4100	4175	4250
N/G	0.5	0.6	0.7
Porosity (%)	7	13	22
Saturation (%)	5	23	45
Shrinkage (%)	2.9	2.9	2.9
RF (%)	15	25	35

Porosity and saturation distributions are taken as normal due to porosity and saturation histograms shown in Figure B.2 and Figure B.3 in Appendix B.

Table 7.3 Input data of DOE for Field A

FIELD A – DOE SOFTWARE						
	Distribution	Min.	Likely	Max.	Mean	Std. Dev
Volume (acre-ft)	Triangular	4100	4175	4250		
N/G	Triangular	0.5	0.6	0.7		
Porosity (%)	Normal				0.14	0.042
(1-S_w) (%)	Normal				0.75	0.103
FVF (bbl/STB)	Constant	1.03				
RF (%)	Triangular	15	25	35		

Due to the Porosity vs. Saturation graph shown in Figure B.4 in Appendix B, no correlation exists between porosity and water saturation.

7.2 Field B

Field B has an anticlinal structure and the lithology is dolomite and limestone. The entrapment is structural. Water oil contact is at -1230 m. and porosity and water saturation cuts are 7 % and 45 % respectively (according to company chosen values).

7.2.1 Bulk Volume Calculations

First, area of the reservoir was calculated using a planimeter from the map shown in Figure B.17 in Appendix B. The water oil contact was taken at 1470 m. obtained from the log data shown in Figure B.5 in Appendix B. After area calculation, bulk volume of the reservoir was calculated using different thicknesses to obtain minimum, likely, and maximum values of volume. From 15 m. minimum thickness to 40 m. maximum thickness, bulk volumes were calculated. Results are presented in Table A.1, Table A.2, Table A.3, Table A.4, Table A.5, Table A.6, Table A.7 and Table A.8 in Appendix A.

7.2.2 Input Values

The values of variables of Field B are shown in Table 7.4 and 7.5 below. The porosity and saturation cuts are taken 7 % and 45 % respectively due to the company policies.

Porosity and saturation values are taken from the log data shown in Table A.14, Table A.15, Table A.16, Table A.17, Table A.18 and Table A.19 in Appendix A. Pay thickness graph is shown in Figure B.5 in Appendix B.

Table 7.4 Input data of Cashpot for Field B

FIELD B – CASHPOT			
	Minimum	Most Likely	Maximum
Volume (acre-ft)	26672	33300	50710
N/G	0.2	0.5	0.7
Porosity (%)	7	18	23
Saturation (%)	11	29	45
Shrinkage (%)	2.9	2.9	2.9
RF (%)	15	25	35

Table 7.5 Input data of DOE for Field B

FIELD B – DOE SOFTWARE						
	Distribution	Min.	Likely	Max.	Mean	Std. Dev
Volume (acre-ft)	Triangular	26672	33300	50710		
N/G	Triangular	0.2	0.5	0.7		
Porosity (%)	Normal				0.16	0.026
$(1-S_w)$ (%)	Normal				0.71	0.076
FVF (bbl/STB)	Constant	1.03				
RF (%)	Triangular	15	25	35		

Porosity and saturation distributions are taken as normal due to porosity and saturation histograms shown in Figure B.6 and Figure B.7 in Appendix B.

Due to the Porosity vs. Saturation graph shown in Figure B.8 in Appendix B, no correlation exists between porosity and water saturation.

Sensitivity analysis for Cashpot can not be done as the OOIP vs. Repeats graph shows no stability. Increasing repeat numbers increases the resulting value (Figure B.9 in Appendix B).

The final plots of Cashpot for Field A and Field B are shown in Figure 7.1 and in Figure 7.2.

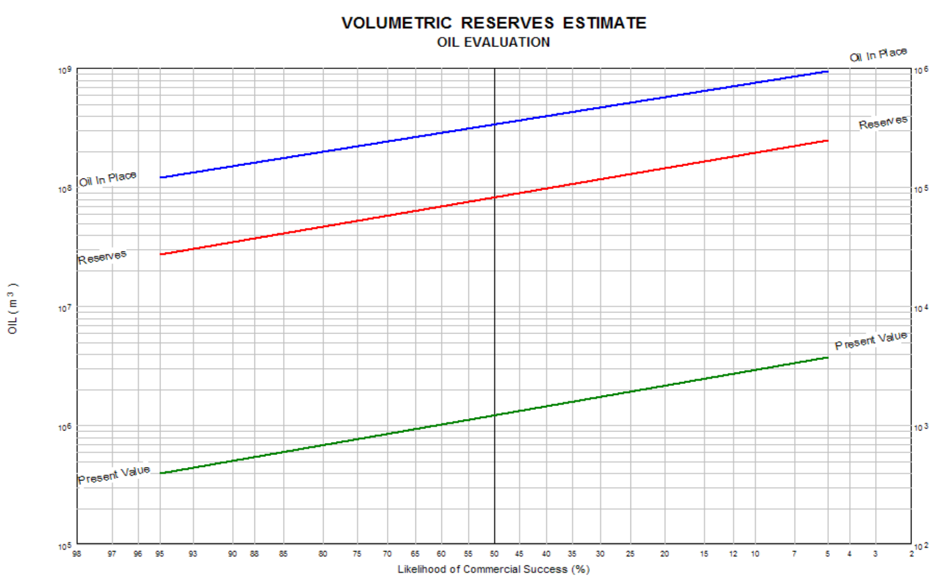

Figure 7.1- Reserves estimate plot for Field A

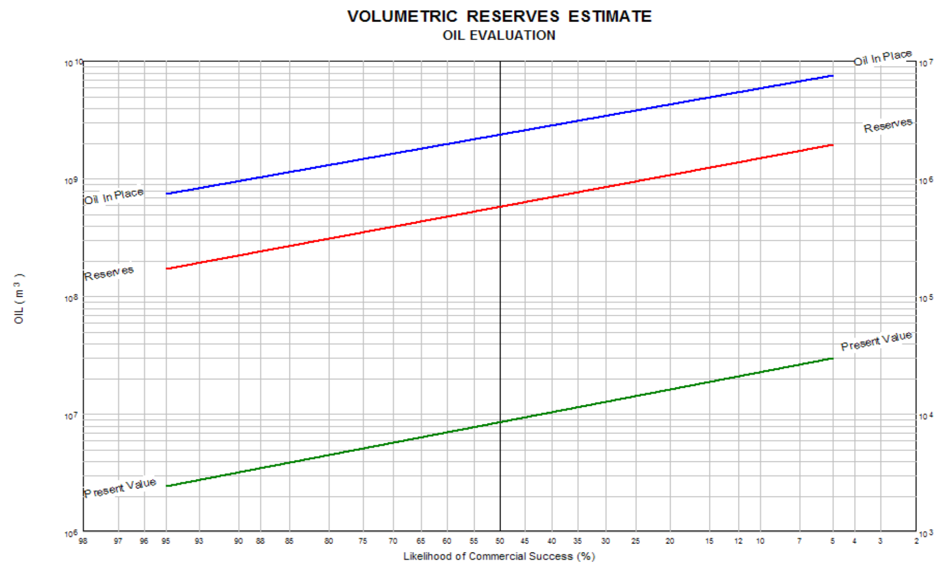

Figure 7.2- Reserves Estimate Plot for Field B

The results of DOE software is in Table 7.6 and Table 7.7.

Table 7.6- Output data of DOE for Field A

DOE results of Field A-Reserves and Statistical Values		
Sampling #	2500	3000
Minimum, STB	0.3276E+7	0.2070E+9
Maximum, STB	0.1408E+9	0.1346E+9
Mean, STB	0.4953E+8	0.4952E+8
Median, STB	0.4733E+8	0.4752E+8
Ave. Dev., STB	0.1497E+8	0.1479E+8
Variance, STB	0.3614E+15	0.3539E+15
Skewness (*)	0.6491	0.5828
Kurtosis (*)	0.7598	0.4598

(*) For statistical information, see Section 2.1.6

Table 7.7- Output data of DOE for Field B

DOE results of Field B-Reserves and Statistical Values		
Sampling #	2500	3000
Minimum, STB	0.8550E+8	0.6649E+8
Maximum, STB	0.9883E+9	0.1044E+10
Mean, STB	0.3682E+9	0.3680E+9
Median, STB	0.3492E+9	0.3493E+9
Ave. Dev., STB	0.1083E+9	0.1061E+9
Variance, STB	0.1862E+17	0.1842E+17
Skewness (*)	0.7504	0.8192
Kurtosis (*)	0.5929	1.001

(*) For statistical information, see Section 2.1.6

A sensitivity analysis was conducted. The error percentages for Field A and Field B are calculated as 0.4 % and 0.03 % respectively. Low percentages show that there is a negligible difference between the results of 2500 sampling and 3000 sampling. The error percentages for two fields when 2000 and 2500 sampling numbers are used are 1.74 % for Field A and 1.3 % for Field B. The results mean that increasing sampling numbers decreases the error percentage. Thus, an optimum number 3000 was taken as the sampling (or iteration) number. Also, in Cashpot, the porosity values are increased 10% for Field A and Field B and reserves were changed 3.3% and 4.45% respectively. A 10% increase in saturation affected the reserves to decrease 0.94% and 1.34%. But, A 1% increase in gross rock volume for Field A affected the reserves to increase 0.3% and a 10% increase in gross rock volume for Field B affected the reserves to increase 31.2%. These percentages show that the gross rock volume has the most powerful effect on reserve calculations. Figure B.10, Figure B.11, Figure B.12, Figure B.13, Figure B.14, Figure B.15 and Figure B.16 in Appendix B show the reserves estimate plots for sensitivity analysis of Field A and Field B.

The recoverable oil in place values are shown in Table 7.8.

Table 7.8- Comparison of the results of Software

	Field A-Reserves in STB		Field B-Reserves in STB	
Probability	DOE	CASHPOT	DOE	CASHPOT
5 %	0.8417E+8	2.5E+8	0.6183E+9	2.1E+9
50 %	0.4752E+8	0.826E+8	0.3492E+9	0.579E+9
95 %	0.2233E+8	0.28E+8	0.1799E+9	0.18E+9

As can be seen in ROIP vs. Probability graphs shown in Figure7.1 and Figure7.2, 95 % values of both programs are nearly the same. It is observed that when the probabilities decrease, difference between the results of the programs increase. The reason for such big differences is the probability due to the use of triangular distribution.

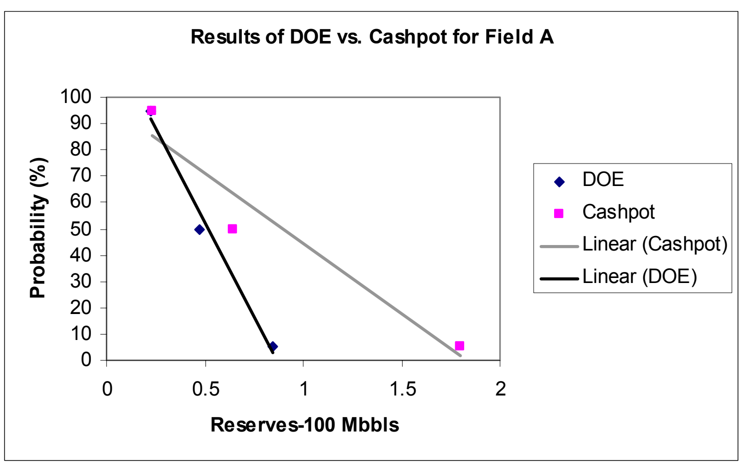

Figure 7.3- Results of DOE vs. Cashpot for Field A

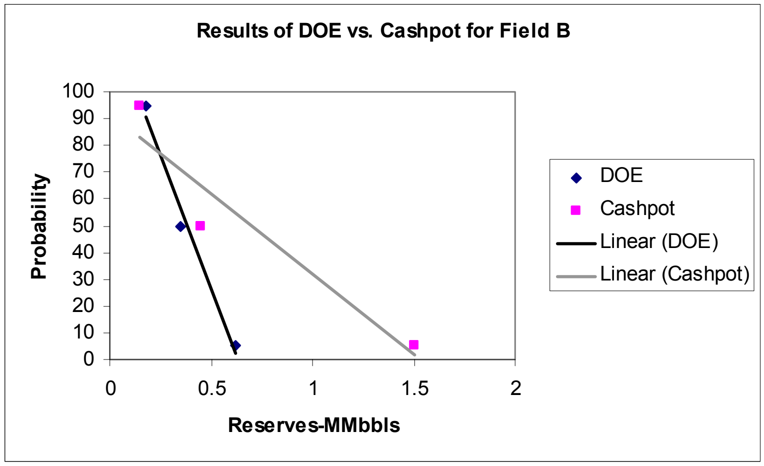

Figure 7.4 Results of DOE vs. Cashpot for Field B

The number of wells drilled must be increased to obtain better results for both of the simulations. For, DOE, if there is enough data about the area, different type of distributions may be used for more accurate results. And, for Cashpot, it will be easier to define the minimum, most likely and maximum values from enough number of data.

The water saturation and porosity cuts, defined by the company, are affecting the results, as number of data and volumetric calculations change when the saturation and porosity cuts are changed.

When using Cashpot Software as opposed to normal distributions used in DOE, resulting values show similarity only at higher probabilities and the difference between the results increase with decreasing probability. The skewness values in DOE show stability. The reason may be due to the differences in the techniques such that moment technique is less robust, compared to Monte Carlo Simulation.

CHAPTER 8

CONCLUSION

As mentioned above, reserve estimation in petroleum industry is important for reservoir evaluation and investment projects. In the current study, a systematic procedure for risk assessment and uncertainty analysis has been presented and two Turkish oil fields were re-evaluated by two different software using Monte Carlo Simulation. The conclusions derived from the study are;

- Probabilistic methods are useful for estimation of hydrocarbon reserves particularly when they are related to large projects contracted deliveries.

- Monte Carlo methods provide more proper handling of partial dependencies related to gross rock volumes of a structure.

- Monte Carlo Simulation was successfully applied in both of the software programs to the real field to determine the reserves in place. In the application, the reservoir was considered to be heterogeneous.

- In DOE software, when the number of samples increases, the error percentage decreases. And error percentage is negligible between 2500 samples and 3000 samples. An optimum number 3000 was taken as the sampling (or iteration) number.

- Triangular distribution is applied to gross rock volume, net to gross ratio and the recovery factor in calculations as there were not enough data for these variables. On the other hand, normal distribution is applied to porosity and water saturation calculations as there were log analysis for statistical calculations.

- For DOE, no correlation exists between porosity and saturation in ROIP formula for both of the fields.

- In Cashpot, the gross rock volume had the most powerful effect in the calculations. The other variables did not change the result widely.

- The Cashpot simulation provided a very useful tool for evaluating the direct economic influence from reservoir uncertainties. The resulting NPV plot provides an easy way of ranking well targets based on expected NPV and risk.

- It is observed that when the probabilities decrease, difference between the results of the programs increase. The reason for such big differences is the probability due to the use of triangular distribution.

- When using Cashpot Software as opposed to normal distributions used in DOE, resulting values show similarity only at higher probabilities and the difference between the results increase with decreasing probability.

- The number of wells drilled must be increased to obtain better results for both of the simulations.

-The water saturation and porosity cuts, defined by the company, are affecting the results, as number of data and volumetric calculations change when the saturation and porosity cuts are changed.

- DOE software is more useful if the risk analyzer has too many data for calculations. If not, the analyzer can make decisions by using Cashpot. Cashpot is a practical software for instantaneous scenarios.

REFERENCES

1. Newendorp, P.D., “Decision Analysis for Petroleum Exploration”, Pennwell Books, Tulsa, Oklahoma, 1975.
2. Law, A.M., and Kelton, W.D, “Simulation Modeling & Analysis”, McGraw-Hill Inc., New York, 1991.
3. Rubinstein, R.Y., “Simulation and the Monte Carlo Method”, John Wiley & Sons, New York, 1981.
4. Risk Analysis and Decision-Making Software Package (1997 Version).
5. Vose, D., “Quantitative Risk Analysis: A Guide to Monte Carlo Simulation Modeling”, Wiley & Sons, England, 1996.
6. Murtha, J. A., “Monte Carlo Simulation: Its Status and Future”, SPE 37932, Society of Petroleum Engineers’ Annual Technical Conference and Exhibition, Texas, USA, 1997.
7. Yükseler, U., “Reserve Estimation Using Stochastic Approach and Risk Analysis”, MSc Thesis, 2002.
8. Garb, F. A., “Assessing Risk in Estimating Hydrocarbon Reserves and in Evaluating Hydrocarbon Producing Properties”, JPT, 1988, Page765.
9. Brown, C. E., Smith, P. J., “The Evaluation of Uncertainty in Surfactant EOR Performance Prediction”, SPE 13237, SPE Annual Technical Conference and Exhibition, Houston, 1984.
10. Ovreberg, O., Damsleth E., Haldosen, H. H.,”Putting Error Bars on Reservoir Engineering Forecasts”, JPT, 1992, Page 732.
11. Mishra, S., “Alternatives to Monte Carlo Simulation for Probabilistic Reserves Estimation and Production Forecasting”, SPE 49313, SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, 1998.

12. Galli, A., Armstrong, M., Jehl, B., "Comparing Three Methods for Evaluating Oil Projects: Option Pricing, Decision Trees, and Monte Carlo Simulations", SPE 52949, Hydrocarbon Economics and Evaluation Symposium, Dallas, Texas, 1999.
13. Nakayama, K., "Estimation of Reservoir Properties by Monte Carlo Simulation", SPE 59408, Society of Petroleum Engineering Asia Pacific Conference, Japan, 2000.
14. Macary, S. M., Hassan, A., Ragaee, E., "Better Understanding of Reservoir Statistics is the Key for Reliable Monte Carlo Simulation", SPE 53264, Middle East Oil Show, Bahrain, 1999.
15. Hersvik, K. J., Aanonsen, S. I., Petersen, L. S., Fjellbirkeland, H., Robson A., Sperre, T., "Well Planning Under Uncertainty: Application of a Systematic Procedure for Risk Assessment and Uncertainty Analysis for New Well Targets on the Brage Field", SPE 65147, European Petroleum Conference, France, 2000.
16. F.e.k.e.t.e. CashPot Risk Evaluation Program, www.Fekete.com
17. Behrenbruch, P., Turner, G. J., Backhouse, A. R., "Probabilistic Hydrocarbon Reserves Estimation: A Novel Monte Carlo Approach", SPE, 13982

APPENDIX A

TABLES

This appendix will contain tables of bulk volume calculations and log data of the Fields.

Table A.1-Conversion of Results to Real Units

Depth, m	**Area**		
	Final pu	Sq. cm	Sq. km
1400	13	1.3	0.08
1410	34	3.4	0.21
1420	58	5.8	0.36
1430	123	12.3	0.77
1440	170	17	1.06
1450	239	23.9	1.49
1460	324	32.4	2.03
1470	426	42.6	2.66

Table A.2-Conversion Factors

FINAL READINGS on Area &Depth CHART		
10m x 0.2km^2	40	pu
1m x 1km^2	20	pu
1 km^2	247.10439	acre
1 m	3.28083	ft
1m x 1km^2	810.70750	acre-ft

Table A.3-Bulk Volume for 15 m Thickness

PU for 15 meter thickness		
Reading 1	Reading 2	Final
660	656	658
32.90	m- km^2	
26,672	acre-ft	

Table A.4-Bulk volume for 20 m. thickness

PU for 20 meter thickness		
Reading 1	Reading 2	Final
821	822	821.5
41.08	m-sq. Km	
33,300	Acre-ft	

Table A.5-Bulk volume for 25 m. thickness

PU for 25 meter thickness		
Reading 1	Reading 2	Final
950	948	949
47.45	m-sq. Km	
38,468	Acre-ft	

Table A.6-Bulk volume for 30 m. thickness

PU for 30 meter thickness		
Reading 1	Reading 2	Final
1062	1072	1067
53.35	m-sq. Km	
43,251	acre-ft	

Table A.7-Bulk volume for 35 m. thickness

PU for 35 meter thickness		
Reading 1	Reading 2	Final
1170	1174	1172
58.60	m-sq. Km	
47,507	acre-ft	

Table A.8-Bulk volume for 40 m. thickness

PU for 40 meter thickness		
Reading 1	Reading 2	Final
1252	1250	1251
62.55	m-sq. Km	
50,710	acre-ft	

Table A.9- Log Data of Well 1 of Field A

BSL	Depth	Matrix	Porosity D	Porosity N	Rt	Rxo	DT	Porosity sonic	F	Ro	Sw
M	m		%	%	ohm-m	ohm-m	µsec/ft	%		ohm-m	%
-1236	1958	dolomite	14.4	15	65	10	55	7.9	44.4	12.7	44.1
-1237	1959	dolomite	24.1	25	100	20	70	18.2	16.0	4.6	21.4
-1238	1960	dolomite	24.1	27	140	30	70	18.2	13.7	3.9	16.7
-1239	1961	dolomite	25.1	28	140	33	70	18.2	12.8	3.6	16.1
-1240 -1241	1962	dolomite	22.5	29	160	40	65	14.8	11.9	3.4	14.6
	1963	dolomite	22.5	23	200	40	65	14.8	18.9	5.4	16.4
-1242	1964	dolomite	19.8	18	200	55	60	11.3	30.9	8.8	21.0
-1243	1965	dolomite	15.5	16	220	36	55	7.9	39.1	11.1	22.5
-1244	1966	dolomite	17.1	18	130	45	59	10.7	30.9	8.8	26.0
-1245	1967	dolomite	17.6	20	65	25	60	11.3	25.0	7.1	33.1
-1246	1968	dolomite	11.2	14	100	6	57	9.3	51.0	14.5	38.1
-1247	1969	dolomite	12.8	12	45	6	56	8.6	69.4	19.8	66.3
-1248	1970	limestone	6.4	12	50	4.5	56	6.0	69.4	19.8	62.9

Table A.9- Log Data of Well 1 of Field A-Continued

BSL	Depth	Matrix	Porosity D	Porosity N	Rt	Rxo	DT	Porosity sonic	F	Ro	Sw
M	m		%	%	ohm-m	ohm-m	μsec/ft	%		ohm-m	%
-1249	1971	limestone	9.4	9	60	4	55	5.3	123.5	35.2	76.6
-1250	1972	limestone	4.7	10	50	100	55	5.3	100.0	28.5	75.5
-1251	1973	dolomite	12.3	12	50	100	55	7.9	69.4	19.8	62.9
-1252	1974	dolomite	12.3	12	50	100	55	7.9	69.4	19.8	62.9
-1253	1975	dolomite	12.3	12	60	100	55	7.9	69.4	19.8	57.4
-1254	1976	dolomite	12.3	12	70	140	55	7.9	69.4	19.8	53.2

Table A.10- Log Data of Well 2 of Field A

BSL M	Depth m	Matrix	Porosity D %	Porosity N %	Rt ohm-m	Rxo ohm-m	DT μsec/ft	Porosity sonic %	F	Ro ohm-m	Sw %
-1211	1940	dolomite	27.8	30	200	50	75	21.6	11.1	3.2	12.6
-1212	1941	dolomite	27.8	30	200	50	75	21.6	11.1	3.2	12.6
-1213	1942	dolomite	27.8	30	200	50	75	21.6	11.1	3.2	12.6
-1214	1943	dolomite	27.8	30	200	50	75	21.6	11.1	3.2	12.6
-1215	1944	dolomite	19.8	15	200	50	75	21.6	44.4	12.7	25.2
-1216	1945	dolomite	19.8	15	200	50	65	14.8	44.4	12.7	25.2
-1217	1946	dolomite	25.1	27	200	50	70	18.2	13.7	3.9	14.0
-1218	1947	dolomite	25.1	27	200	50	70	18.2	13.7	3.9	14.0
-1219	1948	dolomite	20.9	18	200	50	70	18.2	30.9	8.8	21.0
-1220	1949	dolomite	20.9	18	100	50	70	18.2	30.9	8.8	29.7
-1221	1950	dolomite	23.5	25	90	50	70	18.2	16.0	4.6	22.5
-1222	1951	dolomite	23.5	25	60	50	60	11.3	16.0	4.6	27.6
-1223	1952	limestone	9.4	11	60	190	60	8.8	82.6	23.6	62.7
-1224	1953	limestone	9.4	11	60	190	60	8.8	82.6	23.6	62.7

Table A.10- Log Data of Well 2 of Field A-Continued

BSL	Depth	Matrix	Porosity D	Porosity N	Rt	Rxo	DT	Porosity sonic	F	Ro	Sw
M	m		%	%	ohm-m	ohm-m	µsec/ft	%		ohm-m	%
-1225	1954	limestone	14.0	16	30	50	60	8.8	39.1	11.1	60.9
-1226	1955	dolomite	21.4	16	30	50	60	11.3	39.1	11.1	60.9
-1227	1956	dolomite	21.4	16	30	50	60	11.3	39.1	11.1	60.9
-1228	1957	dolomite	22.5	24	30	50	60	11.3	17.4	4.9	40.6
-1229	1958	dolomite	22.5	24	50	50	60	11.3	17.4	4.9	31.5
-1230	1959	dolomite	22.5	24	90	100	60	11.3	17.4	4.9	23.4
-1231	1960	dolomite	22.5	24	110	220	60	11.3	17.4	4.9	21.2

Table A.11- Log Data of Well 3 of Field A

BSL M	Depth m	Matrix	Porosity D %	Porosity N %	Rt ohm-m	Rxo ohm-m	DT µsec/ft	Porosity sonic %	F	Ro ohm-m	Sw %
-1204	1966	dolomite	27.8	28	150	50	72	19.6	12.8	3.6	15.6
-1205	1967	dolomite	27.8	28	150	50	72	19.6	12.8	3.6	15.6
-1206	1968	dolomite	27.8	28	150	50	72	19.6	12.8	3.6	15.6
-1207	1969	dolomite	27.8	28	150	50	72	19.6	12.8	3.6	15.6
-1208	1970	dolomite	27.8	28	150	50	72	19.6	12.8	3.6	15.6
-1209	1971	dolomite	27.8	28	150	50	72	19.6	12.8	3.6	15.6
-1210	1972	dolomite	27.8	28	150	50	72	19.6	12.8	3.6	15.6
-1211	1973	dolomite	27.8	28	150	50	65	14.8	12.8	3.6	15.6
-1212	1974	dolomite	17.1	21	80	50	65	14.8	22.7	6.5	28.4
-1213	1975	dolomite	19.8	15	30	50	65	14.8	44.4	12.7	65.0
-1214	1976	limestone	10.5	12	40	50	65	12.4	69.4	19.8	70.3
-1215	1977	limestone	9.4	9	40	50	65	12.4	123.5	35.2	93.8
-1216	1978	limestone	15.2	15	15	190	65	12.4	44.4	12.7	91.9
-1217	1979	limestone	15.2	15	15	190	68	14.5	44.4	12.7	91.9

Table A.11- Log Data of Well 3 of Field A-Continued

BSL	Depth	Matrix	Porosity D	Porosity N	Rt	Rxo	DT	Porosity sonic	F	Ro	Sw
M	m		%	%	ohm-m	ohm-m	μsec/ft	%		ohm-m	%
-1218	1980	limestone	15.2	15	15	50	68	14.5	44.4	12.7	91.9
-1219	1981	dolomite	20.9	17	15	50	68	16.8	34.6	9.9	81.1
-1220	1982	dolomite	20.9	17	15	50	68	16.8	34.6	9.9	81.1
-1221	1983	dolomite	20.9	17	15	50	68	16.8	34.6	9.9	81.1
-1222	1984	dolomite	20.9	17	15	50	68	16.8	34.6	9.9	81.1
-1223	1985	dolomite	20.9	17	15	100	68	16.8	34.6	9.9	81.1
-1224	1986	dolomite	20.9	17	15	220	68	16.8	34.6	9.9	81.1

Table A.12- Log Data of Well 8 of Field A

BSL	Depth	Matrix	Porosity D	Porosity N	Rt	Rxo	DT	Porosity sonic	F	Ro	Sw
M	m		%	%	ohm-m	ohm-m	µsec/ft	%		ohm-m	%
-1296	2049	dolomite	14.4	3	100	3000	52	5.8	1111.1	316.7	32.5
-1297	2050	dolomite	16.0	21	2000	3000	55	7.9	22.7	6.5	4.6
-1298	2051	dolomite	19.8	22	200	170	57	9.3	20.7	5.9	18.6
-1299	2052	dolomite	19.8	15	90	100	57	9.3	44.4	12.7	35.6
-1300	2053	limestone	6.4	6	70	130	52	3.2	277.8	79.2	78.0
-1301	2054	limestone	5.3	5	190	500	52	3.2	400.0	114.0	47.7
-1302	2055	limestone	3.5	6	300	800	52	3.2	277.8	79.2	31.5
-1303	2056	dolomite	12.8	8	300	300	52	5.8	156.3	44.5	38.5
-1304	2057	dolomite	14.4	8	120	100	52	5.8	156.3	44.5	66.7
-1305	2058	dolomite	14.4	8	130	100	52	5.8	156.3	44.5	66.7
-1306	2059	dolomite	14.4	8	140	90	52	5.8	156.3	44.5	70.3
-1307	2060	dolomite	11.8	7	120	70	52	5.8	204.1	58.2	91.2
-1308	2061	dolomite	10.7	2	150	80	52	5.8	2500.0	712.5	298.4

Table A.13- Log Data of Well 9 of Field A

BSL	Depth	Matrix	Porosity D	Porosity N	Rt	Rxo	DT	Porosity sonic	F	Ro	Sw
M	m		%	%	ohm-m	ohm-m	μsec/ft	%		ohm-m	%
-1221	1955	dolostone	23.5	25	140	200	53	6.5	16.0	4.6	15.1
-1222	1956	dolostone	23.5	25	40	100	70	18.2	16.0	4.6	21.4
-1223	1957	dolostone	23.5	25	44	120	70	18.2	16.0	4.6	19.5
-1224	1958	dolostone	23.5	25	40	100	70	18.2	16.0	4.6	21.4
-1225	1959	dolostone	23.5	25	28	90	70	18.2	16.0	4.6	22.5
-1226	1960	dolostone	19.8	18	20	70	70	18.2	30.9	8.8	35.4
-1227	1961	dolostone	19.8	18	39	80	63	13.4	30.9	8.8	33.2
-1228	1962	limestone	12.3	18	25	100	63	11.0	30.9	8.8	29.7
-1229	1963	limestone	12.3	19	39	80	63	11.0	27.7	7.9	31.4
-1230	1964	limestone	14.0	15	18	50	63	11.0	44.4	12.7	50.3
-1231	1965	dolostone	19.8	13	12	40	60	11.3	59.2	16.9	64.9
-1232	1966	dolostone	17.1	12	12	40	60	11.3	69.4	19.8	70.3
-1233	1967	dolostone	17.1	12	12	40	60	11.3	69.4	19.8	70.3
-1234	1968	dolostone	17.1	10	12	40	60	11.3	100.0	28.5	84.4

Table A.13- Log Data of Well 9 of Field A-Continued

BSL	Depth	Matrix	Porosity D	Porosity N	Rt	Rxo	DT	Porosity sonic	F	Ro	Sw
M	m		%	%	ohm-m	ohm-m	µsec/ft	%		ohm-m	%
-1235	1969	dolostone	14.4	9	12	40	60	11.3	123.5	35.2	93.8
-1236	1970	dolostone	16.0	17	6	70	60	11.3	34.6	9.9	37.5
-1237	1971	dolostone	16.0	17	6	70	60	11.3	34.6	9.9	37.5
-1238	1972	dolostone	16.0	17	6	50	60	11.3	34.6	9.9	44.4
-1239	1973	dolostone	16.0	17	6	50	60	11.3	34.6	9.9	44.4
-1240	1974	dolostone	16.0	17	6	50	60	11.3	34.6	9.9	44.4
-1241	1975	dolostone	16.0	17	6	50	60	11.3	34.6	9.9	44.4

Table A.14-Log data of Well 2 of Field B

BSL	Depth	Density	Porosity D	Porosity N	R_t	R_{xo}	DT	Porosity sonic	F	R_o	S_w
M	m	g/cc	%	%	ohm-m	ohm-m	μsec/ft	%		ohm-m	%
-1429	1916	2.4	18.1	17	200	35	67	13.8	34.6	2.6	11.4
-1430	1917	2.4	18.1	17	150	35	67	13.8	34.6	2.6	13.2
-1431	1918	2.4	18.1	17	140	35	67	13.8	34.6	2.6	13.6
-1432	1919	2.35	21.1	19	70	20	73	18.0	27.7	2.1	17.2
-1433	1920	2.35	21.1	19	50	20	73	18.0	27.7	2.1	20.4
-1434	1921	2.35	21.1	19	50	20	73	18.0	27.7	2.1	20.4
-1435	1922	2.35	21.1	19	70	20	73	18.0	27.7	2.1	17.2
-1436	1923	2.35	21.1	19	60	20	73	18.0	27.7	2.1	18.6
-1437	1924	2.35	21.1	19	60	20	73	18.0	27.7	2.1	18.6
-1438	1925	2.37	19.9	17	60	30	70	15.9	34.6	2.6	20.8
-1439	1926	2.37	19.9	17	60	30	70	15.9	34.6	2.6	20.8
-1440	1927	2.37	19.9	17	60	30	70	15.9	34.6	2.6	20.8
-1441	1928	2.37	19.9	17	60	30	70	15.9	34.6	2.6	20.8

Table A.14-Log data of Well 2 of Field B–Continued

BSL	Depth	Density	Porosity D	Porosity N	Rt	Rxo	DT	Porosity sonic	F	Ro	Sw
M	m	g/cc	%	%	ohm-m	ohm-m	µsec/ft	%		ohm-m	%
-1442	1929	2.37	19.9	17	60	30	70	15.9	34.6	2.6	20.8
-1443	1930	2.37	19.9	17	60	30	70	15.9	34.6	2.6	20.8
-1444	1931	2.37	19.9	15	80	50	70	15.9	44.4	3.3	20.4
-1445	1932	2.37	19.9	15	80	50	70	15.9	44.4	3.3	20.4
-1446	1933	2.37	19.9	15	80	50	67	13.8	44.4	3.3	20.4
-1447	1934	2.37	19.9	15	80	50	67	13.8	44.4	3.3	20.4
-1448	1935	2.37	19.9	15	60	50	67	13.8	44.4	3.3	23.6
-1449	1936	2.37	19.9	15	60	50	67	13.8	44.4	3.3	23.6
-1450	1937	2.37	19.9	15	60	50	67	13.8	44.4	3.3	23.6
-1451	1938	2.37	19.9	15	60	50	67	13.8	44.4	3.3	23.6
-1452	1939	2.37	19.9	15	60	50	67	13.8	44.4	3.3	23.6
-1453	1940	2.42	17.0	14	60	50	67	13.8	51.0	3.8	25.3
-1454	1941	2.42	17.0	14	60	50	67	13.8	51.0	3.8	25.3
-1455	1942	2.42	17.0	14	60	50	67	13.8	51.0	3.8	25.3

Table A.14 –Log data of Well 2 of Field B-Continued

BSL	Depth	Density	Porosity D	Porosity N	Rt	Rxo	DT	Porosity sonic	F	Ro	Sw
M	m	g/cc	%	%	ohm-m	ohm-m	µsec/ft	%		ohm-m	%
-1456	1943	2.42	17.0	10	60	50	67	13.8	100.0	7.5	35.4
-1457	1944	2.45	15.2	10	140	100	62	10.2	100.0	7.5	23.1
-1458	1945	2.45	15.2	10	140	100	62	10.2	100.0	7.5	23.1
-1459	1946	2.45	15.2	10	140	100	62	10.2	100.0	7.5	23.1
-1460	1947	2.45	15.2	10	70	30	62	10.2	100.0	7.5	32.7
-1461	1948	2.45	15.2	10	70	30	62	10.2	100.0	7.5	32.7
-1462	1949	2.5	12.3	10	200	100	62	10.2	100.0	7.5	19.4
-1463	1950	2.5	12.3	10	200	100	62	10.2	100.0	7.5	19.4
-1464	1951	2.5	12.3	10	200	100	62	10.2	100.0	7.5	19.4
-1465	1952	2.5	12.3	10	200	100	62	10.2	100.0	7.5	19.4
-1466	1953	2.5	12.3	10	200	100	62	10.2	100.0	7.5	19.4

Table A.15- Log data of Well 3 of Field B

BSL	Depth	Density	Porosity D	Porosity N	R_t	R_{xo}	DT	Porosity sonic	F	R_o	S_w
M	m	g/cc	%	%	ohm-m	ohm-m	µsec/ft	%		ohm-m	%
-1424	1900	2.35	21.1	16.5	35	35	70	15.9	36.7	2.8	28.1
-1425	1901	2.35	21.1	16.5	35	35	70	15.9	36.7	2.8	28.1
-1426	1902	2.35	21.1	16.5	35	35	70	15.9	36.7	2.8	28.1
-1427	1903	2.35	21.1	16.5	35	35	70	15.9	36.7	2.8	28.1
-1428	1904	2.35	21.1	16.5	35	35	70	15.9	36.7	2.8	28.1
-1429	1905	2.35	21.1	16.5	35	35	70	15.9	36.7	2.8	28.1
-1430	1906	2.35	21.1	16.5	35	35	70	15.9	36.7	2.8	28.1
-1431	1907	2.35	21.1	16.5	35	35	70	15.9	36.7	2.8	28.1
-1432	1908	2.35	21.1	16.5	35	35	70	15.9	36.7	2.8	28.1
-1433	1909	2.35	21.1	16.5	35	35	70	15.9	36.7	2.8	28.1
-1434	1910	2.35	21.1	16.5	35	35	70	15.9	36.7	2.8	28.1
-1435	1911	2.39	18.7	16.5	60	60	67	13.8	36.7	2.8	21.4
-1436	1912	2.39	18.7	16.5	60	60	67	13.8	36.7	2.8	21.4

Table A.15-Log data of Well 3 of Field B-Continued

BSL M	Depth m	Density g/cc	Porosity D %	Porosity N %	Rt ohm-m	Rxo ohm-m	DT µsec/ft	Porosity sonic %	F	Ro ohm-m	Sw %
-1437	1913	2.39	18.7	16.5	60	60	67	13.8	36.7	2.8	21.4
-1438	1914	2.39	18.7	18	60	60	67	13.8	30.9	2.3	19.6
-1438	1914	2.39	18.7	18	60	60	67	13.8	30.9	2.3	19.6
-1439	1915	2.39	18.7	18	60	60	67	13.8	30.9	2.3	19.6
-1440	1916	2.39	18.7	18	60	60	67	13.8	30.9	2.3	19.6
-1441	1917	2.39	18.7	18	60	60	67	13.8	30.9	2.3	19.6
-1442	1918	2.39	18.7	18	60	60	67	13.8	30.9	2.3	19.6
-1443	1919	2.39	18.7	18	60	60	67	13.8	30.9	2.3	19.6
-1444	1920	2.39	18.7	18	60	60	67	13.8	30.9	2.3	19.6
-1445	1921	2.39	18.7	18	60	60	67	13.8	30.9	2.3	19.6
-1446	1922	2.39	18.7	18	60	60	67	13.8	30.9	2.3	19.6
-1447	1923	2.39	18.7	18	60	60	67	13.8	30.9	2.3	19.6
-1448	1924	2.39	18.7	18	60	60	67	13.8	30.9	2.3	19.6

Table A.15- Log data of Well 3 of Field B- Continued

BSL M	Depth m	Density g/cc	Porosity D %	Porosity N %	Rt ohm-m	Rxo ohm-m	DT μsec/ft	Porosity sonic %	F	Ro ohm-m	Sw %
-1449	1925	2.39	18.7	18	60	60	67	13.8	30.9	2.3	19.6
-1450	1926	2.39	18.7	18	60	60	67	13.8	30.9	2.3	19.6
-1451	1927	2.39	18.7	18	60	60	67	13.8	30.9	2.3	19.6
-1452	1928	2.39	18.7	18	60	60	67	13.8	30.9	2.3	19.6

Table A.16 -Log data of Well 4 of Field B

BSL M	Depth m	Density g/cc	Porosity D %	Porosity N %	R_t ohm-m	R_{xo} ohm-m	DT μsec/ft	Porosity sonic %	F	R_o ohm-m	S_w %
-1500	1961	2.43	16.4	12	100	90	65	12.4	69.4	5.2	22.8
-1501	1962	2.43	16.4	12	80	60	65	12.4	69.4	5.2	25.5
-1502	1963	2.43	16.4	12	80	60	65	12.4	69.4	5.2	25.5
-1503	1964	2.43	16.4	14	60	40	65	12.4	51.0	3.8	25.3
-1504	1965	2.43	16.4	14	60	35	65	12.4	51.0	3.8	25.3
-1505	1966	2.43	16.4	14	60	40	65	12.4	51.0	3.8	25.3
-1506	1967	2.43	16.4	14	60	40	65	12.4	51.0	3.8	25.3
-1507	1968	2.43	16.4	14	60	40	65	12.4	51.0	3.8	25.3
-1508	1969	2.43	16.4	14	60	40	65	12.4	51.0	3.8	25.3
-1509	1970	2.43	16.4	14	50	30	65	12.4	51.0	3.8	27.7
-1510	1971	2.45	15.2	15	50	30	70	15.9	44.4	3.3	25.8
-1511	1972	2.35	21.1	18	28	18	70	15.9	30.9	2.3	28.8
-1512	1973	2.4	18.1	15	30	20	65	12.4	44.4	3.3	33.3
-1513	1974	2.45	15.2	10	70	50	65	12.4	100.0	7.5	32.7

Table A.16 -Log data of Well 4 of Field B-Continued

BSL M	Depth m	Density g/cc	Porosity D %	Porosity N %	Rt ohm-m	Rxo ohm-m	DT µsec/ft	Porosity sonic %	F	Ro ohm-m	Sw %
-1514	1975	2.44	15.8	13.5	40	30	65	12.4	54.9	4.1	32.1
-1515	1976	2.4	18.1	15	37	27	68	14.5	44.4	3.3	30.0
-1516	1977	2.35	21.1	15	35	25	70	15.9	44.4	3.3	30.9

Table A.17 -Log data of Well 5 of Field B

BSL	Depth	Density	Porosity D	Porosity N	R_t	R_{xo}	DT	Porosity sonic	F	R_o	S_w
M	m	g/cc	%	%	ohm-m	ohm-m	μsec/ft	%		ohm-m	%
-1479	1957	2.4	18.1	18	20	20	73	18.0	30.9	2.3	34.0
-1480	1958	2.4	18.1	18	18	18	73	18.0	30.9	2.3	35.9
-1481	1959	2.4	18.1	18	10	10	73	18.0	30.9	2.3	48.1
-1482	1960	2.4	18.1	18	15	15	73	18.0	30.9	2.3	39.3
-1483	1961	2.4	18.1	18	15	15	73	18.0	30.9	2.3	39.3
-1484	1962	2.4	18.1	18	15	15	73	18.0	30.9	2.3	39.3
-1485	1963	2.4	18.1	18	15	15	73	18.0	30.9	2.3	39.3
-1486	1964	2.4	18.1	18	20	18	73	18.0	30.9	2.3	34.0
-1487	1965	2.4	18.1	18	15	15	73	18.0	30.9	2.3	39.3
-1488	1966	2.4	18.1	18	15	15	73	18.0	30.9	2.3	39.3
-1489	1967	2.4	18.1	18	15	15	73	18.0	30.9	2.3	39.3
-1490	1968	2.4	18.1	18	15	15	73	18.0	30.9	2.3	39.3
-1491	1969	2.4	18.1	18	15	15	73	18.0	30.9	2.3	39.3

Table A.17 -Log data of Well 5 of Field B-Continued

BSL	Depth	Density	Porosity D	Porosity N	Rt	Rxo	DT	Porosity sonic	F	Ro	Sw
M	m	g/cc	%	%	ohm-m	ohm-m	μsec/ft	%		ohm-m	%
-1492	1970	2.4	18.1	18	20	15	73	18.0	30.9	2.3	34.0
-1493	1971	2.4	18.1	18	20	15	70	15.9	30.9	2.3	34.0
-1494	1972	2.4	18.1	18	20	15	70	15.9	30.9	2.3	34.0
-1495	1973	2.4	18.1	18	20	15	70	15.9	30.9	2.3	34.0
-1496	1974	2.4	18.1	18	20	15	70	15.9	30.9	2.3	34.0
-1497	1975	2.4	18.1	18	15	15	70	15.9	30.9	2.3	39.3
-1498	1976	2.4	18.1	18	15	15	70	15.9	30.9	2.3	39.3
-1499	1977	2.4	18.1	18	20	25	70	15.9	30.9	2.3	34.0
-1500	1978	2.4	18.1	18	16	16	70	15.9	30.9	2.3	38.0
-1501	1979	2.4	18.1	18	16	16	70	15.9	30.9	2.3	38.0
-1502	1980	2.4	18.1	18	16	16	70	15.9	30.9	2.3	38.0
-1503	1981	2.4	18.1	18	16	16	70	15.9	30.9	2.3	38.0

Table A.18 -Log data of Well 8 of Field B

BSL	Depth	Density	Porosity D	Porosity N	R_t	R_{xo}	DT	Porosity sonic	F	R_o	S_w
M	m	g/cc	%	%	ohm-m	ohm-m	µsec/ft	%		ohm-m	%
-1433	1899	2.5	12.3	12	90	40	65	12.4	69.4	5.2	24.1
-1434	1900	2.43	16.4	18	50	25	70	15.9	30.9	2.3	21.5
-1435	1901	2.42	17.0	18	30	20	73	18.0	30.9	2.3	27.8
-1436	1902	2.38	19.3	20	20	14	75	19.4	25.0	1.9	30.6
-1437	1903	2.38	19.3	21	15	14	78	21.6	22.7	1.7	33.7
-1438	1904	2.38	19.3	21	15	14	80	23.0	22.7	1.7	33.7
-1439	1905	2.35	21.1	21	15	14	80	23.0	22.7	1.7	33.7
-1440	1906	2.39	18.7	19	19	18	75	19.4	27.7	2.1	33.1
-1441	1907	2.4	18.1	18	15	18	75	19.4	30.9	2.3	39.3
-1442	1908	2.35	21.1	21	13	14	80	23.0	22.7	1.7	36.2
-1443	1909	2.35	21.1	21	13	15	77	20.8	22.7	1.7	36.2
-1444	1910	2.35	21.1	21	13	16	76	20.1	22.7	1.7	36.2
-1445	1911	2.38	19.3	21	14	15	75	19.4	22.7	1.7	34.9
-1446	1912	2.35	21.1	21	15	14	78	21.6	22.7	1.7	33.7

Table A.18-Log data of Well 8 of Field B-Continued

BSL	Depth	Density	Porosity D	Porosity N	Rt	Rxo	DT	Porosity sonic	F	Ro	Sw
M	m	g/cc	%	%	ohm-m	ohm-m	μsec/ft	%		ohm-m	%
-1447	1913	2.35	21.1	21	15	14	78	21.6	22.7	1.7	33.7
-1448	1914	2.38	19.3	19	15	14	75	19.4	27.7	2.1	37.2
-1449	1915	2.38	19.3	20	15	14	73	18.0	25.0	1.9	35.4
-1450	1916	2.38	19.3	19	15	14	73	18.0	27.7	2.1	37.2
-1451	1917	2.4	18.1	18	20	17	70	15.9	30.9	2.3	34.0
-1452	1918	2.4	18.1	18	23	20	70	15.9	30.9	2.3	31.7
-1453	1919	2.4	18.1	18	16	21	70	15.9	30.9	2.3	38.0
-1454	1920	2.44	15.8	16	17	30	67	13.8	39.1	2.9	41.5
-1455	1921	2.4	18.1	18	15	22	70	15.9	30.9	2.3	39.3
-1456	1922	2.38	19.3	19	10	20	75	19.4	27.7	2.1	45.6
-1457	1923	2.38	19.3	19	14	20	75	19.4	27.7	2.1	38.5
-1458	1924	2.38	19.3	19	14	20	72	17.3	27.7	2.1	38.5
-1459	1925	2.35	21.1	19	14	20	73	18.0	27.7	2.1	38.5

Table A.18-Log data of Well 8 of Field B-Continued

BSL	Depth	Density	Porosity D	Porosity N	Rt	Rxo	DT	Porosity sonic	F	Ro	Sw
M	m	g/cc	%	%	ohm-m	ohm-m	µsec/ft	%		ohm-m	%
-1460	1926	2.4	18.1	19	14	25	67	13.8	27.7	2.1	38.5
-1461	1927	2.44	15.8	17	20	30	70	15.9	34.6	2.6	36.0
-1462	1928	2.42	17.0	17	12	20	70	15.9	34.6	2.6	46.5
-1463	1929	2.42	17.0	17	16	25	70	15.9	34.6	2.6	40.3
-1464	1930	2.54	9.9	10	50	95	60	8.8	100.0	7.5	38.7
-1465	1931	2.55	9.4	12	40	60	60	8.8	69.4	5.2	36.1

Table A.19-Log data of Well 9 of Field B

BSL M	Depth m	Density g/cc	Porosity D %	Porosity N %	R_t ohm-m	R_{xo} ohm-m	DT μsec/ft	Porosity sonic %	F	R_o ohm-m	S_w %
-1453	1919	2.5	12.3	15	30	80	70	15.9	44.4	3.3	33.3
-1454	1920	2.5	12.3	15	30	50	70	15.9	44.4	3.3	33.3
-1455	1921	2.5	12.3	15	30	80	70	15.9	44.4	3.3	33.3
-1456	1922	2.41	17.5	15	30	50	70	15.9	44.4	3.3	33.3
-1457	1923	2.41	17.5	15	30	50	70	15.9	44.4	3.3	33.3
-1458	1924	2.45	15.2	15	30	50	70	15.9	44.4	3.3	33.3
-1459	1925	2.43	16.4	15	30	50	70	15.9	44.4	3.3	33.3
-1460	1926	2.43	16.4	15	25	40	70	15.9	44.4	3.3	36.5
-1461	1927	2.43	16.4	15	25	40	70	15.9	44.4	3.3	36.5
-1462	1928	2.43	16.4	15	25	40	70	15.9	44.4	3.3	36.5
-1463	1929	2.43	16.4	15	25	40	70	15.9	44.4	3.3	36.5
-1464	1930	2.45	15.2	15	25	40	70	15.9	44.4	3.3	36.5
-1465	1931	2.45	15.2	15	25	70	70	15.9	44.4	3.3	36.5
-1466	1932	2.45	15.2	15	25	70	70	15.9	44.4	3.3	36.5

Table A.19-Log data of Well 9 of Field B-Continued

BSL	Depth	Density	Porosity D	Porosity N	Rt	Rxo	DT	Porosity sonic	F	Ro	Sw
M	m	g/cc	%	%	ohm-m	ohm-m	μsec/ft	%		ohm-m	%
-1467	1933	2.45	15.2	15	25	70	70	15.9	44.4	3.3	36.5
-1468	1934	2.45	15.2	15	25	70	70	15.9	44.4	3.3	36.5
-1469	1935	2.43	16.4	15	25	30	70	15.9	44.4	3.3	36.5
-1470	1936	2.43	16.4	15	10	30	70	15.9	44.4	3.3	57.7
-1471	1937	2.43	16.4	15	10	30	70	15.9	44.4	3.3	57.7
-1472	1938	2.45	15.2	15	10	30	70	15.9	44.4	3.3	57.7
-1473	1939	2.48	13.5	15	10	40	70	15.9	44.4	3.3	57.7
-1474	1940	2.45	15.2	15	10	40	70	15.9	44.4	3.3	57.7
-1475	1941	2.42	17.0	15	10	30	70	15.9	44.4	3.3	57.7
-1476	1942	2.45	15.2	15	10	20	70	15.9	44.4	3.3	57.7

APPENDIX B

FIGURES

This appendix will contain figures of the data and the results.

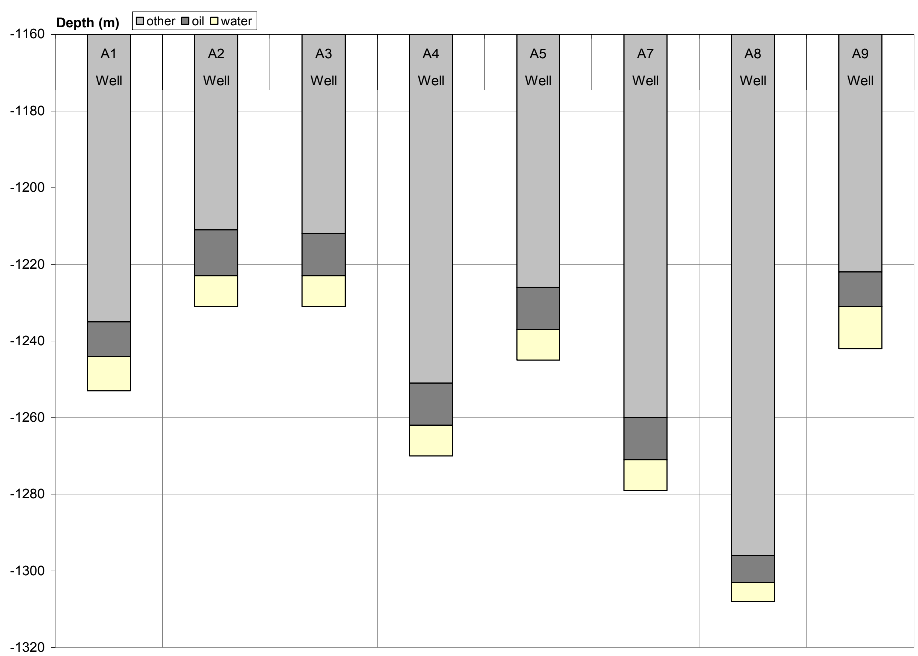

Figure B.1- Log Analysis Depth Plot for Field A

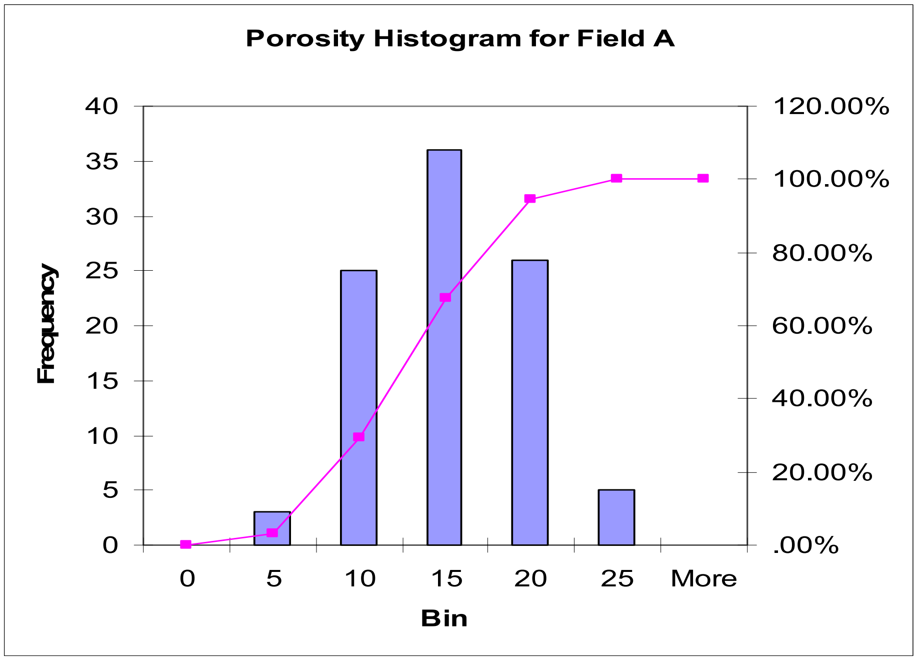

Figure B.2- Porosity Distribution Histogram for Field A

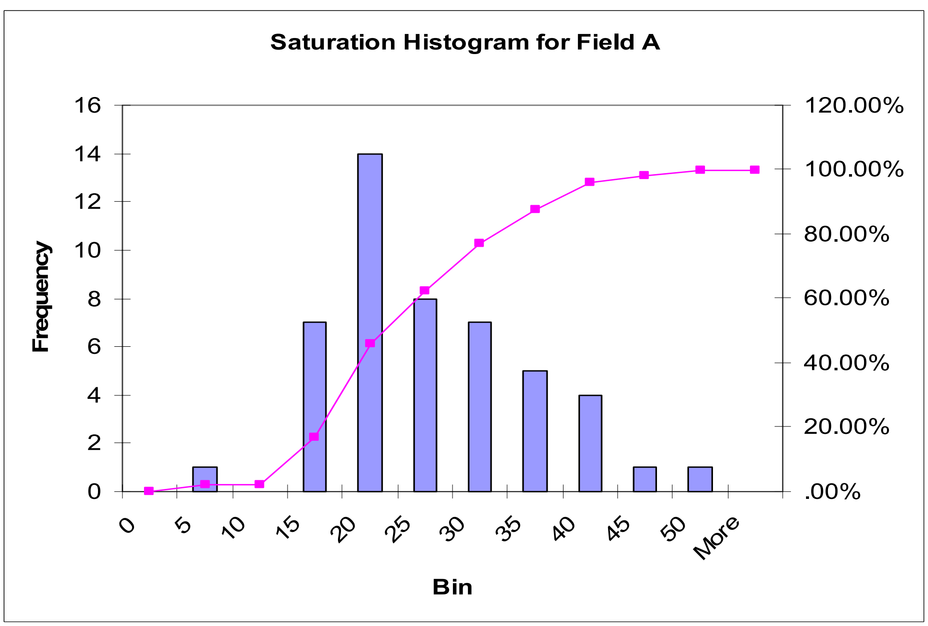

Figure B.3- Saturation Distribution Histogram for Field A

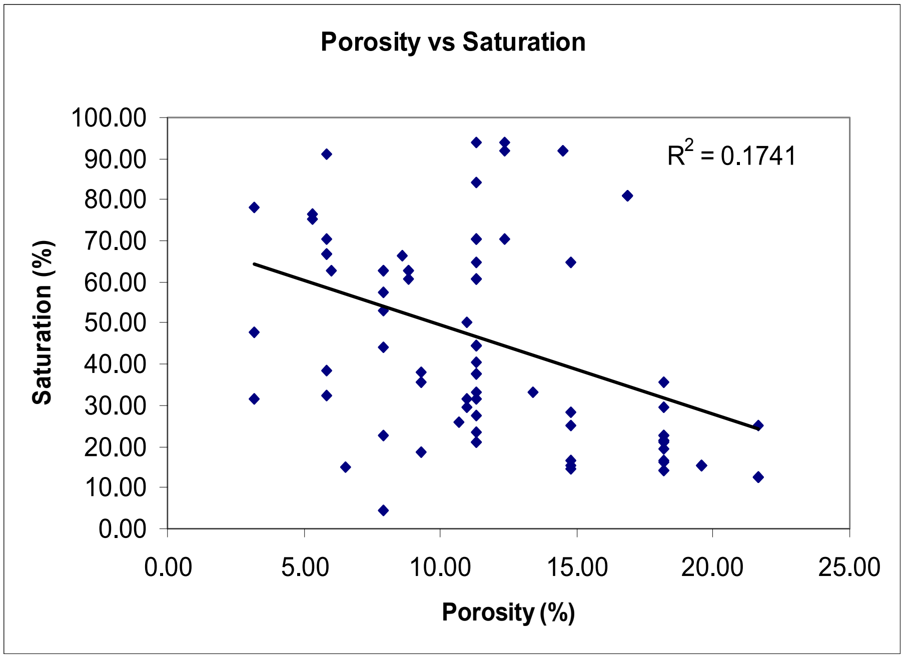

Figure B.4- Porosity vs. Saturation Graph for Field A

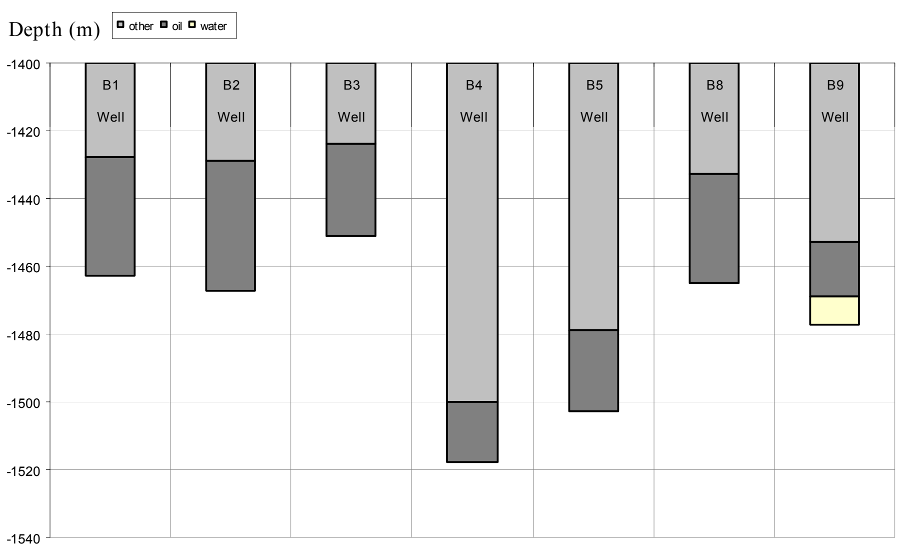

Figure B.5-Log Analysis Depth Plot for Field B

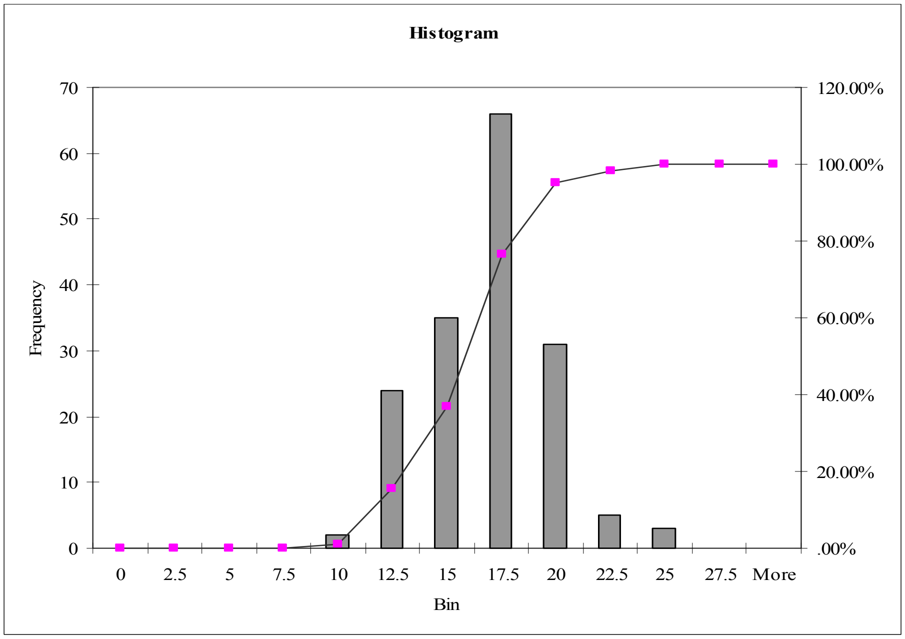

Figure B.6 - Porosity Distribution Histogram for Field B

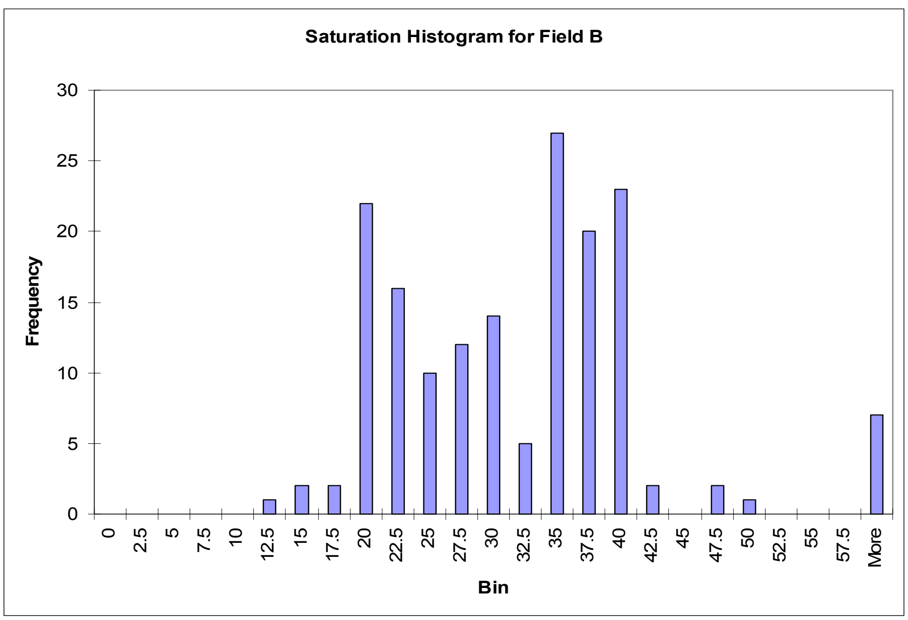

Figure B.7- Saturation Distribution Histogram for Field B

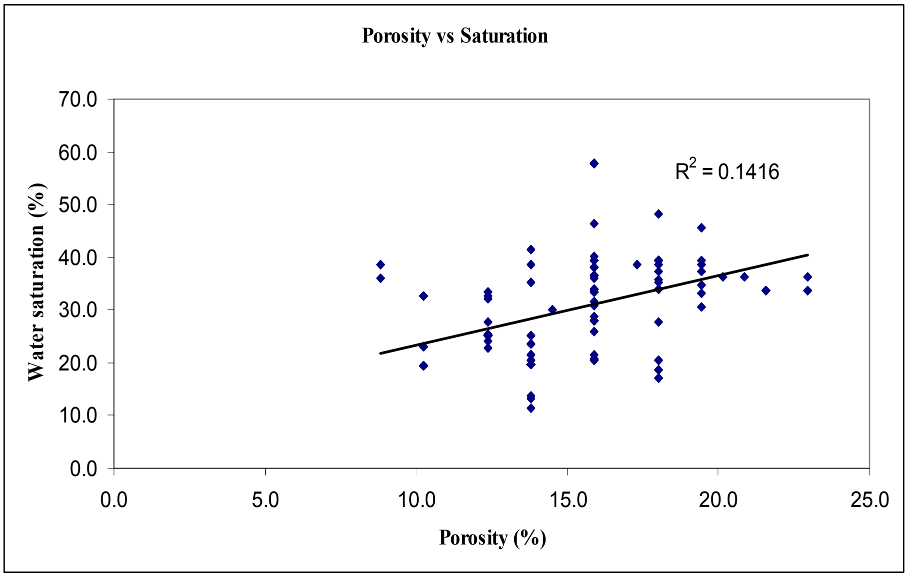

Figure B.8 - Porosity vs. Saturation Graph for Field B

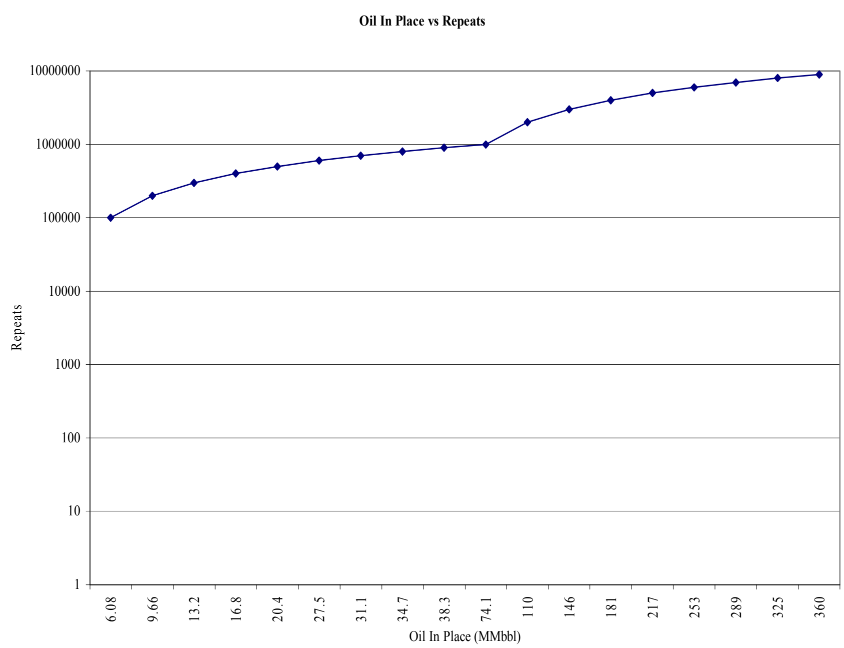

Figure B.9 - Oil in place vs. Repeats for Field B

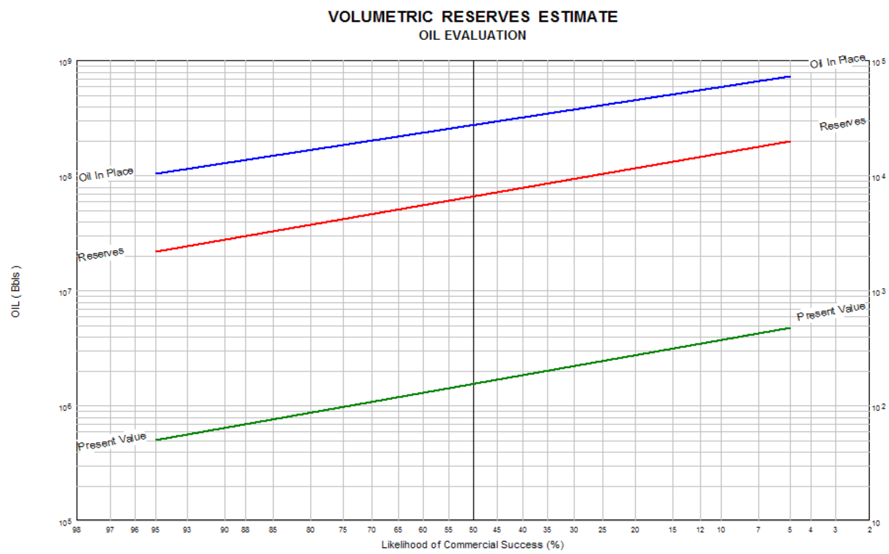

Figure B.10 – Effect of Porosity on Reserves Estimate for Field A

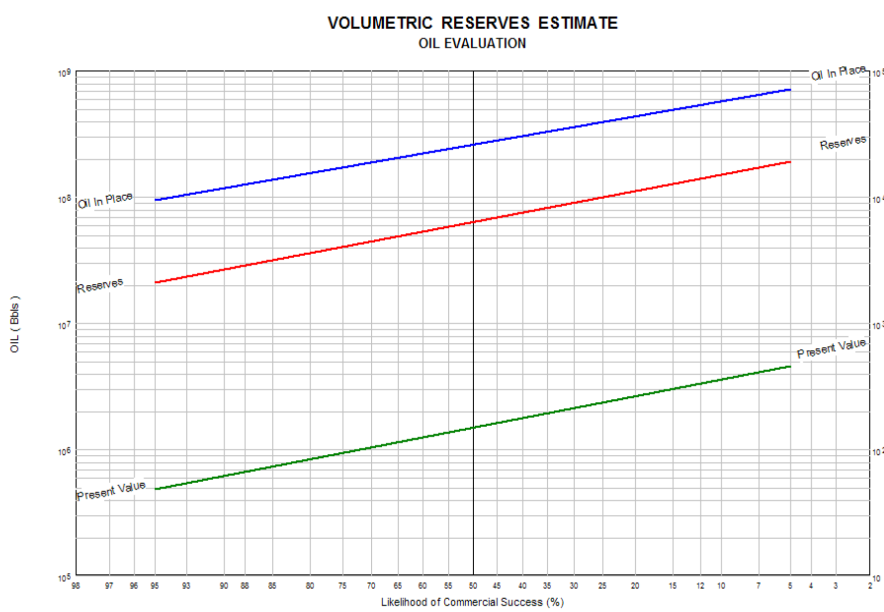

Figure B.11– Effect of Saturation on Reserves Estimate for Field A

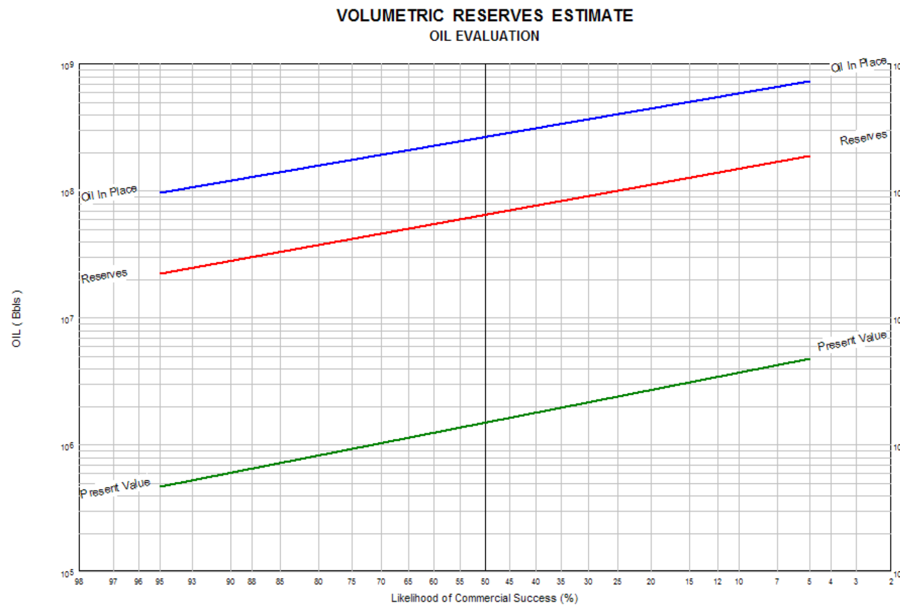

Figure B.12– Effect of Volume on Reserves Estimate for Field A

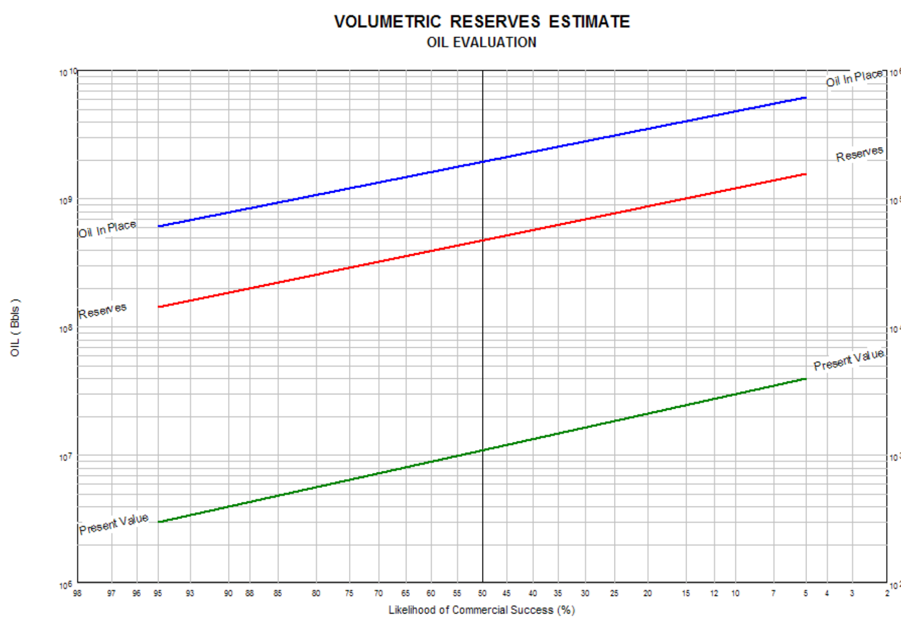

Figure B.13– Effect of Porosity on Reserves Estimate for Field B

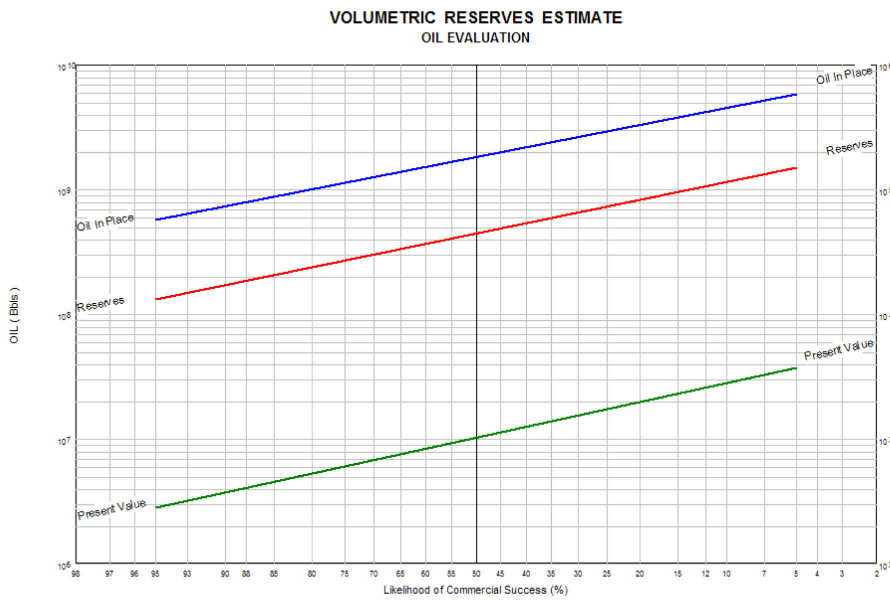

Figure B.14– Effect of Water Saturation on Reserves Estimate for Field B

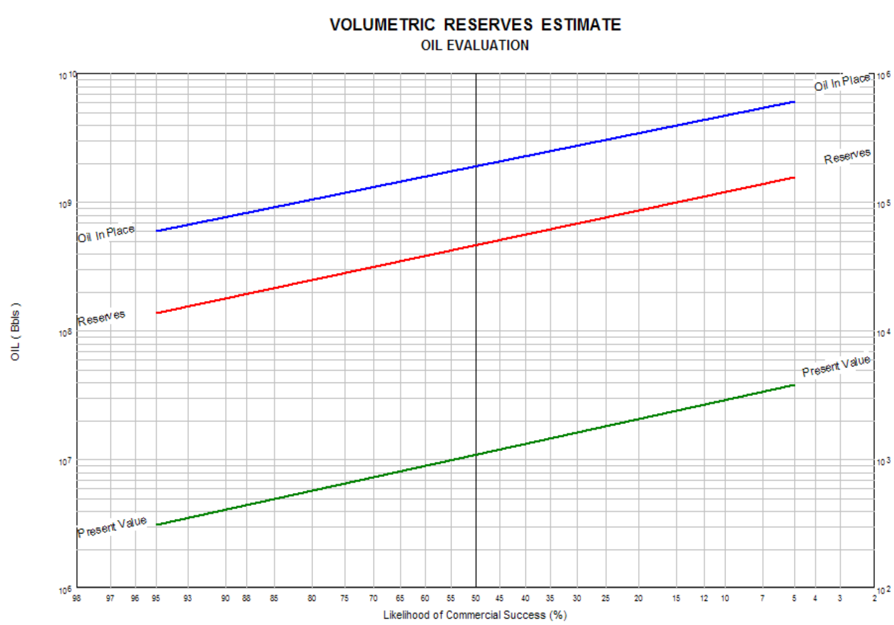

Figure B.15– Effect of Volume on Reserves Estimate for Field B

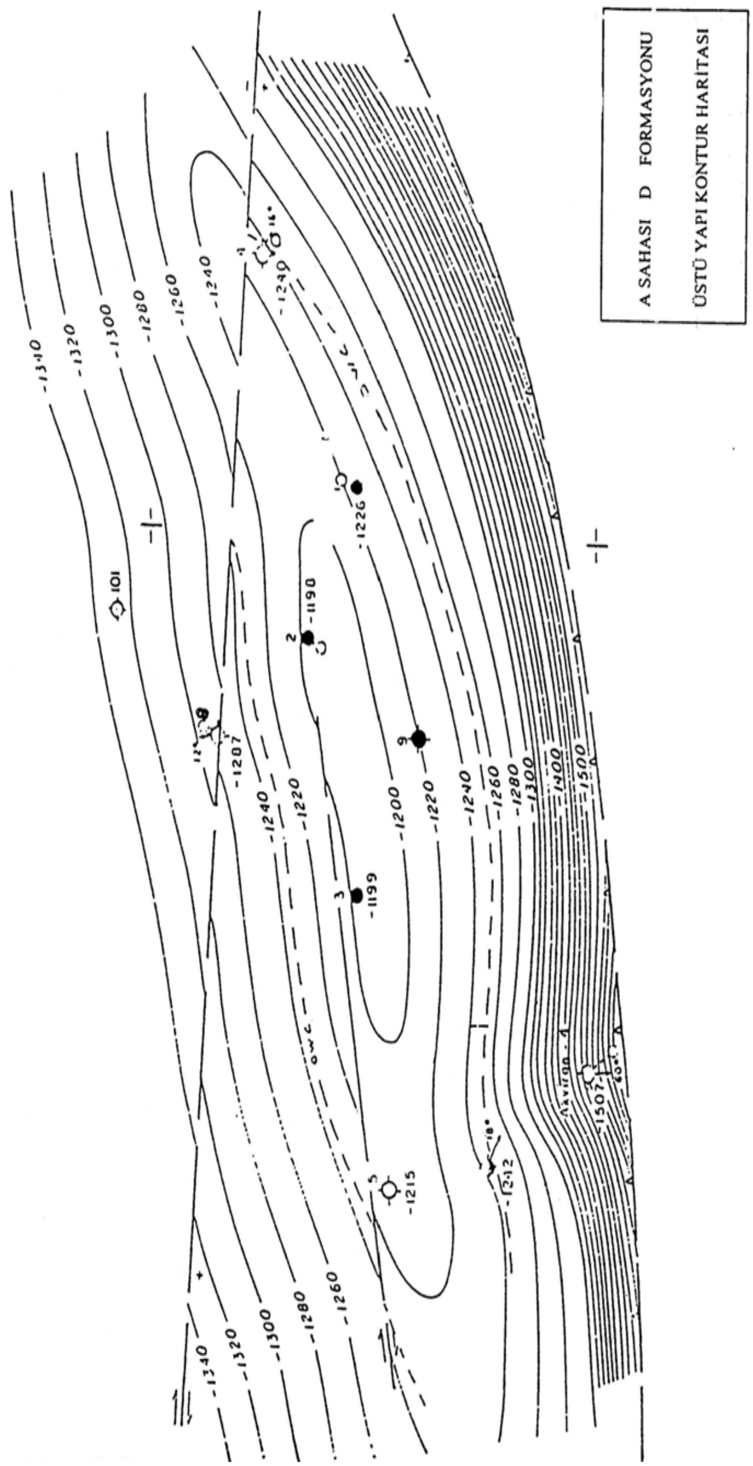

Figure B.16 - Structural Contour Map for Field A

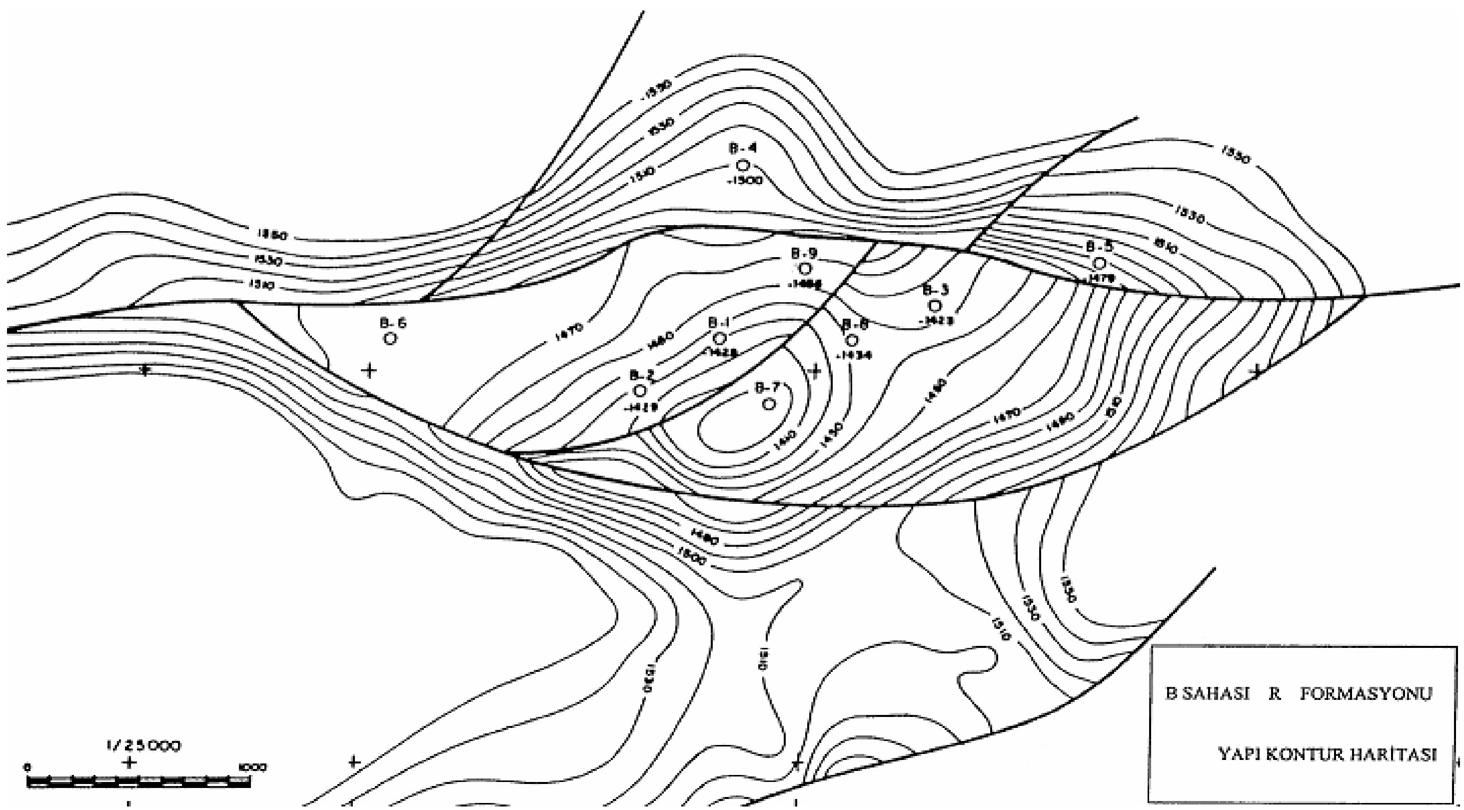

Figure B.17 - Structural Contour Map for Field B