CHAPTER I

INTRODUCTION AND LITERATURES

1.1 Introduction

Permeability is a measure of the ease in which a fluid flows through a rock. To be permeable, a rock must have interconnected porosity (pores, vugs, capillaries, fissures, or fractures). Greater porosity usually corresponds to greater permeability, but this is not always the case. Because other physical properties such as pore size, shape, continuity, and the amount of porosity, influence formation permeability as well.

Permeability can be obtained directly in laboratory (core analysis) or in reservoir (pressure transient analyses). Core analysis and in-situ permeability measurements using wellbore devices rely on the pressure-rate relationship in the estimation of permeability. Although permeability measurement from core analysis provides more accurate result, it is unable to measure at every depth due to the difficulties in obtaining the complete core sample and it is uneconomic. Pressure transient analyses provide a single value of permeability but account for the anisotropic nature of it. If these measurements are not available, permeability is estimated indirectly using rock properties acquired through well log measurements. Due to the abundance of reservoir data from well log measurements (porosity, and water saturation and etc.) which is measured at every feet of well depth, correlation of these rock properties to permeability has received a great deal of attention. Thus, permeability determination from well logging data can be made available in addition to the direct measurements from core and pressure transient analyses.

Generally, the range of permeability is extremely wide from less than 0.1 md to over 10,000 md. The lower limit of permeability for a commercial well depends on several factors such as thickness of pay zone, whether production is oil or gas, hydrocarbon viscosity, formation pressure, water saturation, value (price) of the oil or gas, well depth, and etc.

As mentioned above, the range of permeability is very wide and depends on several factors. Therefore, permeability estimation can be estimated from several methods. These include well logging, and well testing. The accuracy of the estimation varies with the quality and quantity of raw data available and estimation methods. Well logging is the widely used method to estimate permeability. Several correlations such as porosity, porosity and water saturation, and resistivity gradients of well logging data are used to indirectly estimate permeability. In this analysis, porosity data was used to estimate permeability values. Estimation of permeability is a very complex task. A poorly estimated permeability will make the reservoir simulation model inaccurate and unreliable, thus affecting the degree of success of oil and gas operations. Many efforts have been made by many researchers in order to establish a complex mathematical function, which relates permeability to other reservoir characteristics. This study has provided the suitable flow zone indicator (F_{zi}) to estimate permeability from following equation.

$$k = 1014\,(F_{zi})^2\,\frac{\Phi^3}{(1-\Phi)^2} \qquad (1.1)$$

$$F_{zi} = \frac{1}{\sqrt{F_s}\,\tau\,Sgv} \qquad (1.2)$$

where

k	=	permeability, md
F_{zi}	=	flow zone indicator
Φ	=	porosity, fraction
F_s	=	shape factor
τ	=	tortuousity
Sgv	=	surface area per unit grain volume, μm^{-1}

Equation (1.1) is developed from Kozeny (1927) and Carman (1937) for permeability determination from porosity. Flow zone indicator is known from a plot of permeability vs. $\Phi^3/(1-\Phi)^2$ on log-log coordinates when the slope of straight line equal to one. Actually, flow zone indicator from log-log plot of permeability vs. $\Phi^3/(1-\Phi)^2$ is difficult to estimate directly. Hence, hydraulic flow units (HFU) are applied for grouping flow zone indicator in the area under study. The suitable flow zone indicator is determined by comparing the results with core-determined permeability. In this study, geostatistical simulation is applied to simulate realization maps of well logging data (porosity data), the permeability equation can then be generated by using the suitable flow zone indicator. The simulated porosity and estimated permeability will be used as an input data into the reservoir simulated model.

For the application of permeability determination, in this study, the results of the production and recovery factor through reservoir simulation obtained from both using permeability from core analysis and from generated permeability equation will be observed. And, a comparison will be made based on these results.

1.2 Literature review

Geostatistical model is capable of expressing the nature of a property's variation and its disposition in a useful mathematical form and also of providing detailed distributions of physical properties. It also offers a collection of deterministic and statistical tools, aims at understanding and modeling spatial variability. Geostatistical method provides two kinds of prediction which are estimation and simulation. The Kriging estimation that is known as a linear estimation technique, provided unbiased estimates with minimum variances. It is deterministic leading to a single reservoir model which has smooth estimate values. A smooth map is appropriate for showing the global trends. The presence of a few very high and low values tend to inflate local average, and simple interpolation may mislead interpretation and decision. In that case, the linear estimators may not be the best to reflect the degree of local variability.

Simulation technique was initially developed to correct for the smoothing effect shown on maps produced by Kriging estimation. It composes of two steps: (1) calculation of an unconditionally simulated value at each point in an area and (2) adjustment of these values to honor sampled values. Damayanti and et al. (1996) examined the effect on predicted oil recovery of using polygonal weighting, linear interpolation, Kriging, and Sequential Gaussian Simulation (SGS) to estimate key reservoir properties for grid blocks without wells. Simulations using SGS generated input data tended to have the highest recoveries followed by simulations with data generated using Kriging, linear interpolation and polygonal weighting. The reservoir simulation results illustrate the need to use the best reservoir description in reservoir engineering analysis. In addition Deutsch and et al. (2002) used geostatistical algorithms to modify three requirements. First, direct simulation must be used in place of the more common Gaussian simulation. This is required because reservoir properties do not average linearly after Gaussian transformation. In addition, averaging is required because each grid block potentially has a different volume. Second, volume averaged variogram or covariance values are between two arbitrary blocks. These must be calculated quickly and efficiently. Third, to maintain a reasonable speed of geostatistical simulation on unstructured grids a customized search and a non-stationary covariance lookup table of the average covariance between blocks is required. Finally, directional permeability requires a special transformation to account for the nature of averaging.

This study involves not only the application of geostatistical model, but also Kozeny-Carman equation to determine permeability from porosity. There are several methods to determine permeability in uncored wells. Abbaszadeh and et al. (1995) presented an improved technique based on the concept of hydraulic flow units to calculate permeability distribution in uncored wells. The method is applied to two heterogeneous reservoirs, a carbonate formation, and a laminated sandstone formation. Comparisons of permeabilities calculated by the hydraulic flow unit approach and the other conventional techniques are provided demonstrating the usefulness of the hydraulic flow unit method. Mohaghegh and et al. (1995) discussed and compared three different approaches for permeability determination from well logs from a practical point of view. The three methods, empirical, statistical, and the recently introduced "virtual measurement," make use of empirically determined models, multiple variable regression, and artificial neural networks, respectively. They showed that virtual measurement performs better than multi regression method in prediction permeability from well logs in new wells. They also showed that this characteristic of virtual measurement technique is not accidental and works for any combination of wells in model development and testing. Soto and et al. (2001) presented a novel method. The hybrid soft computing techniques were used for permeability predictions by estimating flow zone indicator first. To classify flow zone indicator, hydraulic flow unit was used. The technique is known as adaptive network-based fuzzy inference systems or ANFIS, and is based on adaptive neural networks and fuzzy inference systems (FIS). The results showed that hybrid soft computing techniques offer powerful tools for further improving permeability predictions. In 2003, Shang and et al. developed a new permeability estimation method using equivalent rock element model (EREM) which consists of formation resistivity factor, porosity and irreducible water saturation. The purpose is to compare this method with the four existing methods: porosity versus logarithm of permeability, Kozeny (1927) – Carman (1937), Wyllie-Rose (1950), and Timur (1968) methods. The main conclusion indicated that, for all the core samples applied to, the purposed EREM model-based method consistently produced correlations superior to the four existing methods.

1.3 Thesis outline

This thesis outline consists of five chapters.

Chapter I outlines introduction and previous works concerning with this study. The previous works is related to two subjects: (1) geostatistical model by using Sequential Gaussian Simulation which has been conducted in order to estimate key reservoir properties for grid blocks without wells and populate directly the unstructured grid and (2) permeability determination from uncored wells.

Chapter II describes the theories and concepts used in this study including geostatistics, cross validation, Sequential Gaussian Simulation, and permeability equation from porosity. This chapter is divided into 2 sections, which are presented as follows:

- Section 2.1 introduces the geostatistical method. The theory of geostatistics is first presented. After that, a procedure to quantify the spatial variability structure of variable is introduced in terms of variogram analysis. Next, cross validation is presented to verify the variogram model. Then, the Sequential Gaussian Simulation algorithm is described and the procedure to simulate the variable value at each interested location is presented.

- Section 2.2 presents the permeability equation. A brief theory of Kozeny-Carman equation is introduced, which plays an important role in this study. This part includes flow zone indicator and hydraulic flow unit that concerns with Kozeny-Carman equation.

Chapter III discusses data preparation and stochastic simulation, including information of data set, statistical analysis, structural analysis, cross validation and Sequential Gaussian Simulation. Stanford Geostatistical Modeling Software (SGeMS) is used in this chapter.

Chapter IV presents the permeability equation obtained from the porosity and permeability data of core analysis. And, a comparison of production performance through reservoir simulation of the calculated permeability obtained from the different simulated porosity is presented.

Chapter V summarizes the results from the study. The conclusions and recommendations are also presented.