PERMEABILITY PREDICTION IN CARBONATE RESERVOIR (IRANIAN RESERVOIR)

By

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CERTIFICATION OF APPROVAL

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Approved by,

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CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

MOHSEN POURMOHAMMAD SHAHVAR

DEDICATION

I dedicate this thesis to the Almighty Allah for His Pleasure and Mercy. It is also dedicated to the Holy Prophet Muhammad (PBUH), whom Allah created as guidance to mankind. I extend my dedication further to my teachers and friends. And finally, to my family for their unending love and support

ACKNOWLEDGEMENTS

In the name of the Almighty ALLAH, the Beneficent, the Merciful. Boundless Praise be to Allah, who gives unending blessings to His creations. He is the one and only Creator of the World in its entirety and the Universe. May ALLAH richly bless the Prophet Hazrat Muhammad (PBUH) as his teachings and life examples will be an everlasting guidance for all of humanity. For my enjoyment, support and success throughout the time of completing my thesis, I can never express enough my deepest gratitude to ALLAH.

ABSTRACT

With the application of modified equation a new permeability equation is developed from porosity and irreducible water saturation. Sedimentary rocks are often tested for their correlation between porosity, (Ø), and permeability, (K). A general trend of increase in permeability with porosity can be expected. Different affections such as, grain size, packing, compaction, and solution or dissolution can influence the relationship between porosity and permeability. The prediction of permeability in heterogeneous carbonate reservoir from well log data is not very accurate. When using conventional core analysis (RCA) and special core analysis (SCAL) a new modified equation becomes present. The empirical equation is used as a base model, evaluated by Wyllie and Rose (1950) which is related to permeability, porosity, and irreducible water saturation. Various empirical models such as, Timur 1968, Tixier 1949 are used to predict permeability from log data for sandstone reservoirs worldwide. In addition to existent proposed equations, we propose an additional equation that also uses laboratory data.

The equation is presented, related K, Ø and Swi in a carbonate reservoir in the Southwest of Iran known as Sarvak and Fahliyan formations. This equation was obtained by calculating the coefficients of general Wyllie and Rose model. Nonlinear model was derived for that relationship and by curve fitting, the new coefficients were calculated.

Calculated permeability was compared to values of new modified equation and lab permeability of core samples. This study empirical equation exhibits that distribution of calculated permeability versus porosity, plays an important role in establishing an accurate correlation between permeability, porosity and irreducible water saturation. Deterministic equation can be used for reservoirs which are similar to the geological features of our study area. Finally, according to modified equation and other empirical equations, it’s shown that this study modified equation with $R^2 \geq 0.78$ is acceptable.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

CHAPTER 1

INTRODUCTION

1.1 Motivation and Introduction

Permeability is one of the most important petroleum reservoir properties and also it is so difficult to predict accurate. The permeability of a rock depends on its effective porosity, consequently, it is affected by the rock grain size, grain shape, grain size distribution (sorting), grain packing, and the degree of consolidation and cementation.

The type of clay or cementing material between grains also affects permeability, especially where fresh water is present. Some clays, particularly smectites (bentonites) and montmorillonites swell in fresh water and have tendency to partially or completely block the pore spaces. (Tiab et al-2004)

Petroleum reservoirs can have primary permeability, which is also known as the matrix permeability, and secondary permeability. Matrix permeability originated at the time of deposition and lithification (hardening) of sedimentary rocks. Secondary permeability resulted from the alteration of the rock matrix by compaction, cementation, fracturing, and solution. (Tiab-2004)

Finding the best equation to find permeability without experimenting is highly appreciated by engineers nowadays, although for sandstone many empirical calculation were obtained, for carbonate still no stable and reliable calculation is found which is suitable for all carbonate reservoirs. Well log data and core analysis are the common way to find the equation which was used before for sandstone.

Muscat (1949) pointed out that no matter how complete the coring and precise the data, one is still limited to an examination and study of rock samples which can constitute at the most, a fraction of the total reservoir volume only of the order of 0.0001%. One should keep this is mind as one compares core-derived permeability to permeability derived from, for example, well testing which can have a large volume of investigation permeability measurement by direct core analysis is documented in the American Petroleum Institute (1960) reference.

1.2 Problem statement

It is well known among the petroleum community that in order to have a complete and accurate reservoir characterization, it is essential to have means to obtain values of permeability for the particular field in study.

Until 1990, there was no agreement among petroleum engineers and geologists whether or not there is a correlation between porosity and permeability. And how can there be a correlation between porosity and permeability in carbonate reservoir. In 1990, Chilingar et al. solved this problem by introducing two additional parameters i.e., irreducible fluid saturation and specific surface area for micro-fractured dolomite reservoir (Chilingar et al. 2008).

Thus, for carbonate reservoir still no reliable equation is obtained and the author believe that there should be some researches in specific carbonate reservoir but most of them used well log data which in further chapter will be written and will not be more accurate. Finding the best and exact equation for predicting permeability in carbonate reservoir is not evaluated yet and researchers are trying to generate one formula for all kind of carbonate reservoir.

Using core data and correlating one equation from data is more prefer to obtain one accurate equation to predict permeability, by considering more parameters which have affect on permeability especially in carbonate reservoir.

1.3 Objective of study

1- Investigating permeability prediction in carbonate reservoir
2- Find the best correlation depending upon the given data for carbonate reservoir
3- Modify the chosen correlation for carbonate reservoir

1.4 Scope of study

This research is focused on predicting permeability in Iranian carbonate reservoir which is located in south west of Iran close to Iran-Iraq border, and all core samples were taken from FAHLIYAN, SARVAK and GAVDAN formation, and modifying equation which is using for sandstone reservoir and obtained by Wyllie and Rose and modified by Timur, Tixier and etc.

This research contains the results of core laboratory experiments on 159m of cores from SARVAK and 81.4m of cores from FAHLIYAN formations. It includes the petrophysical parameters at ambient conditions and absolute permeability with gas-corrected for klinkenberg effect.

When the sufficient data (Log, Test or Core data of well) is available, using this modified equation is recommended.

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CHAPTER 2

LITERATURE REVIEW

2.1 Regional Geology

The study field shows a N-S Arabian trend in the main part of the structure (Hosseinieh area) and a weak NW-SE influence in the northern closure (Kushk area) as shown in Figure 2.1. Confirmation that study field is a predominantly non-fractured (or fractured) reservoir shall be investigated further. The current base case assumes depositional facies will have the greatest influence on reservoir characterisation. (Fereydoun Ghazban, 2007)

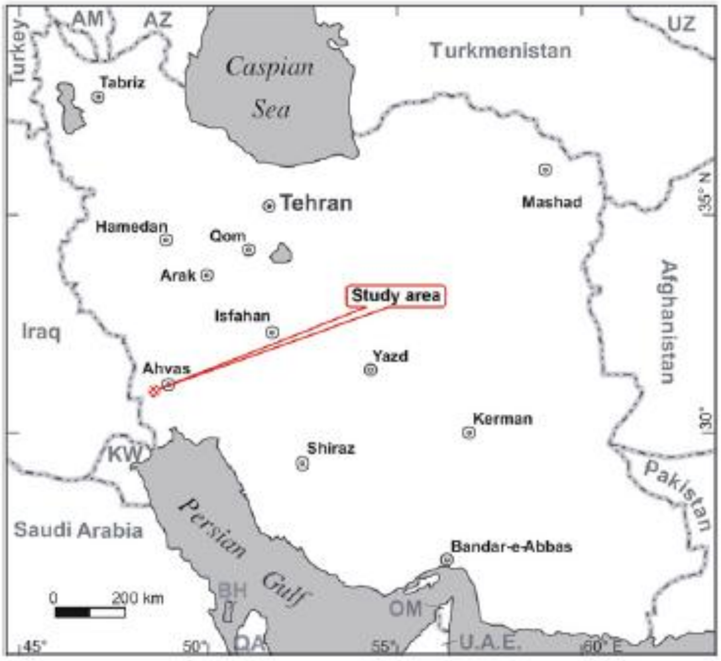


Figure 2.1: Place of Research Area

2.1.1 Sarvak Formation

The late Cretaceous Sarvak Formation mainly consists of shallow-marine massive carbonates and is one of two main oil reservoirs in study field. Regionally, the Sarvak Formation is developed in two major facies:

1. Massive platform carbonates containing rudists, gastropods, pelecypods and rich microfauna;
2. A deeper-marine basinal facies of thinner-bedded, fine grained, dark coloured argillaceous Oligostegina limestone with a pelagic microfauna.

The study field area is located on the platform close to its northeast edge, between the excellent and prolific Mishrif reservoirs of Halfayah, Majnoon and West Qurna in Iraq, and the tight low-energy basinal facies of Jufeyr in Iran. The apparent discrepancy in very large column heights versus the structural closure is likely due to stacked reservoirs. At some levels, different pressures, fluid levels and wide range in production tests, indicate that the study field is much more complex than can be currently explained by the limited available well data. (SaadatiNejad et al, 2009)

The Sarvak Formation is named after Tange-e-Sarvak in Kuh-e-Bangestan in Khuzestan region. In its type section, the formation consists of three main limestone units 832 meters(Fereydoun Ghazban,2007) as its shown in Figure 2.2.

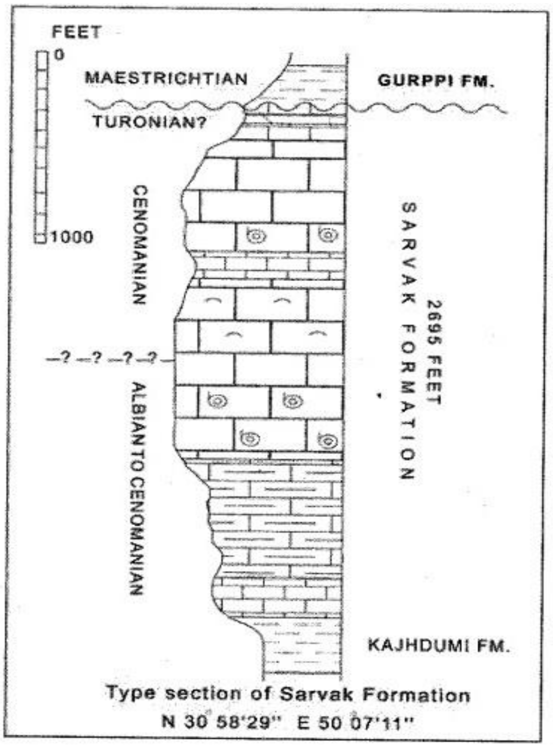


Figure 2.2: General Stratigraphic column of the Sarvak Formation in its type locality in Kuh-e-Bangestan (modified from Motiei, 1993)

2.1.2 L.Fahliyan Formation

The L.Fahliyan, nearly 600 m thick, is of early Cretaceous age. It is regionally known as a massive oolitic to pellety limestone, and is one of the two main oil reservoirs of the study field. In an adjacent field, the L.Fahliyan formation has been divided into Upper and Lower members across an over-pressure boundary and general facies differences. A similar pressure boundary and correlatable individual over-pressure trends, also exists in study field. A gross hydrocarbon bearing column of ca. 330 m has been penetrated in study field . This is considerably larger than the mapped structural closure (SaadatiNejad et al, 2009).

2.1.3 Gadvan Formation

Gadvan formation of lower cretaceous (upper Barremian to lower Aptian) age consists of marl and shale, and associated pelecypod-bearing argillaceous limestone, resting gradationally on Fahliyan formation. Gadvan Formation in southern Iran is 218 meters thick. It consists of shallow marine to neritic marls made up of massive, crystalline, occasionally chalky limestones. The contact is characterized by a zone of abundance of iron oxide nodules. In comparison to the underlying formation there is a high percentage of clay. The formation is light grey to whitish yellow, while the strata are thin to medium bedded. The formation is not well exposed because of coverage by slum blocks and screen material from overlying Dariyan Formation. (Fereydoun Ghazban, 2007)

The early Cretaceous Gadvan formation was found to be oil-bearing in wells (the most crestally located wells). As interpreted from study field completion logs, and nearby field and regional data, this formation consists of shoreface to shallow-marine sandstones, siltstones and shales, and shallow water carbonates.

2.2 Permeability Estimation in Carbonate Reservoir

There are two important and vital parameters porosity and permeability which shows the presence of oil. In particular, reservoir permeability is a good indicator of the flow rates that are obtained from a well. So permeability prediction is having a great amount of significance.

Permeability is the ability of a rock that permits fluids to flow through its pore system. It is a vital and important factor as for as production of fluids from the reservoir is concerned. The Controls on porosity are tacit, and methods are now well established for porosity estimation, but on the other hand understanding of the factors that are controlling permeability is not that advanced yet.

Data that is available for permeability prediction differs with the stage of a reservoir evaluation. An assessment of permeability at wild cat stage before drilling is necessary to limit the potential economic return. This is normally based on regional porosity-permeability-depth that trends together with sedimentological information; some other data such as burial history data may also be added. In appraisal and development, a thorough explanation of permeability is requisite. Direct reservoir characteristics measurements from seismic reflection data, wireline logs, well tests, and core samples will be accessible. During these stages, prediction includes combination of permeability measurements having information on reservoir sedimentology, jointly with seismic reflection and wireline log data, in order to fill the breach that lies between wells and fabricate an overall reservoir description.

2.2.1 Determination of Permeability

Permeability determination involves measurements on core samples and to determine permeability with the methods outlined in API RP 40. (API RP 40,1998). The main permeability estimation and calculation techniques are wire line tool analysis (including RFT method), well testing, and laboratory analysis of core samples.

2.2.1.1 Wireline Measurements

Five methods are established for obtaining permeability from wireline tool measurements:

- Empirical correlation of permeability with porosity,$\emptyset$, and intergranular surface area.
- Measurement of producible formation fluid with the nuclear magnetism log (NML)
- Estimate of mineral concentration by the geochemical logging tool (GLT)
- Correlation of permeability with Stoneley wave velocity by acoustic logging tools
- Pressure/Time measurement of formation fluids with the RFT tool

NML Measurements:

The NML provides two specific products that can be related to formation permeability.(Neuman,C.h et al,1982) . One is the free-fluid index, I_{ff}, a measure of movable fluid (oil and water but not gas). The other is spin-lattice relaxation time t_L, the time constant involving the alignment of proton spin axes along magnetic fields. I_{ff} typically is obtained by applying a large, polarizing magnetic field to the formation and then turning it off. Signal decay in solids and bound fluids is too rapid for detection with the NML tool. Only decay in the free fluid can be measured, and I_{ff} is proportional to the number of protons in free fluid. Thus, I_{ff} is related to S_{wi} by

$$S_{wi}= 1 - (I_{ff}/\emptyset) \qquad \text{Eq(1)}$$

This can be applied to Kozeny correlation. T_L is a property of the rock and fluid wetting its pore surfaces and thus relates to pore size. Because permeability is proportional to the square of pore size, it is reasonable to assume (Scotts,1966 and Kenyon, W.E. et al,1988) that k is proportional to t_L^2. On the basis of a study of 80 sandstone cores from wells worldwide, Kenyon a al.(Kenyon, W.E. et al,1988) related t_L to k as follows:

$$k=1.6*10^{-9}t_L^{2.3}\emptyset^{4.3} \qquad \text{Eq(2)}$$

Where:

K: Permeability

$T_{l:}$ Property of the Rock

∅: Porosity

NML responses in carbonates differ from those in sandstones. It is not surprising, therefore, that a reasonable correlation between t_L and permeability has been found in only a few carbonates. (Densest. J.R et al,1987)

GLT Measurements

GLT measures the concentrations of 10 elements in a formation by borehole nuclear spectrometry. The basis for obtaining permeability from elemental concentrations is that any changes in mineralogy are accompanied by changes in the size, shape, and morphology of rock grains.(Herron, M,1987) These changes affect the pore system geometry, which directly influences permeability.

After Finding exact size and geology of rock, and after that plot versus porosity permeability is findable.

Stoneley Ware Attenuation and Dispersion

The Stoneley wave is acoustic energy that travels predominantly along the bore-hole wall. It is generated when an acoustic pulse from a sonic logging tool meets the interface between the borehole wall and the borehole fluid (White, J.E,1983 and Chang. S.et al,1987). If the borehole crosses a permeable formation, the Stoneley wave attenuates by moving fluid in the pores. It is also dispersed, meaning that different frequency components are slowed at different rates. This attenuation and dispersion relates to the formation's permeability, matrix or natural fractures. Although correlations between Stoneley behavior and permeability have been observed in the field, a quantitative prediction of permeability from Stoneley energy measurements has eluded laves-tigators. Various investigations, how-ever, continue to use Stoneley waves to directly measure permeability and as a fracture indicator. (Cheruvier, E. et al, 1987)

Stoneley-wave data are typically presented as both:

- An interval transit time, Δtt

- As a ratio of the amplitudes for the two receivers used

Both traces have been shown to correlate well with permeability changes and compare well with core data, when it is available. Stoneley-wave amplitude can be computed and used in conjunction with the slowness and the signatures to analyze dispersion and attenuation characteristics. Use of the attenuation (center-frequency shift) and dispersion (travel-time delay) provide good permeability indication and better quality control for permeability estimation.

Wave-separation processing minimizes the effects of nonpermeability-related influences (e.g., road noise and borehole scattering) and yields reflectance logs for the direct and reflected Stoneley-wave data. The center-frequency log for the reflected wave data characterizes the Stoneley-wave attenuation and can be used to indicate:

- Fractures
- Vugs
- Bed boundaries

The center-frequency log for the direct (transmitted) data is used to estimate formation permeability. Knowledge of the formation-fluid properties (viscosity and compressibility from core or NMR) enables quantitative estimates. Without this information log-derived permeability estimates are only qualitative.

These models require sophisticated computer processing. A simplified, field-oriented technique based on Stoneley amplitude (Canady et al,2005) has so far provided good results in ideal conditions and when calibrated to core or nuclear magnetic resonance (NMR) data.

The Stoneley wave measures total permeability and NMR measures vuggy permeability. A comparison of these two measurements in carbonate formations makes it possible to evaluate the permeability contributions arising from fractures and vugs. (Tang et al,1998)

RFT Measurements

The formation-tester tool samples reservoir fluids and measures formation pressure vs. time at specific depth stations. With the RFT three sets of data can be collected to quantify permeability. The first two (in association with pretest) are relatively quick, and the last one, called super flow, can last several minutes. The tool is first positioned to allow mud filtrate and formation fluids to fill a first sample chamber at a controlled, low flow rate (first pretest). This step is followed immediately by the filling of a second sample chamber at a controlled, high flow rate (second pretest). This phase of the test is called drawdown. The subsequent phase of the test, buildup, is a measurement of increasing pressure once the chambers are filled. The final phase, super flow, involves long-term drawdown while measuring the cumulative volume and transient pressures. Both the drawdown and buildup tests pro-vide a permeability value that is often reflective of near-wellbore fluid movement. To calculate permeability, the pressure derivative is first plotted to identify the flow regime and is followed by specialized plots. For drawdown pressures. where normal (10- cm8) pretest chambers are used the flow pattern is typically hemispherical, a mixture of horizontal and vertical flow with a bias to horizontal. Buildup permeability typically illustrates a spherical flow pattern, a mixture of horizontal and vertical flow with a bias to the vertical. Buildup permeability measurements are reliable only in low-permeability formations (<50 md) because of limitations in the resolution of the pressure measurements. During superflow, the pressure data are history-matched, taking into account the cumulative fluid production. Because of increased fluid production, permeabilities estimated during superflow correspond with the hydrocarbon-related effective permeability more than with the invaded fluid movement.(Bourdet D et al,1987)

To calculate permeability, the pressure derivative is first plotted to identify the flow regime and is followed by specialized plots and equations.

2.2.1.2 Well Testing

Procedure to find the permeability can be classified in three categories in well testing:

1-Short-Term test involving Drill Stem Test (DST), Impulse^{SM} testing, and transient-rate and pressure testing(TRAP^{SM}) where the investigation radius is limited.

2-Conventional tests-classic pressure drawdown (or injection test) and pressure Buildup (or falloff test)

3-Advanced test involving methods beyond the traditional single-layer horizontal-permeability evaluation, consisting of layered reservoir testing (schlumberger cased hole log interpretation principles (Application Schlumberger, Houston (1989)).

- **Short-Term Testing**

Short-term testing consist of techniques which require a relatively short test period; so the radius of investigation is relatively shallow (Typically<100ft).

DST consists of 2 drawdowns with following buildups. Interpretation steps are similar to those for RFT buildups and drawdowns (pressure derivate for flow-regime identification and specialized plots to estimate permeability). Due to have short time for testing, permeability estimation of DST can be covered by wellbore storage and drilling mud invasion. (Earlougher,1977).

Impulse testing allows one to test the well after a perforation without making an extra trip. The test data can be type curved matched and/or plotted as a rate-normalized Horner plot to calculate permeability.

Trap testing uses the transient downhole pressure and rate. The elimination of wellbore storage is used here to shorten the test duration. Even though the test takes less than a couple of hours, calculation of formation permeability is typically unaffected by near-wellbore damage.

- **Conventional Testing**

There are many variations of conventional well-test methods. For the past 40 years, the two most straight forward ways to measure permeability have been drawdown and buildup tests, preformed in fundamentally the same manner as RFT drawdown and buildup tests.

The goal is to find the transmissivity (Kh/μ) and h, thickness is determined at the borehole and k can be estimated.

- **Advanced Test Techniques**

These techniques go beyond the traditional single layer horizontal permeability evaluation.

    - *Layered Reservoir Testing*. With use of regular production logging tools, one can evaluate the permeability of individual layers by imposing a transient at each layer and measuring the pressure and flow-rate response.
    - *Vertical Interference Testing*. Vertical interference testing permits the assessment of presence and degree of vertical communication and vertical permeability.

- *Multiwell Interference Testing*. This can yield average permeability thickness value and indicate the horizontal extent of the reservoir and whether the two wells are in horizontal communication.

Finding the changes in pressure versus time is the goal in welltesting and by using Horner plot and Darcy low which is found by calculating slope in the plot, finally we can estimate permeability.

2.2.1.3 Core Permeability

Core analysis allows direct measurement of permeability under controlled laboratory conditions. For this reason, core-derived permeabilities are often considered to be the standard. This notion, however, can be misleading. Core permeability is an accurate representation of a particular core sample under specific laboratory conditions. Using this permeability value to represent reservoir formation permeability can be incorrect. As long as the measurements are consistent over a particular interval, however, the core permeability can be very useful in completion design. Specifically in choosing the phasing and vertical spacing of perforation.

2.3 Measuring Permeability in Lab by Analyzing Core

Core analysis as a direct measurement for finding the permeability, which is more accurate rather than the other methods, should consider some conditions and rules during the experimenting. The condition of experimenting should be same as in-situ condition of the plug in the reservoir, thus to find porosity and permeability, the condition of testing is explained as :

2.3.1 Porosity and grain density at ambient condition

Porosity and grain density of samples were determined by Ultraporosimeter 200A, (figure 2.5)using Helium injection. This apparatus uses Boyle`s law to determine pore or grain volume from the expansion of a known mass of Helium in to a calibrated sample holder.

Basic Boyle`s law: $\frac{P_1V_1}{T_1}=\frac{P_2V_2}{T_2}$

By calibrating with a series of known volume standards, the relationship between grain volume and the P1/P2 ratio can be as demonstrated in the following equation:

$$V_{grain}=(V_{matrix}+V_{refrence})-\frac{p1}{p2}(V_{refrence}) \qquad \text{Eq(4)}$$

Where:

V_{matrix} = Volume of sample holder P = Primary gas pressure

$V_{reference}$ =Volume of reference cell P = expanded gas pressure

Measured grain volumes can then be used in conjunction with bulk volume and weight measurements to calculate porosity and grain density.

2.3.2 Air permeability at ambient condition

The air permeability of samples is determined by Ultrapermeameter (Figure 2.5), which uses Darcy’s equation to calculate permeability from measured flow rate and upstream and downstream pressure. The equation is:

$$K_{air}=\frac{1000P_a\mu Q_a L}{A(P_1-P_2)(P_1+P_2)/2} \qquad \text{Eq(5)}$$

Where:

Kair = Air Permeability (milli Darcies) Q_a = Flow rate (cc/sec)

$(\frac{P1+P2}{2})$ = (Pm) Mean pressure across sample (atm) μ= Air viscosity

P_a =Atmospheric pressure(atm) L = Sample length (cm)

$P_1 - P_2$ = Pressure differential across sample (atm)

Figure 2.3: Ultraporosimeter 200A and Ultrapermeameter 200A

2.3.3 Archie classification and remarks

The Archie classification and some geology phenomena or remarks were determined for carbonate plugs by macroscopic visualization for all horizontal and vertical plug samples, the following pictures shows some geology phenomena or remarks. The following figure 2.6 is shown the classification of this study field rock which are cleared as anhydrite, crack, fracture,stylolite and vuggy.

Figure 2.4: Geology phenomena on core in research area

2.4 Measurement of absolute permeability with gas corrected for Klinkenberg effect

In 1942 Klinkenberg applied these principles to porous media and discovered permeability to a gas to be dependent upon molecular size, mean pressure and temperature. In particular he noted that the mean pressure at which the measurement was determined should qualify air permeability. The relationship developed by Klinkenberg on the basis of both theories and experimentation between permeability to gas and permeability to a liquid is: (Klinkenberg, 1941)

$$K = K_{\infty}(1 + \frac{b}{P_m}) \qquad \text{Eq(6)}$$

Where:

K = Permeability to a gas.

K_{∞} = Permeability at infinite mean pressure (the permeability of non- reactive liquid).

b = Klinkenberg factor for a given gas in a given porous media.

Pm = (P1 + P2)/2 Mean pressure of flow.

In the following figure 2.7 is shown, by plotting K from above eqation6 vs. 1/Pm , intercept is showing the klinkenberg permeability.

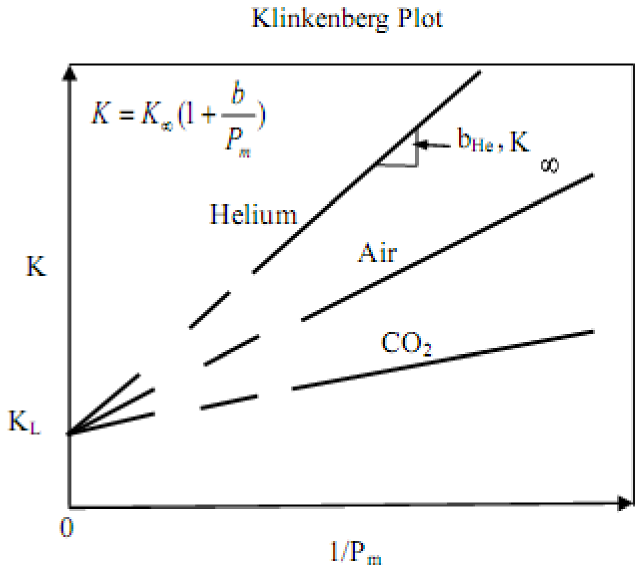


Figure 2.5: Klinkenberg Plot (Klinkenberg, 1941)

2.5 Core spectral gamma log

Core gamma spectrum was measured by “IFE SPECTRAL CORE GAMMA LOGGER” instrument (Figure 2.8).

This instrument measures the natural radioactivity presented in the cores. It can detect the total gross gamma counts and the radioactive isotope combinations of Potassium (wt %), Uranium (ppm) and Thorium (ppm) in the core.

This is achieved by using a large scintillation crystal detector, generous lead shielding for best possible signal/noise ratio obtaining accurate results also for small radiation changes.

Thus, porosity can find after doing this experiment by finding total gross gamma.

Figure 2.6: Spectral Core Gamma Logger (SCGL)

2.6 Empirical Approaches Used To Permeability Prediction

Empirical techniques use a calibration data set (e.g., data from core samples) and multiple regression analysis to determine the relationship between rock property variables and reservoir quality. The calibrated regression relationships are then used to predict reservoir quality in different settings but within the range of the variables comprising the calibration data set. Dutton and Diggs (1992) and Bloch (1991) describe the most frequently used application of this approach, in which relationships between measured porosity and permeability (usually ambient helium porosity and single-phase gas permeability), and textural and mineralogical variables (usually measured on thin sections), are investigated. Commonly used variables are grain size, sorting, matrix clay content, volume of individual cements, total cement volume, and point-counted interparticle porosity.

A variation on the empirical approach is described by Ehrlich et al. (1991). Using the observation that, even in a single formation, permeability commonly varies by several orders of magnitude, they conclude that the configuration, rather than the absolute value, of porosity is the control on permeability. To characterize the pore system configuration, Ehrlich et al. (1991) make measurements of pores in two dimensions (on polished thin sections) and combine these with pore-throat size distribution data (from mercury porosimetry) to develop a simple pore system model. For selected data sets, a good relationship between the simple pore system model and measured permeability has been established. It is unlikely, however, that we would be able to predict confidently the pore type and pore-throat size distribution parameters in an undrilled sandstone. In predicting permeability ahead of drilling, the criteria for success of any method must be that it establishes a quantitative link between measured permeability and another (or several other) rock parameter(s), and that those correlative parameters can themselves be predicted from a geological model. Many empirical approaches fail the second of these criteria.

2.6.1 Applications of the Empirical Approach

In areas with sufficient well data (either core analysis, log, or well test data) to define significant regional or field porosity–permeability and porosity–depth regressions, the empirical approach described above can often be successfully used to predict porosity and permeability in areas away from well control. This method is the one most commonly used in mature provinces, and gives good results provided there is not too much scatter in the data. However, the scatter is often such that the uncertainty in permeability prediction may cover several orders of magnitude. Some of this scatter may be due to textural variation, controlled in turn by sedimentary facies and lithology. If sedimentological information is available (from core logs or reservoir models), lithofacies can be taken into account by plotting the poroperm values for each lithofacies separately. Often the regression relationships for a given lithofacies will be better than those for the whole data set, since variations in grain size, clay content, and so forth will be reduced. The combination of empirical relationships for each facies with a sedimentological reservoir model may then produce a reasonable description of reservoir permeability variations. Further insight may be obtained through including mineralogical (e.g., from modal point counting), textural (e.g., grain size, sorting), and SCAL (e.g., critical pore-throat size, Kb) data in the regression analysis. In many cases, a few parameters will explain most of the variation in permeability (e.g., grain size, sorting, lithic content).

Wyllie&Rose, Timure, Tixier,Kozeny&Carmen and the other scientist who related the permeability and porosity together and proposed and modified empirical equation will be explained below as equations 7 till 21.

To predict the permeability in carbonate reservoir and find the best correlation, prediction in sandstone reservoir should be concerned

2.6.1.1 Methods to predict permeability for sand stone reservoir:

Reservoir characterization is a very important domain of petroleum engineering. An effective management strategy can be applied only after obtaining a detailed and close-to-reality ”image” of spatial distribution of rock properties. Among these, the most difficult to determine and predict is permeability. A great amount of work was done by several investigators in the attempt to grasp the complexity of permeability function into a model with general applicability. All these studies give a better understanding of the factors controlling permeability, but they also show that it is an illusion to look for a “universal” relation between permeability and other variables. (Archie, G.,E, 1942.)

The exits empirical studies give the guidelines for selecting the dependent variables which are to be used in the predictor development. A different predictive equation must be established for each new area or new field.

2.6.1.2 Empirical Equations:

Empirical models are based on the correlation between permeability, porosity, and irreducible water saturation are listed as it is written below.

Kozeny, 1927 .

The first equation for relationship between measurable rock properties with permeability was proposed in 1927 by Kozeny:

$$K = A\frac{\emptyset}{Sp^2} \qquad \text{Eq (7)}$$

or

$$\mathrm{K} = A\frac{\emptyset}{\mathrm{Sp}^2} \qquad \text{Eq (8)}$$

and modified by Carman:

$$\mathrm{K} = \mathrm{A}\frac{\emptyset^3}{\mathrm{So}\,(1-\emptyset)^2} \qquad \text{Eq (9)}$$

Where:

A -empirical constant, known as the Kozeny constant

S -surface area per unit bulk volume

S_p -surface area per unit volume of pore space

S_o -surface area per unit volume of solid material.

The $\frac{\emptyset^3}{(1-\emptyset)^2}$ is the relation of permeability to average grain diameter.

Wyllie and Rose-1950 :

A general empirical relationship proposed by Wyllie and Rose (1950) relates permeability (K), porosity (Ø), and irreducible water saturation (Swi) as follows:

$$\mathrm{K} = \mathrm{a}\frac{\emptyset^{\mathrm{b}}}{{\mathrm{S}_{\mathrm{wi}}}^{\mathrm{c}}} \qquad \text{Eq (10)}$$

Where *a*, *b*, and *c* are statistically determined model parameters.

$$\mathrm{K}^{1/2} = 100\frac{\emptyset^{2.25}}{\mathrm{Swi}} \qquad \text{Eq (11)}$$

Tixier-1949

By using relationships between resistivity and saturation of water, capillary pressure and water saturation, and permeability and capillary pressure, He found a method to determine permeability from gradients of resistivity.

$$K = C(a\frac{2.3}{\rho w - \rho o})^2 \qquad \text{Eq (12)}$$

$$a = \frac{\Delta R}{\Delta D}\frac{1}{Ro} \qquad \text{Eq (13)}$$

Where:

C is a constant, normally about 20,

ΔR is the change in resistivity (ohm-m), ΔD is the change in depth(ft), corresponding to ΔR

ρ_w is formation water density (g/cm^3),

ρ_o is hydrocarbon density (g/cm^3).

Equation 4 and 5 can be rewritten as:

$$(\frac{K}{20})^{0.5} = \frac{2.3}{Ro\,(dw - do\,)}\frac{\Delta R}{\Delta D} \qquad \text{Eq (14)}$$

Tixier assumed that saturation component(n) is 2.0, and in any water saturation, capillary pressure has relation with permeability as : $Pc=f/K^{0.5}$

Tixier by following work of Wyllie and Rose, developed a model which is used more often than equation 3:

$$K = 62.5\frac{\emptyset^6}{{S_{wi}}^2} \qquad \text{Eq (15)}$$

Sheffield , 1956 .

Based on Kozeny's equation, Sheffield proposed the following correlation for permeability:

$$K = \frac{1}{2F}(\frac{\emptyset}{1-\emptyset})^2\frac{1}{Swi^2} \qquad \text{Eq (16)}$$

This model is valid for Clean Sand

Pirson , 1963 .

The permeability formula proposed by Pirson is:

$$K = \left(\frac{850000}{API} - 3.5D\right)(\frac{Rw^2}{FR_o R_{ti}}) \qquad \text{Eq (17)}$$

Timure,1968.

By using Wyllie and Rose model with Core Data:

$$K_1^{0.5} = 0.1\frac{\emptyset^{2.25}}{S_{wi}} \qquad \text{Eq (18)}$$

By using well log data :

$$K_2 = 8.58\frac{\emptyset^{4.4}}{{S_{wi}}^2} \qquad \text{Eq (19)}$$

Cotes,1981

Cotes and Denoo proposed following equation:

$$K^{1/2} = 100\frac{\emptyset^2(1-Swirr)}{Swirr} \qquad \text{Eq (20)}$$

Morris&Beggs, 1985

$$K = 250\frac{\emptyset^3}{{S_{wi}}^2} \qquad \text{Eq (21)}$$

Referenced all equation to (Balan, B et al,1995).

2.7 Porosity-Permeability Relationship in Carbonate Reservoir

Figure 2.9 shows a plot of permeability versus porosity data obtained from a large number of samples of a sandstone formation. Even though this formation is generally considered very uniform and homogeneous, there is not a specifically defined trendline between permeability and porosity values. In this case, the relationship between permeability and porosity is qualitative and is not directly or indirectly quantitative in any way. It is possible to have very high porosity without having any permeability at all, as in the case of pumice stone (where the effective porosity is nearly zero), clays, and shales. The reverse of high permeability with a low porosity might also be true, such as in micro-fractured carbonates. In spite of this fundamental lack of correspondence between these two properties, there often can be found a very useful correlation between them within one formation as it is shown in figure 2.10 (Tiab et al, 2004).

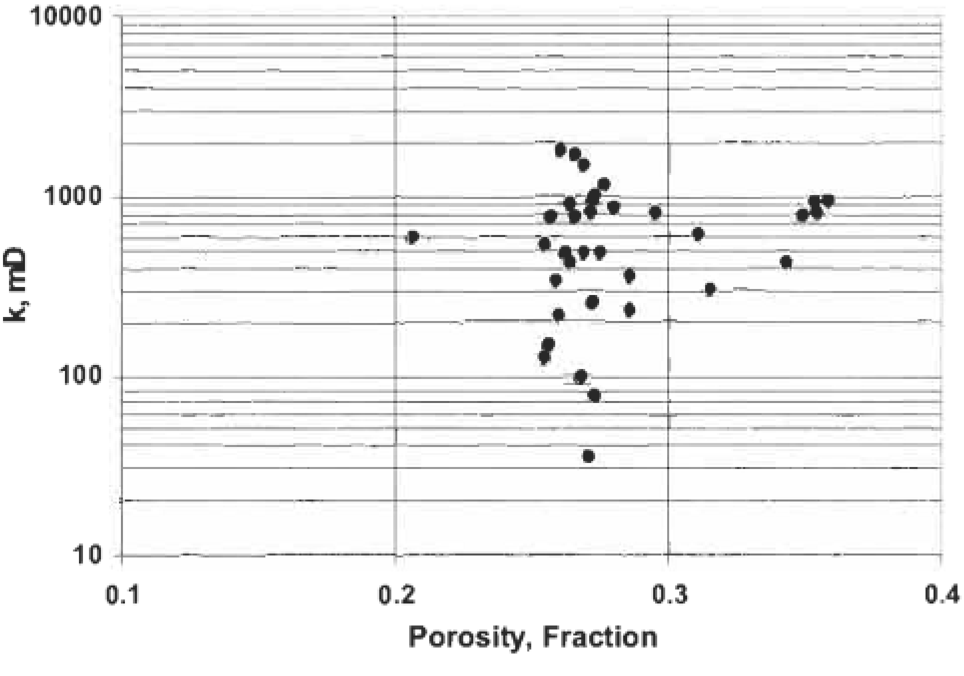


Figure 2.7: Permeability and Porosity Relationship In Sandstone Reservoir

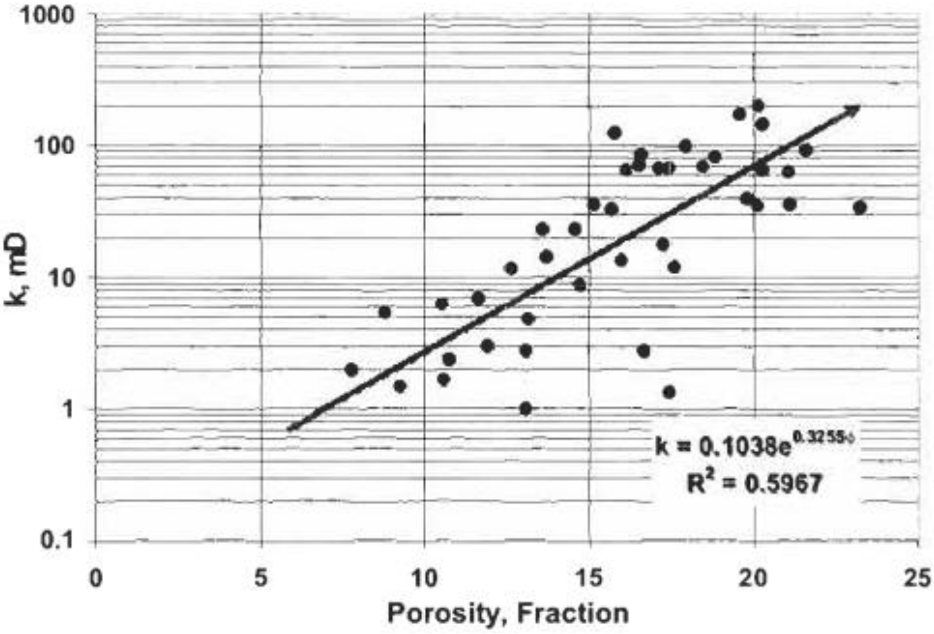


Figure 2.8: Permeability-Porosity Relationship

Figure 2.11 shows typical permeability and porosity trends for various rock types. Such a relationship is very useful in the understanding of fluid flow through porous media. Many correlations relating permeability, porosity, pore size, specific surface area, irreducible fluid saturation, and other variables have been made (Tiab et al,2004)

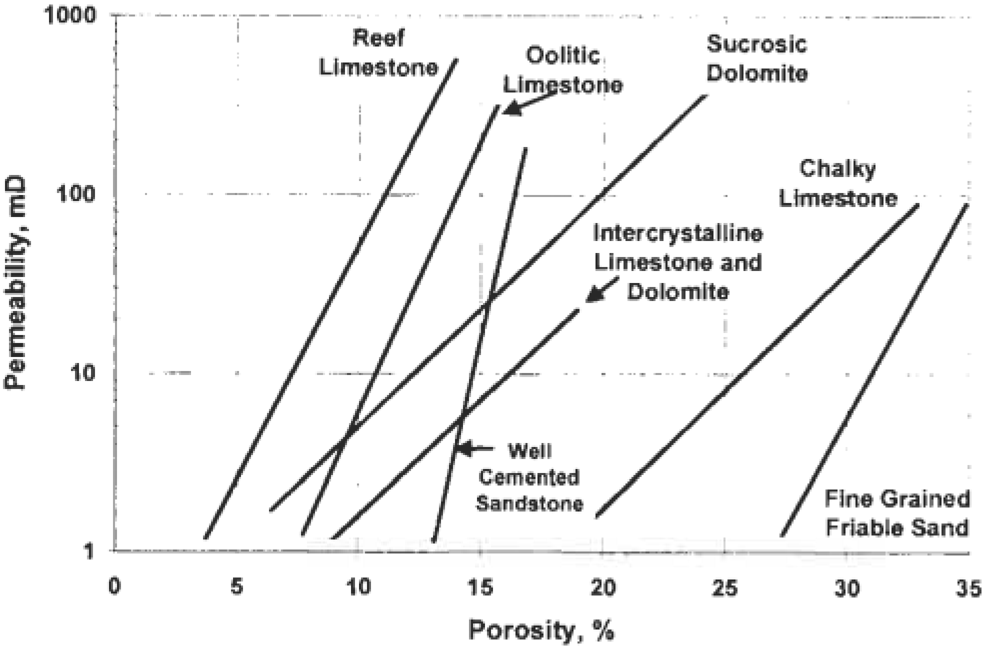


Figure 2.10: Typical permeability-porosity relationship for various rock types (courtesy of Core Laboratories).(Tiab et al, 2004)

2.7.1 Empirical Equations for predicting Permeability in Carbonate Reservoir

A correlation between porosity and permeability was established, which is of vital importance in carbonate reservoir rock characterization.

On considering two additional variables (irreducible fluids saturation and specific surface area, which is a measure of degree of fracturing), very good correlation was obtained between porosity and permeability. Without considering these two variables, the coefficient of correlation is commonly very low. . (Chillingar et al 2008)

1-Vuktyl'skiy Gas-Condensate Field, Russia. (Chillingar et al 2008)

$\log k = 0.9532 – 2.7880 \text{ x } 10^{-2}$ Swr – 5.5597 x 10-4 S_s+ $1.3309 \text{ x } 10^{-1}\emptyset$ +
$1.1707 \text{ x } 10^{-5} S_{wr} * S_s$ Eq (22)

Lithology : Dolomites to true Limestone

2- Central Asia.(Chillingar et al 2008)

$\log k = 3.8690 – 1.0536 \text{ x } 10^{-1} S_{wr} – 4.1979 \text{ x } 10^{-4} S_s + 6.5363 \text{ x } 10^{-6} S_{wr} * S_s + 2.8324$
$S_{wr} *\emptyset$ Eq (23)

Lithology : Both Dolomite and Limestone

3- Kuybyshev, Along Volga Region. Russia.(Chillingar et al 2008)

$\log k = 2.1085 – 5.0777$ x 10-2 S_{wr} – 4.3785x 10-4 S_s+ $7.9959 \text{ x } 10^{-2}\emptyset$ + 7.6326 x 10-
6 $S_{wr} * S_s$ Eq (24)

Lithology : Mainly Limestone

4- Orenburg Field, Russia.(Chillingar et al 2008)

$\log k = 3.4351 – 2.0442 \text{ x } 10^{-1} S_{wr} + 9.5086 \text{ x } 10^{-6} S_{wr}$ * ss + 8.0217 x 10-3 $S_{wr}*\emptyset$ -
2.3892 x 10-5 $S_s *\emptyset$ Eq (25)

CHAPTER 3

RESEARCH METHODOLOGY

The aim of this chapter is to provide a detailed study on the methodology of the research work carried out in order to achieve the objectives mentioned in Chapter 1. The method that is proposed by Willey and Rose for estimation of horizontal permeability of Sandstone reservoir is acknowledge and regarded as standard equation for permeability estimation

$$K = a\frac{\emptyset^{b}}{{S_{wi}}^{c}} \qquad \text{Eq (10)}$$

From the above equation is cleared that permeability has direct relation with the porosity of the formation and inverse relation with the irreducible water saturation.

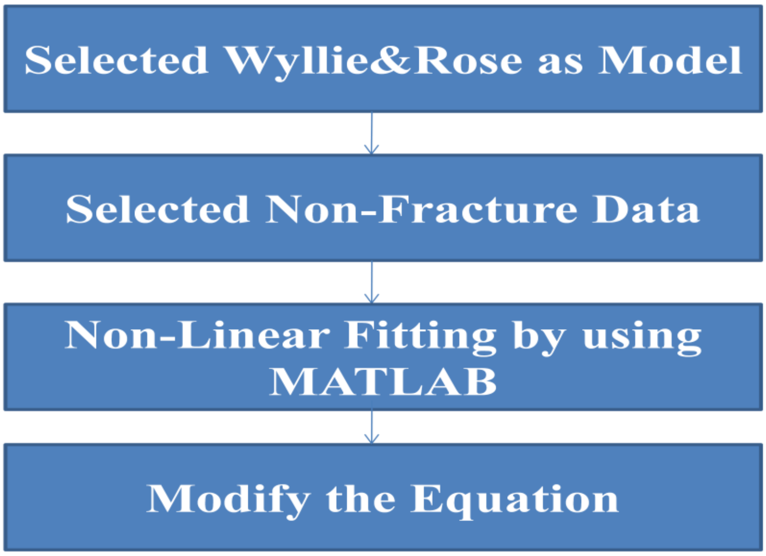
For calculating the coefficients of Wyllie and Rose (1950), both Sarvak and Fahliyan formations are considered. All the data has been provided from a research institute. In the laboratory, porosity was measured and calculated by a Porosimeter apparatus which uses helium for injecting, and by Boyle's law. Water saturation is obtained by Archie's equation which uses resistivity factors and saturation exponents. All resistivity's and saturation exponents were measured in a laboratory. For permeability measurements, air permeability was measured at the beginning and Klinkenberg corrections were done for each of the samples.

Two hundred and fifty two plug samples were selected. Furthermore, all information was attained by CCAL (Conventional Core Analysis) experiments in the laboratory. Fractures and micro-fractures were omitted from our data. According to carbonated reservoirs, some plugs will be out because of strong heterogeneity and high fractures in the cores. Finally, fifty two non-fracture core plugs with Klinkenberg permeability ranging between 1 to 100 mD were selected. Therefore, using Klinkenberg permeability, laboratory porosity and water saturation while taking into account Eq.3 , my equation was obtained.

The correct estimation of above coefficients is carried out by generating this model in MATLAB.

The set of steps that are used in MATLAB includes

- Input porosity Data
- Input Irreducible Water Saturation Data
- Fit the Data with Klinkenberg permeability by using non-linear fitting to find coefficient



For limited given SCAL data as it is written in table 3.1 of, relative permeability of oil and water, irreducible water saturation was obtained, and extrapolation approach is followed through plotting S_{wirr} against Depth, in order to find irreducible water saturation at desired depth. As its shown in figure 3.1 for one sample by plotting K_{ro} Vs K_{rw} Vs Water Saturation , S_{wir} is findable.

Table 3.1: SCAL Data for Relative Permeability for one Sample

WATER SATURATION % PORE SPACE	Krw	Kro	Krw/Kro
100.00	**1.000**	**0.000**	**-**
84.57	**0.080**	**0.119**	**0.669**
82.95	**0.073**	**0.137**	**0.532**
81.12	**0.065**	**0.156**	**0.420**
79.03	**0.058**	**0.177**	**0.329**
77.17	**0.052**	**0.194**	**0.268**
74.85	**0.046**	**0.216**	**0.211**
72.74	**0.040**	**0.236**	**0.172**
70.35	**0.035**	**0.257**	**0.137**
68.33	**0.031**	**0.275**	**0.113**
66.44	**0.028**	**0.292**	**0.095**
64.67	**0.025**	**0.307**	**0.081**
62.94	**0.022**	**0.323**	**0.069**
61.25	**0.020**	**0.338**	**0.059**
59.57	**0.018**	**0.353**	**0.051**
57.95	**0.016**	**0.367**	**0.044**
56.29	**0.014**	**0.382**	**0.038**
54.38	**0.013**	**0.399**	**0.032**
52.32	**0.011**	**0.418**	**0.026**
50.22	**0.009**	**0.437**	**0.021**
47.81	**0.008**	**0.460**	**0.017**
45.40	**0.006**	**0.483**	**0.013**
42.94	**0.005**	**0.507**	**0.010**
40.43	**0.004**	**0.532**	**0.007**
37.56	**0.003**	**0.561**	**0.005**
34.39	**0.002**	**0.595**	**0.003**
31.01	**0.001**	**0.631**	**0.002**
25.76	**0.000**	**0.684**	**0.000**

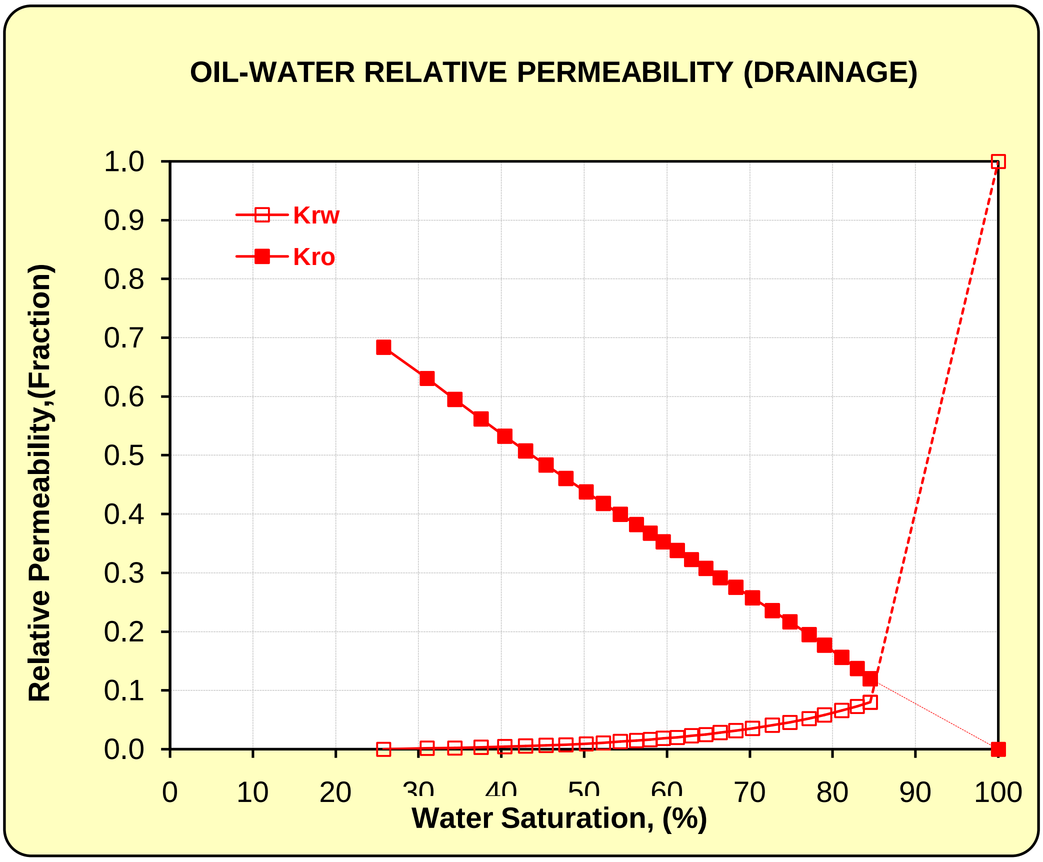


Figure 3.1: Relative Permeability of Oil and Water Plot to find S_{wir}

CHAPTER 4

RESULTS AND DISCUSSIONS

The parameters of Wyllie and Rose’s equation (1950) a, b, and c were calibrated from the fit core measurement. The model for non-fracture data for South West of Iran is as follows:

$$\mathrm{K} = 1.074 * \frac{\emptyset^{\,3.243}}{\mathrm{Swir}^{\,0.494}} \qquad \text{Eq (26)}$$

Where porosity and water saturation are in fraction and permeability is in Darcy.

Comparison between calculated k in this equation and measured k by Klinkenberg measurement in the laboratory is shown in Fig.4.1. According to this figure the coefficients a, b, and c are generalized. Deviation of the line which is related to calculated permeability from measured permeability is acceptable.

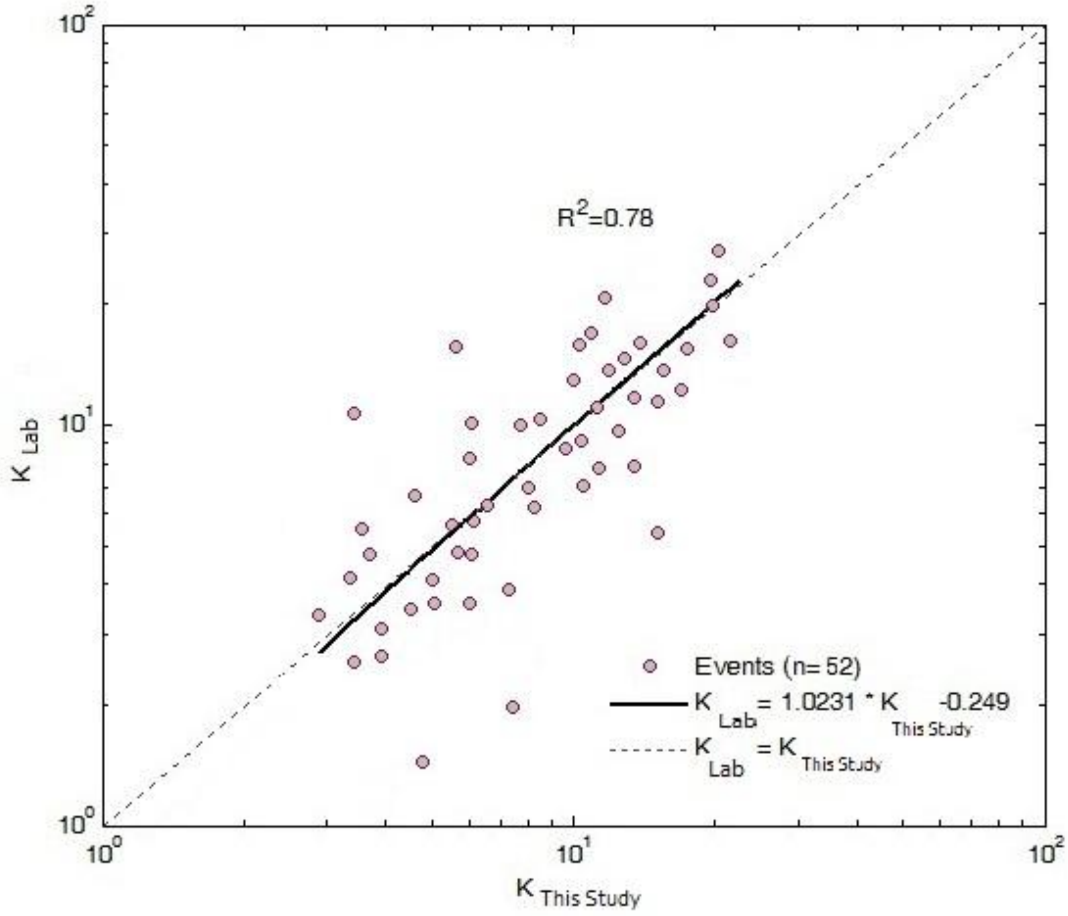


Figure 4.1: $K_{\text{this study}}$ Vs K_{Lab}

4.1 Process of Finding Wyllie &Rose Coefficients

By using Non-Linear fitting in MATLAB software as it is shown below, the code of wanted function

Function f = myfun(x,M)

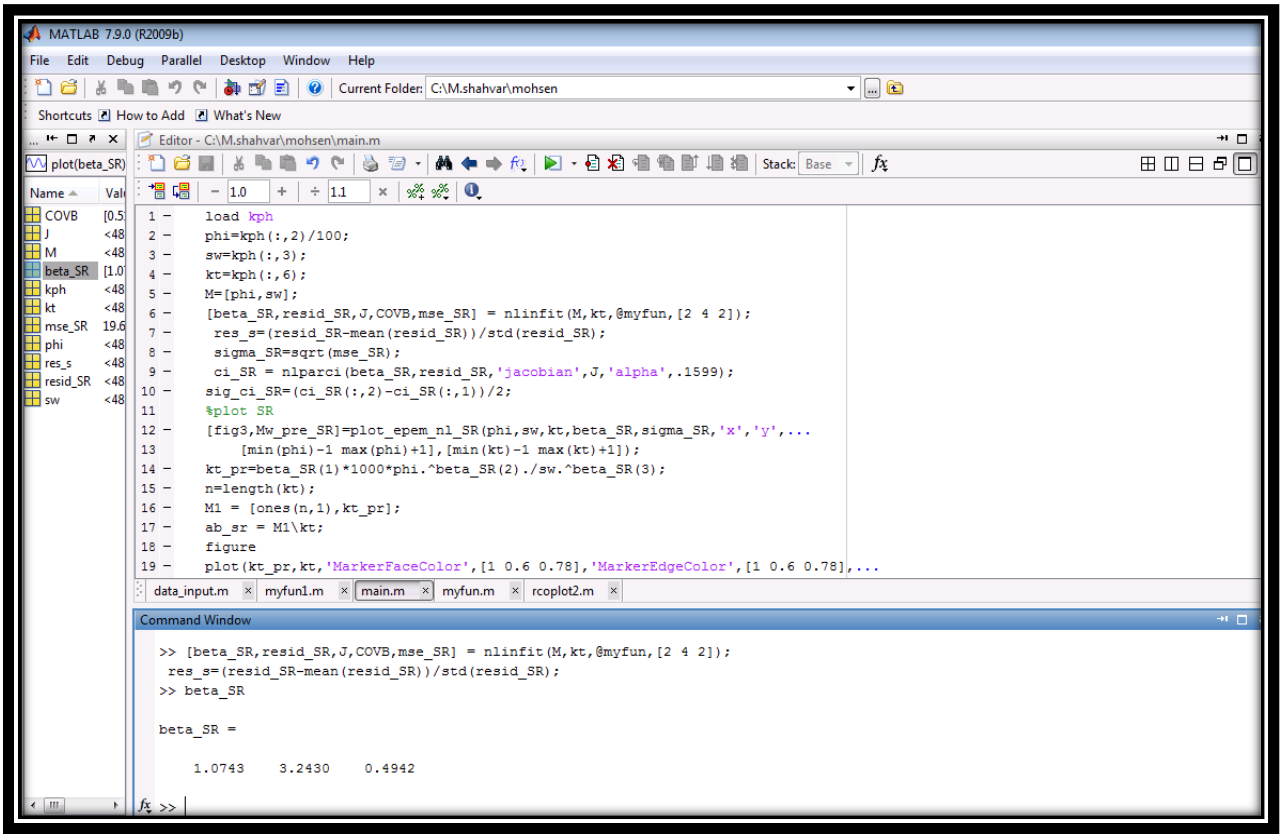
Phi=M(:,1);

Sw=M(:,2);

f = (1000*x(1)*phi.^x(2))./(sw.^x(3));

Where : x(1), x(2) and x(3) are Wyllie&Rose coefficients, a,b and c respectively.

As it is shown in figure 4.2 , after proceeding the written function MATLAB will find the best fit for all given data and in the command window as it is cleared, will reveal the x(1),x(2) and x(3).



```
load kph
phi=kph(:,2)/100;
sw=kph(:,3);
kt=kph(:,6);
M=[phi,sw];
[beta_SR,resid_SR,J,COVB,mse_SR] = nlinfit(M,kt,@myfun,[2 4 2]);
 res_s=(resid_SR-mean(resid_SR))/std(resid_SR);
 sigma_SR=sqrt(mse_SR);
 ci_SR = nlparci(beta_SR,resid_SR,'jacobian',J,'alpha',.1599);
sig_ci_SR=(ci_SR(:,2)-ci_SR(:,1))/2;
%plot SR
[fig3,Mw_pre_SR]=plot_epem_nl_SR(phi,sw,kt,beta_SR,sigma_SR,'x','y',...
    [min(phi)-1 max(phi)+1],[min(kt)-1 max(kt)+1]);
kt_pr=beta_SR(1)*1000*phi.^beta_SR(2)./sw.^beta_SR(3);
n=length(kt);
M1 = [ones(n,1),kt_pr];
ab_sr = M1\kt;
figure
plot(kt_pr,kt,'MarkerFaceColor',[1 0.6 0.78],'MarkerEdgeColor',[1 0.6 0.78],...
```

```
>> [beta_SR,resid_SR,J,COVB,mse_SR] = nlinfit(M,kt,@myfun,[2 4 2]);
 res_s=(resid_SR-mean(resid_SR))/std(resid_SR);
>> beta_SR

beta_SR =

    1.0743    3.2430    0.4942

>>
```

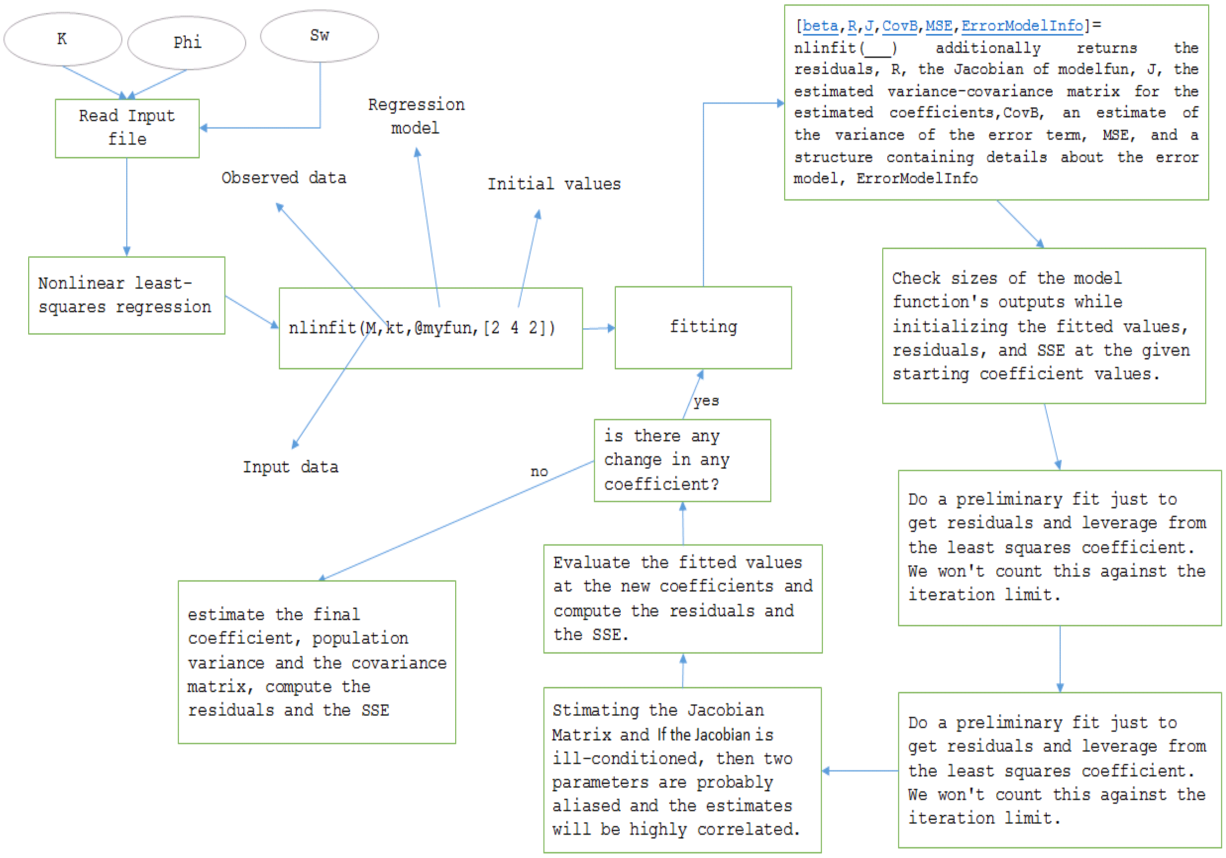


Figure 4.2: MATLAB Process To Find The Coefficients of Modified Equation

4.2 Relationship between K_c and Ø

Poroperm trends for different lithologies can be plotted together, and form a map of Poroperm relationships, as shown and discussed in chapter2 in Fig. 2.10.

The range of calculated permeability versus porosity as shown in Fig. 4.3 can confirm the geology features of our study area. After checking the whole geology features of plugs selected for this work, it was determined the important advantage of equation (26) is that the equation is independent of geology features. It was observed that this equation covers most carbonate rock types such as: Vugs, Stylolite, Solution Steam, Compact, Chalky, and Granular Matrix, which are all related to south west reservoir of Iran and discussed in Archie classification in chapter2. In Fig. 4.2 the relationship between calculated permeability versus laboratory porosity is sketched.

Distribution between calculated permeability and porosity approximately shows a nonlinear relation.

Where porosity is in percentage and permeability is expressed in mD. According to the typical permeability-porosity relationship shown in Fig. 2.9, the range of kc Vs Ø in this figure is related to intercrystalline limestone, dolomite, and chalky limestone, which confirms our conclusion for covering geology features using equation(26).

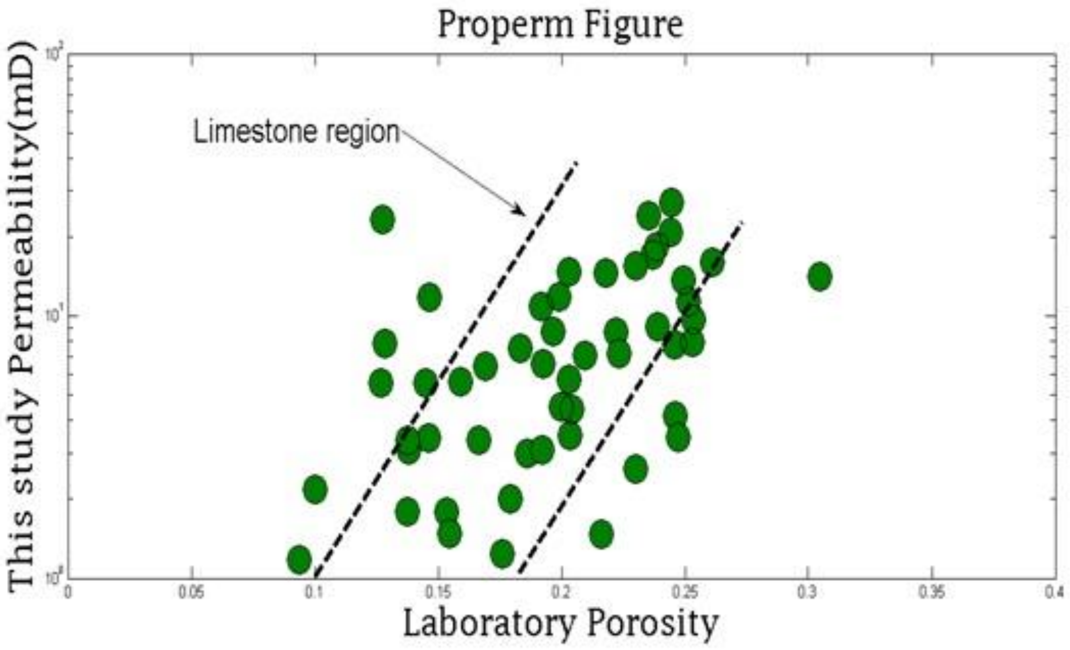


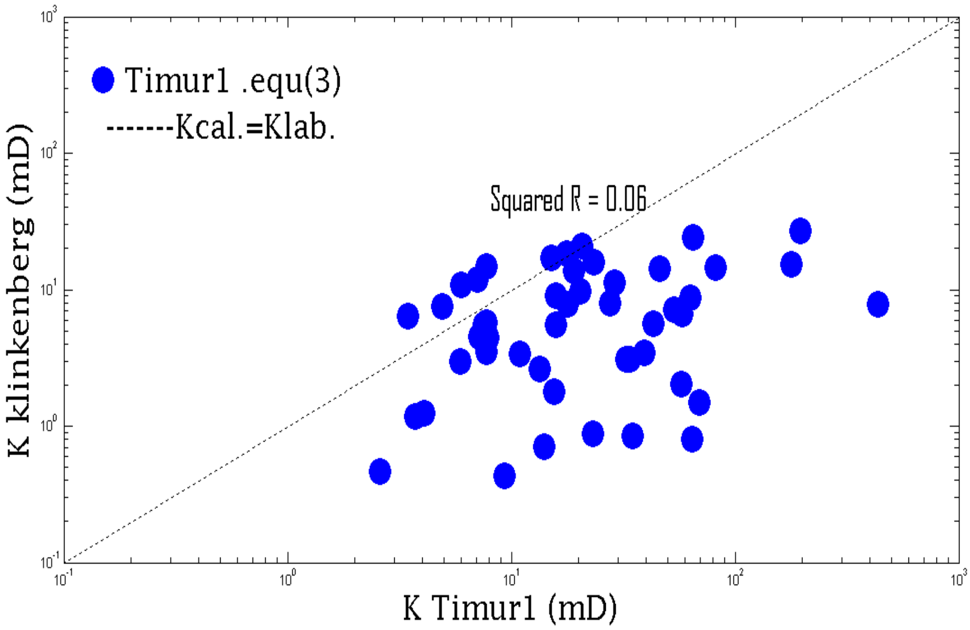
Figure 4.3: Geology Feature of Calculated Permeability

4.3 Comparison of modified equation with other empirical equations:

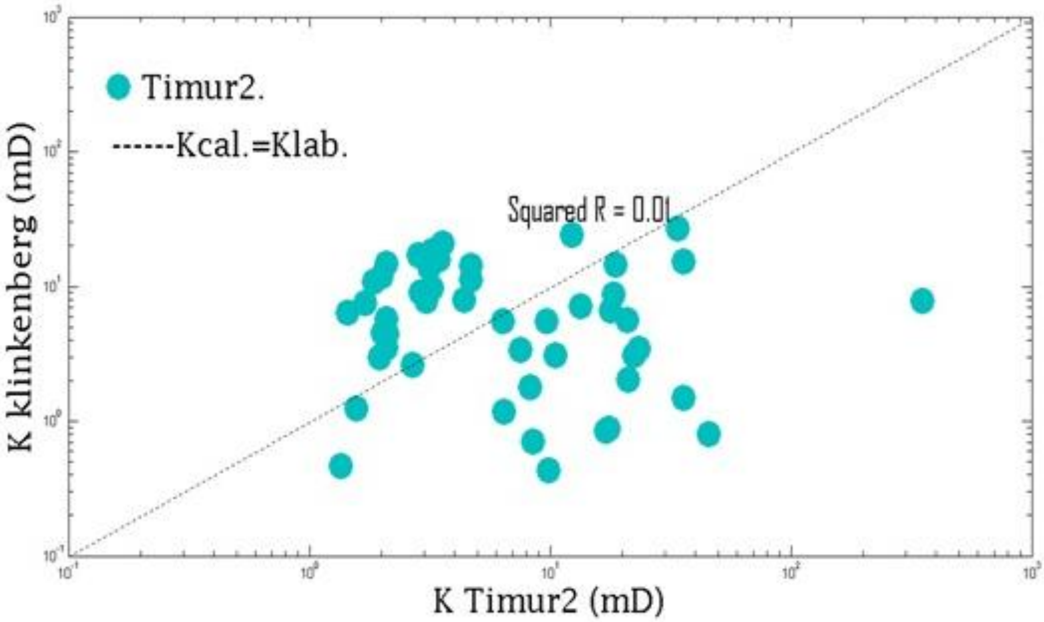
As it is clear in all following graphs, calculated permeability from all empirical equations which are following same model, plotted versus klinkenberg permeability, other equation like Tixier, Timur, as R^2 is showing, don’t have good distribution compare to modified equation (26).

Which are showing R^2, 0.06, 0.01 and 0.26 for Timur1, Timur2 and Tixier respectively.

(A)


Timur1 .equ(3)
-------Kcal.=Klab.
Squared R = 0.06
K klinkenberg (mD)
K Timur1 (mD)
10^{3}
10^{2}
10^{1}
10^{0}
10^{-1}
10^{-1}
10^{0}
10^{1}
10^{2}
10^{3}

(B)


Timur2.
------Kcal.=Klab.
Squared R = 0.01
K klinkenberg (mD)
K Timur2 (mD)
10^{3}
10^{2}
10^{1}
10^{0}
10^{-1}
10^{-1}
10^{0}
10^{1}
10^{2}
10^{3}

(C)

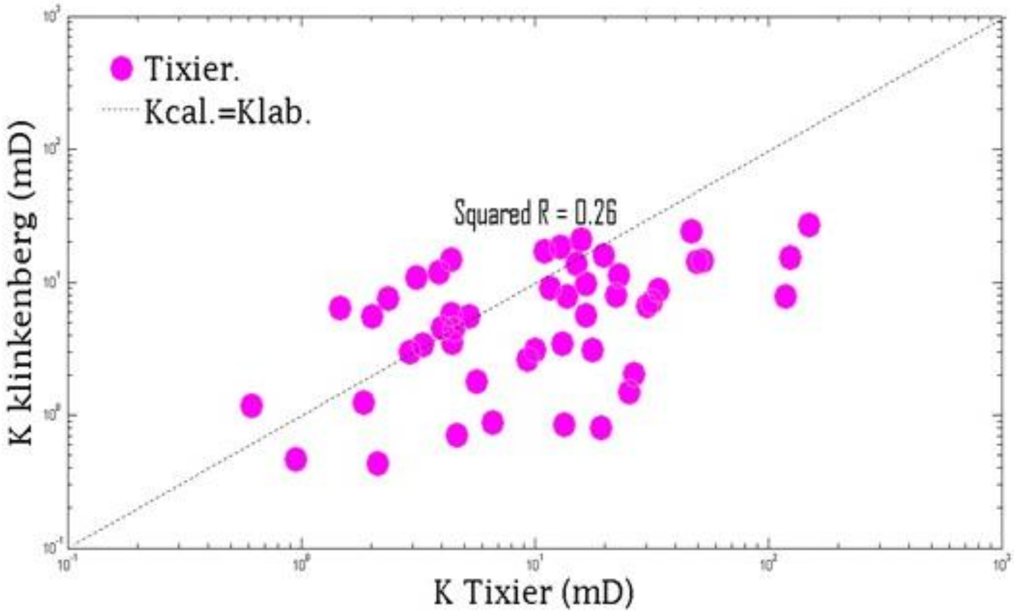
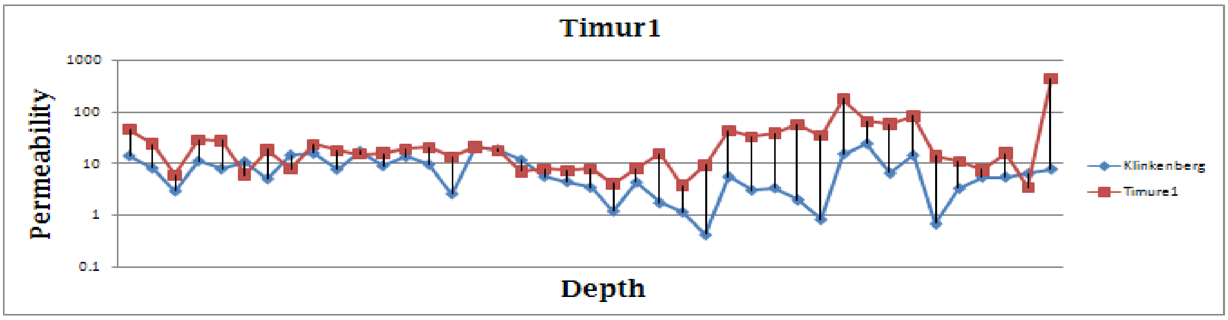
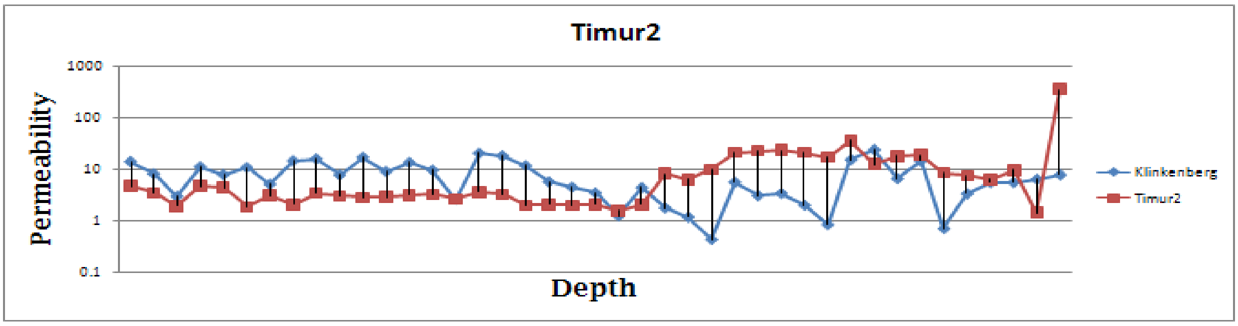
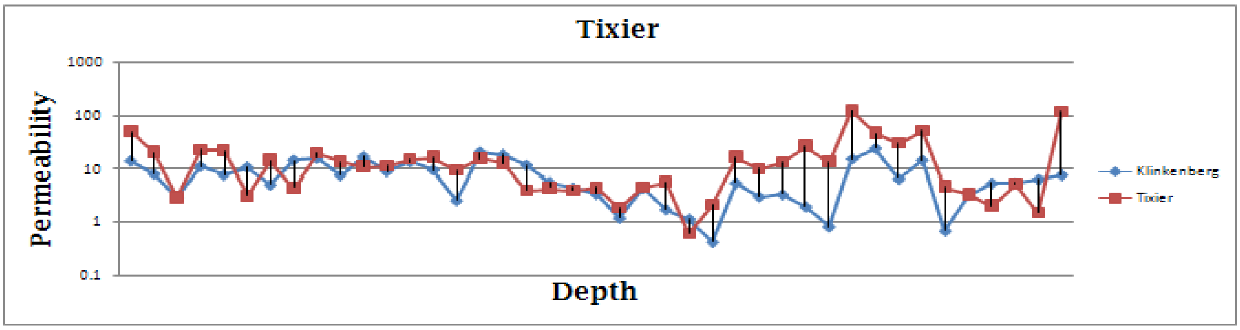


Figure 4.4: Measured permeability Vs. Calculated permeability for each empirical equation: A) Timur1 formula with K Lab. B) Timur2 formula against K Lab. C) Tixier formula against K Lab. (All permeabilities expressed in mD)







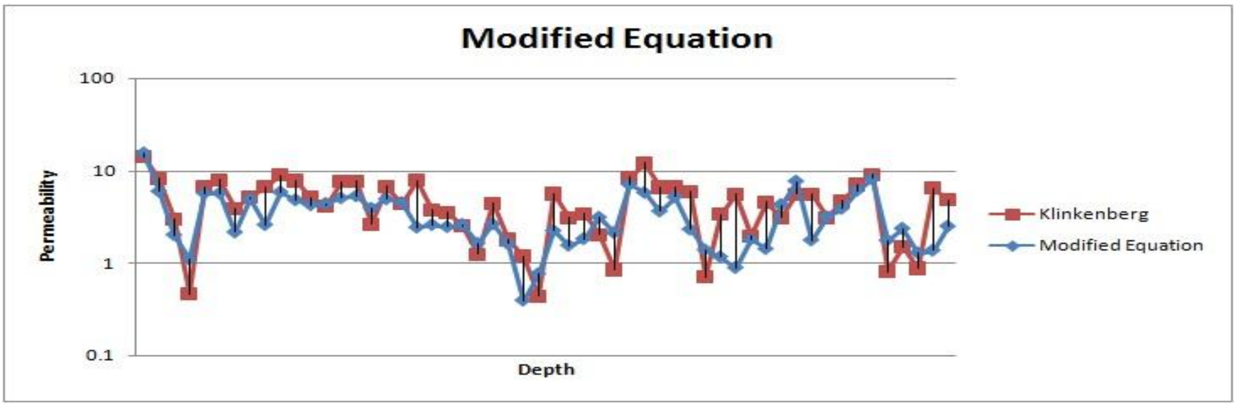


Figure 4.5: Comparison between modified equation permeability and other empirical models versus Depth.

CHAPTER 5

CONCLUSION

Applying this study's equation, I have evaluated a new permeability estimation equation from porosity and irreducible water saturation. Discrepancy of the permeability estimation between the models is expected due to their dissimilar mechanisms. The regular Tixier and Timur1 models were proposed from well log data. While Timur2 like this study formula were obtained from core samples. The rock permeability, porosity, and irreducible water saturation is first determined from core samples by modifying permeability using Klinkenberg correction. In order to obtain the tuning parameters of general, Wyllie and Rose equation are used by deriving nonlinear models for curve fitting once the optimal equation is obtained between porosity and measured permeability estimation, proving the geology features of our study area. We applied this method to several sets of core samples from an Iranian Carbonate and compared them with existing empirical permeability estimation models. It's found that all presented models underestimated the permeability of this study numerical model. For all the data of core samples, Tixier's prediction was better than others, while my correlation almost overestimated the permeability, whereas both Timur underestimated them. In addition, the proposed this study equation has the best distribution against the others, and has the best match in lithology plot to existing models. According to the comparison between measured and calculated permeability, this study equation consistently produced correlation superior to the three existing models they were compared against.

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