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Graduation Project about:

SCAL data, computer program creation for sandstone reservoir relative permeability normalization

تصميم برنامج لعمل *Normalization* للنفاذيه النسبيه لمكامن الحجر الرملي

Submitted to College of Petroleum Engineering & Technology in Sudan University partial fulfillment for one of requirement to take the degree of B.Sc. In Petroleum Engineering

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هذا المشروع مقدم إلى كلية هندسة وتكنولوجيا النفط ــجامعة السودان للعلوم والتكنولوجيا كإنجاز جزئي لأحد المتطلبات الأساسية لنيل درجة البكالوريوس مرتبة الشرف في هندسة النفط.

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قال تعالى:

(وَقُلِ اعْمَلُوا فَسَيَرَى اللَّهُ عَمَلَكُمْ وَرَسُولُهُ وَالْمُؤْمِنُونَ ۖ وَسَتُرَدُّونَ إِلَىٰ عَالِمِ الْغَيْبِ وَالشَّهَادَةِ فَيُنَبِّئُكُمْ بِمَا كُنْتُمْ تَعْمَلُونَ).

سورة التوبه

الايه 105

To my dear parents

I can't thank you enough for all the support and sacrifices you have done to me when I needed them. I'm grateful to have both of you by my side; it gave me strength and guidance. I wouldn't have become the man I am today if it wasn't for the both of you. Thank you for believing in me, I promise to never let you down

I love you with all my heart and I'm proud to be yours

To our brothers and sisters

To our friends

To our teachers

Thank

You

all

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Abstract

Special core analysis data (SCAL) is one of the important data which obtained by applying tests on samples which extracted from oil reservoirs to determine the reservoir formations properties such as (overburden pressure, capillary pressure, wettability, relative permeability and surface tension).

In our project studied the relative permeability and it's importance in reservoir calculation such as fluids movement and estimating the residual oil / gas saturation.

After got the relative permeability raw data some mathematical equations are applied to smooth and average the relative permeability data to be able to use in simulator.

Observed that the ordinary method which was used to prepare the relative permeability data to be able to use in simulator , it's consumed a lot of time and effort ,for this reason create a computer program to prepare the relative permeability data in a few minutes comparing with the ordinary method (Excel program).

التجريد

تعتبر بيانات اللباب الصخري من أهم البيانات المأخوذة منالاختبارات التي أجريت على العينات المستخرجة من المكامن النفطية لمعرفة خواص الطبقات المكمنية وهي: (التبلل, الضغط الشعيري,النفاذية النسبية , التوتر السطحي و ضغط التطبق).

في هذا المشروع تم دراسة النفاذيه النسبيه وأهميتها في الحسابات المكمنيه وفي تحرك السوائل وتقدير المتبقي من الزيت والغاز إن وجد, وكيفية طرق قياس النفاذيه, وبعد الحصول على النفاذيه النسبيه يتم اجراء بعض المعادلات الرياضيه لإزالة النقاط الشاذة وعمل المتوسط للنفاذية النسبية حتنتصبح جاهزه للاستخدام في برامج تمثيل المكامن.

تمت ملاحظة أن الطرق الاعتياديه المستخدمه لتجهيز بيانات النفاذيه النسبيه لتصبح جاهزه لاستخدامها في برامج تمثيل المكامن أنها تستغرق الوقت والجهد الكثير , فقمنا بعمل برنامج حاسب ألي يقوم بتجهيز بيانات النفاذية النسبيه باستخدام لغه (**Visual studio**)حيث ان البرنامج يعمل علىتقليل الوقت والجهد المستغرق مقارنة بالعمليات الاعتيادية مثل برنامج الإكسل(**Excel program**).

NOMENCLATURE

g : Gravity acceleration.

$\bar{g}$: Gravitational vector.

H : Thickness (ft).

K : Air Permeability (mD).

$\bar{\bar{k}}$: Permeability tensor.

k_h : Horizontal Permeability.

k_v : Vertical Permeability.

k_o : Oil Permeability.

k_w : Water Permeability.

k_g : Gas Permeability.

k_{ro} : Oil Relative Permeability.

k_{rw} : Water Relative Permeability.

k_{rg} : Gas Relative Permeability.

L : Length (ft).

P : Pressure (psi).

P_c : Capillary Pressure.

p_m : Mean pressure

∇P : Pressure Gradient ($\frac{psi}{ft}$).

∇p : Deferential Pressure (psi).

Q : Volumetric Flow (ft^3).

S_o^* : Normalize Oil Saturation.

S_w^* : Normalize Water Saturation.

S_g^* : Normalize Gas Saturation.

λ_t : Total system mobility.

$\bar{u}$: Superficial velocity ($\frac{ft}{s}$).

μ : Fluid Viscosity ($C.P$).

ρ : Density ($\frac{lb}{ft^3}$)

$\emptyset$: Porosity.

$\emptyset_a$: Absolute porosity.

θ : Contact angle.

ABBREVIATION

ATM : **Atmosphere.**

CCAL : **Conventional Core Analysis Log.**

Cgs : **Centimeter-gram-second System.**

DST : **Drill Stem Test.**

IFT : **Interfacial Surface Tension**

RFT : **Repeated Formation Tester.**

PVT : **Pressure Volume Temperature.**

Qc : **quality control.**

S : **Skin Factor.**

SCAL : **Special Core Analysis Log.**

SI : **International system.**

S_{nw} : **Saturation of Non-wetting Phase.**

S_{oc} : **Critical Oil Saturation.**

SRTT : **Static reservoir rock type.**

S_w : **Water Saturation.**

S_{wir} : **Irreducible Water Saturation.**

WOC : **Water Oil Contact.**

Chapter One:

Introduction

1.1. Introduction:

A petroleum reservoir is an underground porous medium in which oil or gas or both are trapped structurally or/and stratigraphically. Fluid flow in such a porous medium is very complex phenomena. To understand and predict the volumetric behavior of oil and gas reservoirs as a function of pressure, knowledge of the physical properties of reservoir fluids must be gained. These fluid properties are usually determined by laboratory experiments performed on samples of actual reservoir fluids. In the absence of experimentally measured properties, it is necessary for the petroleum engineer to determine the properties from empirically derived correlations. The material of which a petroleum reservoir rock may be composed can range from very loose and unconsolidated sand to a very hard and dense sandstone, limestone, or dolomite. The grains may be bonded together with a number of materials, the most common of which are silica, calcite, or clay. Knowledge of the physical properties of the rock and the existing interaction between the hydrocarbon system and the formation is essential in understanding and evaluating the performance of a given reservoir. Rock properties are determined by performing laboratory analyses on cores from the reservoir to be evaluated. The cores are removed from the reservoir environment, with subsequent changes in the core bulk volume, pore volume, reservoir fluid saturations and sometimes, formation wettability.

The effect of these changes on rock properties may range from negligible to substantial, depending on characteristics of the formation and property of interest, and should be evaluated in the testing program. There are basically two main categories of core analysis tests that are performed on core samples regarding physical properties of reservoir rocks. Two types of tests are:

1.1.1. Routine core analysis tests These are:

1. Porosity ($\emptyset$) .

2. Permeability (K).

3. Saturation (S) .

1.1.2. Special tests:

1. Overburden pressure (P_{ov}).
2. Capillary pressure (P_c).
3. Relative permeability (k_r).
4. Wettability.
5. Surface and interfacial tension .   .

In our research, we will focus on special core analysis (SCAL), to build a computer program by using visual studio to prepare SCAL data in simulator format to be ready use in simulator.

Special core analysis (SCAL) is one of the main sources of data available to guide the reservoir engineer in assessing the economic potential of a hydrocarbon accumulation.

The data sources can be divided into field and laboratory measurements as shown in Figure (1.1.) Laboratory data are used to support field measurements which can be subject to certain limitations, EX:

I.   Fluid saturations may be uncertain where actual formation brine composition and resistivity are not available.

II. Permeability derived from well test data may be reduced by localized formation damage (skin effects) and increased by Fractures Sedimentlogical data which can be used to predict areal and vertical trends in rock properties and as an aid in the correct choice of core for laboratory measurements.

For core analysis to provide meaningful data, due regard must be given to the ways in which rock properties can change both during the coring procedure (downhole), core preservation, and subsequent laboratory treatment.
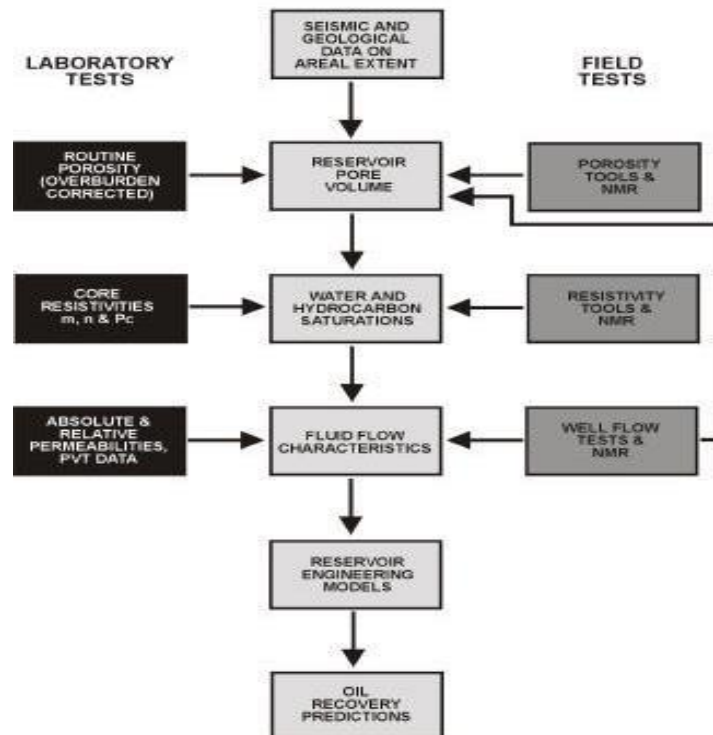
Figure (1.1): Reservoir Engineering Data Resource

Special Core Analysis attempts to extend the data provided by routine measurements to situations more representative of reservoir conditions. SCAL data is used to support log and well test data in gaining an understanding of individual well and overall reservoir performance. However, SCAL measurements are more expensive, and are commonly only done on a small selected group of samples, or if a difficult strategic reservoir management decision has to be made (e.g. to gas flood, or not to gas flood). Tests are carried out to measure fluid distribution, electrical properties and fluid flow characteristics in the two and occasionally three phase situation, and are made on *preserved core*. A schematic diagram of common SCAL measurements is given as Figure 1.2.

Porosity and single phase gas or liquid permeability's are measured at overburden loadings so that the room condition data can be corrected. Wettability and capillary pressure data are generated by controlled displacement of a wetting phase by a non-wetting phase e.g., brine by air, brine by oil or air by mercury. These systems usually have known interfacial tension (IFT) and wetting (contact) angle properties.
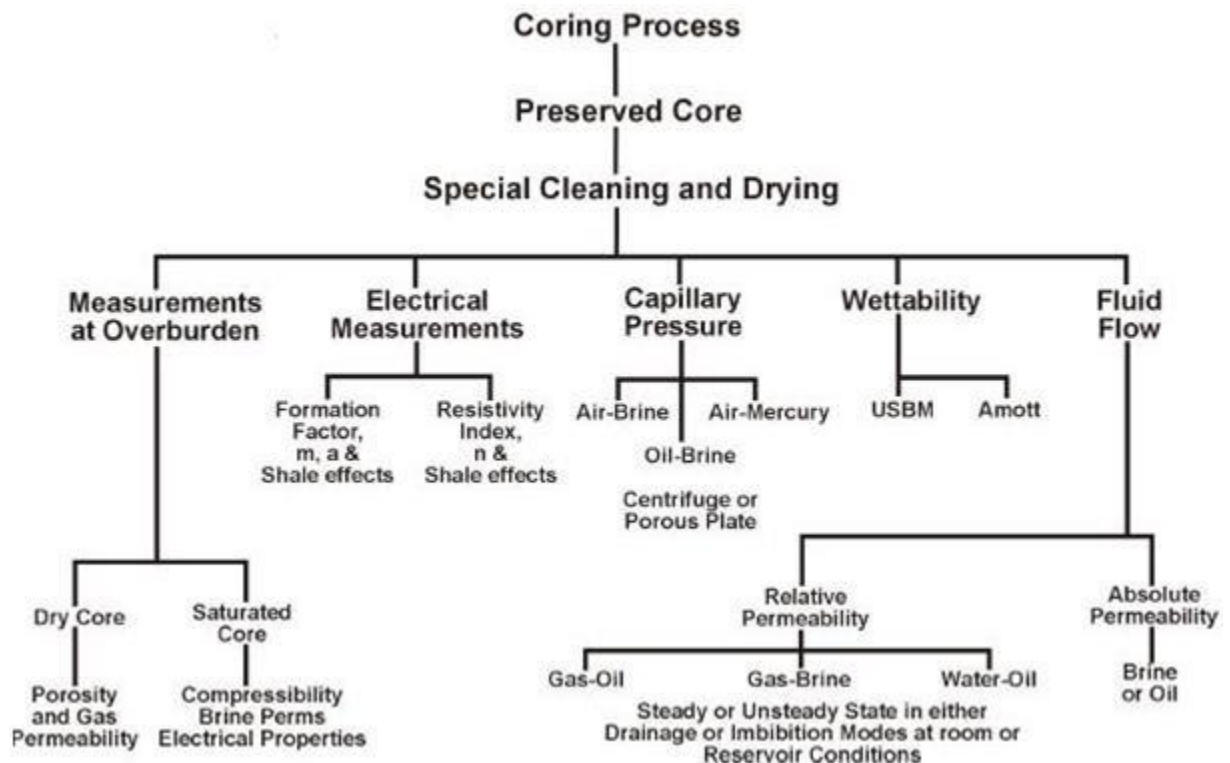
Figure (1.2): SCAL

Today, reservoir simulation has become a standard tool in petroleum engineering discipline and been widely used for solving a variety of fluid flow problems involved in recovery of oil and gas from the porous media of reservoirs. Typical application of reservoir simulation is to predict future performance of the reservoirs so that intelligent decisions can be made to optimize the economic recovery of hydrocarbons from the reservoir. Reservoir simulation can also be used to obtain insights into the dynamic behavior of a recovery process or mechanism. In petroleum engineering area, the numerical solution through the reservoir simulators is often the only way to obtain meaningful and reliable solutions for most actual cases due to extreme complexity of reservoir systems. The numerical solution provides results at discrete points in spatial and temporal domains. Development of a reservoir simulator for different types of reservoir-well systems and recovery processes requires substantial background in mathematics and applied science, which starts with establishing the finite difference equations of a mathematical model for fluid flow in a certain type of reservoir-well system, then followed by numerical modeling and computer programming, and generates simulation software for application to the end. A

schematic diagram of this process is shown in Figure 1.3
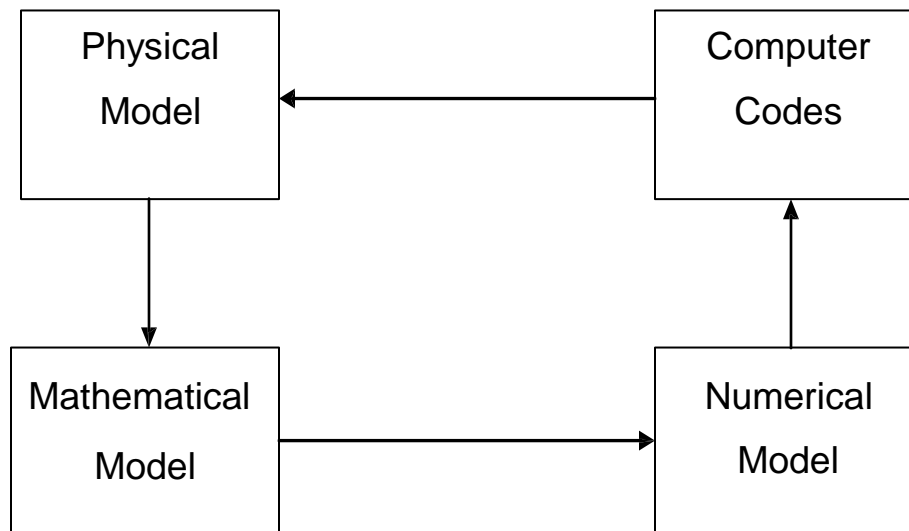
Figure (1.3): Reservoir simulation process

The basic tool for conducting a reservoir simulation study is a simulator. The development of this tool requires a good understanding of the physical processes occurring in reservoirs and a high level of sophistication and maturity in advanced mathematics and computer programming.

There are five basic steps in conducting a reservoir simulation study: -

I. Setting concrete objectives for the study.

II. Selecting the proper simulation approach.

III. Preparing the input data.

IV. Planning the computer runs (including the order in which they occur).

V. Analyzing the results.

1.2. Setting the Objectives:

Setting objectives is the most important step in conducting a simulation study. Clearly defined objectives help us obtain the best information at the lowest cost and in the least amount of time. Improperly set objectives can take the study on a long, roundabout journey which leads to nowhere. There are a number of factors that help us define appropriate objectives. The most important of these are data availability, the required level of detail, availability of technical support and available resources. In setting objectives, we use all of these factors to determine how to proceed.

1.3. Choosing the Simulation Approach:

In choosing *the simulation approach*, we need to consider three basic factors:

a) Reservoir complexity.

b) Fluid type.

c) Scope of the study.

While reservoir complexity and the scope of the study determine the simulator's dimensions and coordinate geometry, the fluid type (together with the processes involved) dictate whether we should use a black-oil model or a more specialized model. For example, predicting well performance in a gas condensate reservoir will require a compositional rather than a black oil simulator.

1.4. Preparing the Input Data:

Because simulation studies usually require large volumes of information from a wide range of sources, preparing the input data can be a laborious task. However, the time spent in ensuring that data are properly prepared is worthwhile, in that it can prevent a great deal of headaches and waste later on in the study. Often, we discover data input errors only after a problem surfaces during the run, which wastes both time and computing resources.

It is our responsibility to ensure internal consistency in the data. Because data come from different sources, internal inconsistencies are not uncommon. We should resolve inconsistencies during the data input preparation. When data inconsistencies are present, they can lead to an ill-posed problem. Even worse, they could go undetected. With an illposedproblem, we may be able to find the inconsistency by the failure of the simulator to run; but in the case of buried inconsistencies, the simulator may run and yield erroneous solutions.Pre-processing capability, particularly for the commercial codes currently available, canfacilitate data preparation. Sometimes these processors have internal checks to flag any detected inconsistencies in the data. While data preparation is the simulation engineer's job, input from other supporting personnel is extremely important. If inconsistencies appear in the data, or even if some data appear doubtful, it is imperative to resolve the problem with the help of the geologist, geophysicist and perhaps the production engineer. In summary, there is no overemphasizing the importance of adequate data preparation prior to making a simulation study. The payoff is exceptionally good.

1.5. Planning the Computer Runs:

Planning computer runs is deceptively simple. To understand the necessity and the complexity of this planning, we only need to imagine a simulation study as a complex roadmap where the traveler knows the point of origin and the destination (these are clear enough from the objectives of the study).

1.6. Analyzing the Results:

When we have analyzed the results of the simulation study and made pertinent inferences from it, we can evaluate its success. This step caps all the efforts previously discussed. Considering the amount of effort that we expend on the simulation study up to this point, it is tempting to become a biased arbiter of the results.

1.7. Objective:

The objective of this research is to:

i.   Compare between excel result and RPNP result .

ii.   Develop a computer program to do normalization and averaging relative permeability data to :
  ❖ Save time.
  ❖ Save effort.
  ❖ Cost optimization.

1.8. Problem Statement:

After SCAL data gathering stage we will analyze the data by review the data, Qc the data (check consistence of the data and determined SCAL data gab. There are several ways to prepare the data to be in simulator form but it take a lot of time, effort and cost.

Chapter Two:

Literature Review

2.1. Introduction:

In the past 30 years, reservoir simulation has evolved from a research area into one of the most flexible and widely used tools in reservoir engineering. Use of reservoir simulation has grown because of its ability to predict the future performance of oil and gas reservoirs over a wide range of operating conditions. Reservoir simulators use numerical methods and high-speed computers to model multidimensional fluid flow in reservoir rock. Reliable simulators and adequate computing capacity are available to most reservoir engineers, so simulation is usually practical for all reservoir sizes and all types of reservoir performance studies. Although the use of simulation frequently is optional, it may be the only reliable way to predict the performance of a large, complex reservoir, especially if such external considerations as government regulations influence the production schedule. Even for small reservoirs where simple calculations or extrapolations may be adequate, simulation is often faster, cheaper, and more reliable than alternative methods for predicting performance.(*Calvin C. Mattax and Robert L. Dalton1990*)

Reservoir studies seeking to interpret and define both geological and engineering parameters dictate the core-analysis program. Core analyses must integrate with field and production data and eliminate reservoir uncertainties that cannot be addressed with log, well-test, or seismic data. These requirements define the coring objectives that, in turn, control coring fluid, tools, and core handling. In most cases, these objectives cannot be obtained with core retrieved in a single well. Coring is thus an integral part of the reservoir-life-cycle process, with cored wells selected to verify or provide maximum information for the current geological, engineering, or production model of the reservoir (*ServetUnalmiser and James J. Funk 1989)* .

Core analysis is a recent development in the field of petroleum technology. The earliest work on this subject was done in connection with evaluating and planning secondary oil recovery by water-flooding. Present-day analysis of sands of flush fields

requires new and independent interpretations of the data provided by cored material. Particular attention is being paid to the development of rapid, routine methods for measuring physical characteristics of sandstone, such as permeability, porosity and grain size, as well as the sand's fluid content *(Howard C. Pyle and John E. Sherborne 1939)* .

SCAL data, specifically, capillary pressure **(Pc)** and relative permeability **(Kr)** are primary inputs to the reservoir simulation model, the predictions of which are used to guide management's field development decisions towards maximizing productivity and ultimate oil recovery *(Meissner et al. 2009).* The appropriateness of those decisions is partially dependent on the accuracy of the simulation model. February 2008, ZADCO's initiated a multiyear project to provide representative SCAL measurements for the simulation model. Rock sample acquisition and selection was an importance aspect of the project. The samples must be sufficient in number for the number of experiments planned, representative of the reservoir and prioritize static reservoir rock types (SRTT) which have the highest impact on reservoir flow dynamics and storage capacity *(Hesham T. Shebl et al 2014)*

There have been recently substantial advances in Pore Scale Physics Discipline. These advances can now be used for the benefit of special core analysis (SCAL) measurements and interpretations. This paper is devoted to explain these improvements from two perspectives: (i) Pore scale imaging and network extraction (ii) Fluid flow modeling applied on the extracted networks in order to predict some key petro-physical properties (capillary pressures, relative permeability) , *(V.S. Suicmez and M. Touati 2007) .*

Converting Laboratory Capillary Pressure Data to Reservoir Conditions, Basic equations:

$$P_{cl} = \frac{2\,\sigma_L cos\theta_L}{r_L} \qquad\qquad (2.1)$$

$$P_{cR} = \frac{2\,\sigma_R cos\theta_R}{r_R} \tag{2.2}$$

Averaging Capillary Pressure Data Using the Leverett J-FunctionA universal capillary pressure curve is impossible to generate because of the variation of properties affecting capillary pressures in reservoir. The Leverett J-function was developed in an attempt to convert all capillary pressure data to a universal curve.J-function is useful for averaging capillary pressure data from a given rock type from a given reservoir. And sometimes it can be extended to different reservoirs having same lithology's. Usually does not predict an accurate correlation for different lithologies. And it is not successful in reducing the scatter in a given set of data, and then this suggests that we are dealing with different rock types.

$$J_{(sw)} = \frac{0.22P_c}{\sigma\,cos\,\theta}\sqrt{\frac{K}{\emptyset}} \tag{2.3}$$

Whole core analysis is critical for characterizing porosity and directional permeability in heterogeneous, fractured, and/ or anisotropic rocks. Whole core measurements are essential for heterogeneous reservoirs because small-scale heterogeneity may not be appropriately represented in plug measurements. For characterization of multi-phase flow properties (special core analysis) in heterogeneous rocks, whole core analysis is also required *(M.M. Honarpour , N.F. Djabbarah and K. Sampath 2003)*

Mathematical correlation has been widely used in oil and gas industry to model relative permeability and capillary pressure from water saturation. The application of mathematical correlation is essential especially in the absence of laboratory data. Additionally, the correlation is also applied to generate a refined relative permeability and capillary pressure table as the input to reservoir simulation *(I. H. Arief , LiliXueand F. Lomeland 2016)*

Results of relative permeability tests performed on several core samples of a reservoir rock often vary. Therefore, it is necessary to average the relative permeability data obtained on individual rock samples. Prior to usage for oil recovery prediction, the relative permeability curves should first be normalized to remove the effect of different initial water and critical oil saturations. The relative permeability can then be de-normalized and assigned to different regions of the reservoir based on the existing critical fluid saturation for each reservoir region, **(Tarek Ahmed 2010)**.

L.P. Dake (1979) state the effective permeability plots can be normalized by dividing the scales by the value of the absolute permeability k to produce the relative permeability's

$$k_{ro}(S_w) = \frac{k_o(S_w)}{k} \tag{2.4}$$

$$k_{rw}(S_w) = \frac{k_w(S_w)}{k} \tag{2.5}$$

Relative permeability's are used as a mathematical convenience since in a great many displacement calculations the ratio of effective permeability's appears in the equations, which can be simplified as the ratio of:

$$\frac{k_o(S_w)}{k_w(S_w)} = \frac{k * k_{ro}(S_w)}{k * k_{rw}(S_w)} = \frac{k_{ro}(S_w)}{k_{rw}(S_w)} \tag{2.6}$$

2.2. Porosity:

The porosity of a rock is a measure of the storage capacity (pore volume) that is capable of holding fluids. Quantitatively, the porosity is the ratio of the pore volume to the total volume (bulk volume). This important rock property is determined mathematically by the following generalized relationship:

$$\emptyset = \frac{pore\ volume}{bulk\ volume} \tag{2.7}$$

Where:

$\emptyset$ ≡ Porosity

As the sediments were deposited and the rocks were being formed during past geological times, some void spaces that developed became isolated from the other void spaces by excessive cementation. Thus, many of the void spaces are interconnected while some of the pore spaces are completely isolated. This leads to two distinct types of porosity, namely:

- ✓ Absolute porosity.
- ✓ Effective porosity.

2.2.1 Absolute porosity:

The absolute porosity is defined as the ratio of the total pore space in the rock to that of the bulk volume. A rock may have considerable absolute porosity and yet have no conductivity to fluid for lack of pore interconnection. The absolute porosity is generally expressed mathematically by the following relationships:

$$\emptyset_a = \frac{total\ pore\ volume}{bulk\ volume} \qquad (2.8)$$

Where:

$\emptyset_a$ ≡ Absolute porosity.

2.2.2 Effective porosity:

The effective porosity is the percentage of interconnected pore space with respect to the bulk volume, or

$$\emptyset = \frac{interconnected\ pore\ volume}{bulk\ volume} \qquad (2.9)$$

Where:

$\emptyset$ ≡ Effective porosity.

2.3. Permeability:

The Permeability is a property of the porous medium and it is a measure of capacity of the medium to transmit fluids. Permeability is a tensor that in general is a function of

pressure. Usually the pressure dependence is neglected in reservoir calculations. But the variation with position can be pronounced. Very often the permeability varies by several magnitudes, and such heterogeneity will of course influence any oil recovery. So permeability is a very important rock property because it controls the directional movement and the flow rate of the reservoir fluids in the formation. It does not a pear in the volumetric equation. It is a measure of how easily single fluid (gas or liquid) will flow through the connected pore spaces when a pressure gradient is applied. It is an important parameter that controls the reservoir performance. It importance is reflected by the number of available techniques typically used to estimate it. These different techniques provide formation permeability that represents different averaging volumes.

Darcy (1856) performed a series of experiments on the relationship affecting the downward flow of water through sands. The generalized equation called Darcy's law can be written in the form:

$$\bar{u} = -\frac{\bar{\bar{k}}}{\mu}(\nabla P + \rho \bar{g}) \tag{2.10}$$

Where:

$\bar{u}$ ≡ Superficial velocity.

$\bar{\bar{k}}$ ≡ Permeability tensor.

μ ≡ Fluid viscosity.

∇P ≡ Pressure gradient.

ρ ≡ Fluid density.

$\bar{g}$ ≡ Gravitational vector.

The permeability, k, of a reservoir rock is related to the volumetric flow rate, Q, through the rock by the means of Darcy law:

$$K = \frac{q\mu\Delta L}{A\Delta P} \tag{2.11}$$

Where:

q ≡Volumetric flow rate (ml/s)

K ≡ Air permeability (mD)

μ ≡ Fluid viscosity (c.P)

A ≡ Cross - sectional area (cm^2)

ΔP ≡ Pressure differential (psi)

ΔL ≡ Unit length

ρ ≡ Density ($\frac{lb}{ft^3}$)

g ≡ Gravity acceleration ($\frac{ft}{s^2}$)

The dimensions of permeability can be established by substituting the dimensions of the parameters in the equation. The unit Darcy results from the choice of **Cgs** system units

$$darcy[D] = \frac{q\left[\frac{cm^3}{s}\right]\mu[cp]L[cm]}{\Delta P[atm].A[cm^2]} \qquad (2.12)$$

The permeability has a dimension of L² and the permeability in SI system has units ofm^2.

This permeability is more properly termed specific (or absolute) permeability.

It's of a reservoir when the fluid fills 100 percent of the pore space. Absolute permeability (K) is not usually directly applicable to petroleum industry. Essentially all reservoirs, whether they produce oil or gas, contain at least two components Hydrocarbon and water. Calculations relating to reservoir conditions require effective permeability

The Effective permeability is the ability of the porous material to conduct a fluid when it's saturation is less than 100% of the pore space. Effective permeability (Ke) may replace Specific permeability in equation (2.11) when the conditions are specified under which the permeability applies. The main "condition" in this regards is the fluid

saturation. For this reason, there is another permeability measure termed relative permeability.

2.3.1. Absolute permeability:

When the medium is completely saturated with one fluid, then the permeability measurement is often referred to as specific or absolute permeability. Absolute permeability is often calculated from the steady-state flow equation:

$$k = \frac{q\,\mu\,l}{A\,\Delta p} \tag{2.13}$$

Where:

k = proportionality constant, or permeability, (Darcy's).

μ = viscosity (cp).

q = flow rate through the porous medium, (cm^3/sec).

l = length of core, (cm).

A = cross-sectional area, (cm^2).

2.3.2. Effective Permeability:

When the rock pore spaces contain more than one fluid, then the permeability to a particular fluid is called the effective permeability.

Effective permeability is a measure of the fluid conductance capacity of a porous medium to a particular fluid when the medium is saturated with more than one fluid.

Calculating Effective Permeability:

Oil $\quad\Longrightarrow\quad k_{eo} = \frac{q_o * \mu_o * L}{A\,\Delta P_o}$ $\tag{2.14}$

Water $\quad\Longrightarrow\quad k_{ew} = \frac{q_w * \mu_w * L}{A\,\Delta P_w}$ $\tag{2.15}$

Gas $\quad\Longrightarrow\quad k_{eg} = \frac{q_g * \mu_g * L}{A\,\Delta P_g}$ $\tag{2.16}$

2.4. Saturation:

Saturation is defined as that fraction, or percent, of the pore volume occupied by a particular fluid (oil, gas, or water). This property is expressed mathematically by the following relationship:

$$fluid\ saturation = \frac{total\ volume\ of\ the\ fluid}{pore\ volume} \qquad (2.17)$$

Applying the above mathematical concept of saturation to each reservoir fluid gives:

$$S_o = \frac{volume\ of\ oil}{pore\ volume} \qquad (2.18)$$

$$S_g = \frac{volume\ of\ gas}{pore\ volume} \qquad (2.19)$$

$$S_w = \frac{volume\ of\ water}{pore\ volume} \qquad (2.20)$$

Where:

S_o = oil saturation

S_g = gas saturation

S_W = water saturation

Thus, all saturation values are based on pore volume and not on the gross reservoir volume.

The saturation of each individual phase ranges between zero to 100 percent. By definition, the sum of the saturations is 100%, therefore: **$S_g + S_o + S_W = 1.0$**

2.5. Overburden pressure:

Overburden pressure, also called lithostatic pressure, confining pressure or vertical stress, is the pressure or stress imposed on a layer of soil or rock by the weight of overlying material.

The overburden pressure at a depth z is given by:

$$p(z) = p_0 + g \int_0^z \rho(z)\, dz \tag{2.21}$$

Where: p(z) is the density of the overlying rock at depth z and g is the acceleration due to gravity. p_0 is the datum pressure, the pressure at the surface. In deriving the above equation, it is assumed that gravitational acceleration *g* is a constant over *z*, since it is placed outside the integral. In reality, *g* is a (non-constant) function of *z* and should appear inside the integral. But since *g* varies little over depths which are a very small fraction of the Earth's radius, it is placed outside the integral in practice for most near-surface applications which require an assessment of lithostatic pressure. In deep-earth geophysics/geodynamics, gravitational acceleration varies significantly over depth and *g* may not be assumed to be constant.

2.6. Capillary pressure:

The pressure difference existing across the interface separating two immiscible fluids.

Capillary pressure = (pressure of the non-wetting phase)−(pressure of the wetting phase)

$$P_c = P_{nw} - P_w \tag{2.22}$$

That is, the pressure excess in the non-wetting fluid is the capillary pressure, and this quantity is a function of saturation. This is the defining equation for capillary pressure in a porous medium. There are three types of capillary pressure:

- Water-oil capillary pressure (denoted as P$_{cwo}$)$\boldsymbol{P_{cwo} = P_o - P_w}$
- Gas-oil capillary pressure (denoted asP$_{cgo}$)$\boldsymbol{P_{cgo} = P_g - P_o}$
- Gas-water capillary pressure (denoted as P$_{cgw}$) $\boldsymbol{P_{cgw} = P_g - P_w}$

2.7. Relative permeability:

If a formation contains two or more immiscible fluids, each fluid tends to interfere with the flow of others. This reduction in ability of a fluid to flow through a permeable material is called a relative permeability effect. In other words; it is the ratio of the effective permeability of a given phase. say oil K$_o$. in presence of other phases (water and/or gas). to the absolute permeability k.

$$k_{ro} = \frac{k_o}{k} \tag{2.23}$$

$$k_{rg} = \frac{k_g}{k} \tag{2.24}$$

$$k_{rw} = \frac{k_w}{k} \tag{2.25}$$

Where:

K=the absolute permeability.

k_{ro}, k_{rw}, k_{rg} Is the relative permeability for oil, water, gas respectively.

k_o, k_w, k_g Is the effective permeability for oil, water. gas respectively.

There are many Factors Affecting Effective and Relative Permeability's:

I.   Fluid saturations.

II.   Geometry of the rock pore spaces and grain size distribution.

III.   Rock wettability Figure (2.1).

IV.   Fluid saturation history (i.e., imbibition or drainage).

Effect of wettability on relative permeability:
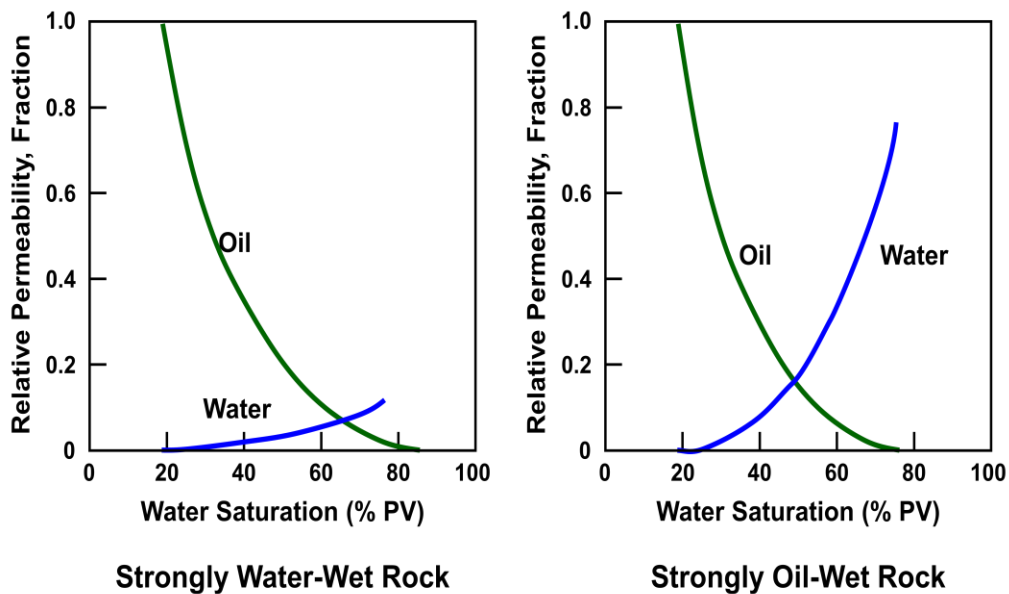
Figure (2.1): Effect of Wettability on Relative Permeability:

Relative permeability curves are of extreme importance to reservoir evaluations due to their ability to predict fluid production during reservoir exploration. They established, for any particular phase, a functional dependence between phase saturation and the rock's ability to produce. These curves are determined in special core laboratories analysis through a sequence of standard measurements and calculations generally performed using some adaptations of frontal advance theory. Conceptually, this theory requires pressure gradients and fluid saturations at the production phase of the sample, leading to a set of

calculated relative permeability values that are function of point saturation. Also the development of representative relative permeability curves is the single most important step in developing an accurate history match and in accurately predicting future performance. Often, the absence of relative permeability data forces the engineer to seek analog data from offset rocks which will hopefully represent the fluid flow characteristics within the reservoir of interest.

Oil and water relative permeability's in an oil-water system are usually plotted as function to water saturation as shown in figure (2.2).
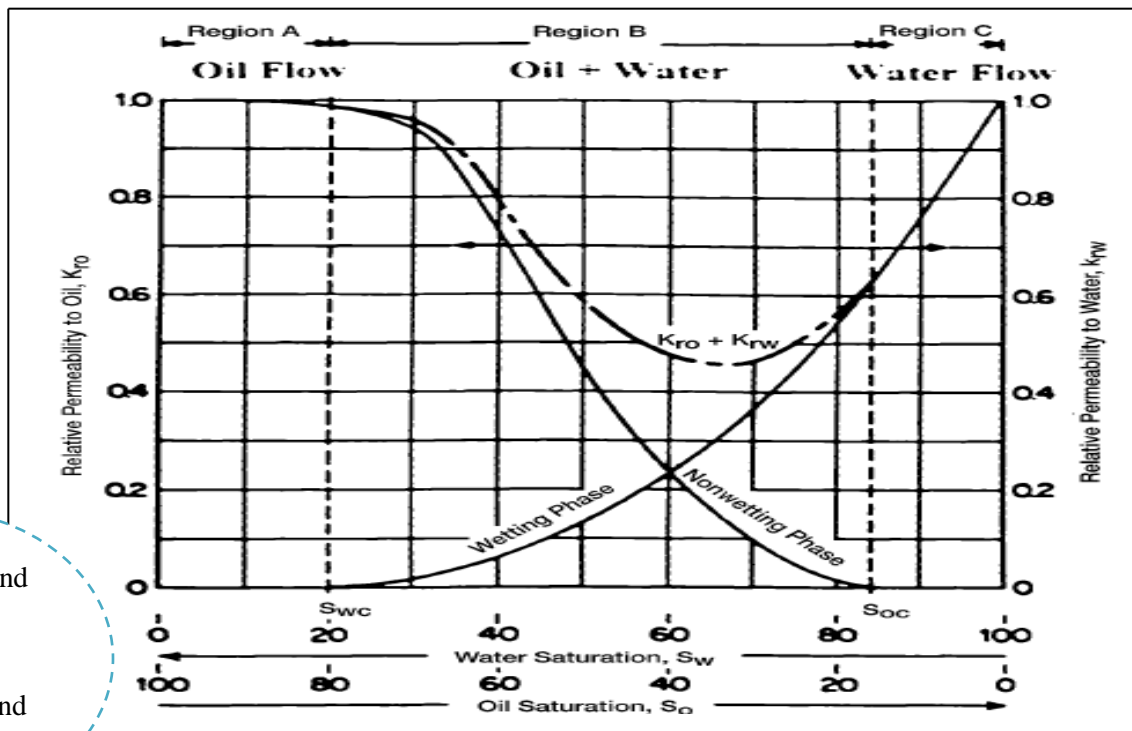
Region A: The end point fluid saturation

Region B: The end point

Figure (2.2):typical tow phase behavior (Tarek Ahmad)

The end points of this curve can be described as follows:

a. Point 1

Point 1 on the wetting phase relative permeability shows that a small saturation of the non-wetting phase will drastically reduce the relative permeability of the wetting phase. The reason for this is that the non-wetting phase occupies the larger pore spaces, and it is in these large pore spaces that flow occurs with the least difficulty.

b. Point 2

Point 2 on the non-wetting phase relative permeability curve shows that the non-wetting phase begins to flow at the relatively low saturation of the non-wetting phase. The saturation of the oil at this point is called *critical oil saturation* S_{oc}.

c. Point 3

Point 3 on the wetting phase relative permeability curve shows that the wetting phase will cease to flow at a relatively large saturation. This is because the wetting phase preferentially occupies the smaller pore spaces, where capillary forces are the greatest. The saturation of the water at this point is referred to as the *irreducible water saturation* S_{wir} or *connate water saturation* S_{wi} — both terms are used interchangeably.

d. Point 4

Point 4 on the non-wetting phase relative permeability curve shows that, at the lower saturations of the wetting phase, changes in the wetting phase saturation have only a small effect on the magnitude of the non-wetting phase relative permeability curve. The reason for the phenomenon at Point 4 is that at the low saturations the wetting phase fluid occupies the small pore spaces which do not contribute materially to flow, and therefore changing the saturation in these small pore spaces has a relatively small effect on the flow of the non-wetting phase. This process could have been visualized in reverse just as well. It should be noted that this example portrays oil as non-wetting and water as wetting. The curve shapes shown are typical for wetting and non-wetting phases and may be mentally reversed to visualize the behavior of an oil-wet system. Note also that the total permeability to both phases, $k_{rw} + k_{ro}$, is less than 1, in regions B and C.

The directions of the curves point out the saturation histories which are called drainage and imbibition's. As it is shown in fig (2.3) drainage curve applies to processes where the wetting phase is decreasing. The imbibition's curve applies to processes where the wetting phase is increasing.
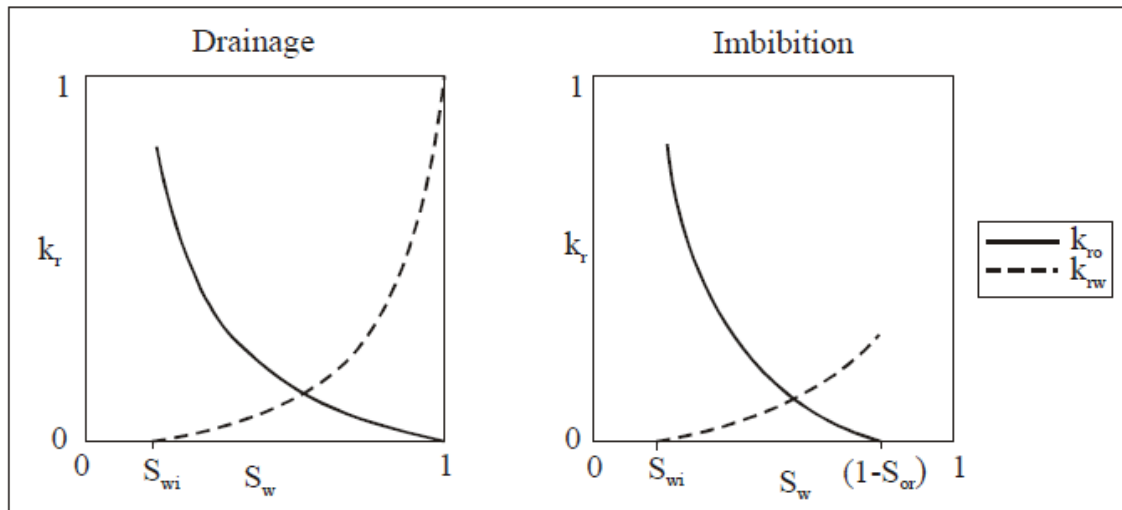
Figure (2.3): Typical curves for oil-water relative permeability at a water-wetted system. (After O. Torsater& M. Abrahi)

It is generally agreed that the pore spaces of reservoir rocks were originally filled with water, after which oil moved into the reservoir, displacing some of the water, and reducing the water to some residual saturation. When discovered, the reservoir pore spaces are filled with connate water saturation and oil saturation. If gas is the displacing agent, then gas moves into the reservoir, displacing the oil. This same history must be duplicated in the laboratory to eliminate the effects of hysteresis. The laboratory procedure is to first saturate the core with water, then displace the water to a residual or connate, water saturation with oil after which the oil in the core is displaced by gas. This flow process is called the gas drive, or drainage, depletion process. In the gas drive depletion process, the non-wetting phase fluid is continuously increased, and the wetting phase fluid is continuously decreased.

   The imbibition process is performed in the laboratory by first saturating the core with the water (wetting phase), then displacing the water to its irreducible (connate) saturation by injection oil. This "drainage" procedure is designed to establish the original fluid saturations that are found when the reservoir is discovered. The wetting phase (water) is reintroduced into the core and the water (wetting phase) is continuously increased. This is the imbibition process and is intended to produce the relative permeability data needed for water drive or water flooding calculations.

   Figure (2.4) schematically illustrates the difference in the drainage and imbibition processes of measuring relative permeability. It is noted that the imbibition technique causes the non-wetting phase (oil) to lose its mobility at higher values of water saturation than does the drainage process. The two processes have similar effects on the wetting phase (water) curve. The drainage method causes the wetting phase to lose its mobility at higher values of wetting-phase saturation than does the imbibition's method.
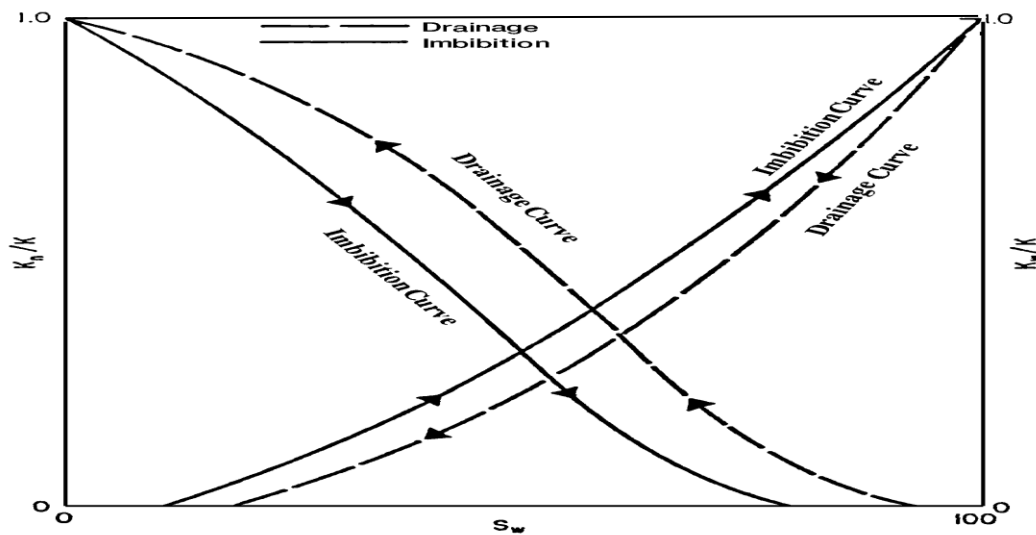
Figure (2.4): Hysteresis effects in relative permeability.

2.7.1. Corey's Method:

Corey (1954) proposed a simple mathematical expression for generating the relative permeability data of the gas-oil system. The approximation is good for drainage processes, i.e., gas-displacing oil.

$$k_{ro} = (1 - S_g^*)^4 k_{rg} = (S_g^*)(2 - S_g^*) \tag{2.26}$$

Where the effective gas saturation S_g^* is defined

$$S_g^* = \frac{S_g}{1 - S_{wc}} \tag{2.27}$$

Corey (1954) proposed that the water-oil relative permeability can be represented as follows:

$$K_{ro} = \left(\frac{1 - S_w}{1 - S_{wc}}\right)^4 \tag{2.28}$$

$$K_{rw} = \left(\frac{S_w - S_w}{1 - S_{wc}}\right)^4 \tag{2.29}$$

<u>Or:</u>

$$(k_{ro})^{0.25} = \left(\frac{1 - S_w}{1 - S_{wc}}\right) \tag{2.30}$$

$$(k_{rw})^{0.25} = \left(\frac{S_w - S_w}{1 - S_{wc}}\right) \tag{2.31}$$

The last two expressions suggest that a plot of $K_{ro}^{0.25}$ and $K_{rw}^{0.25}$ versus S_w would produce straight lines with the following end values:

$$K_{ro} = 1.0 @ S_{wc}$$
$$K_{rw} = 1.0 @ S_{wc} = 1.0$$
$$K_{ro} = 0.0 @ S_{wc} = 1.0$$
$$K_{rw} = 0.0 @ S_{wc}$$

It should be pointed out that Corey's equations apply only to well-sorted homogeneous rocks. To account for the degree of consolidation, the exponent of the relationships can be expressed in a more generalized way:

$$K_{ro} = \left(\frac{1 - S_w}{1 - S_{wc}}\right)^n \tag{2.32}$$

$$k_{rw} = \left(\frac{S_w - S_{w}}{1 - S_{wc}}\right)^m \tag{2.33}$$

Taking the logarithm of both sides of the previous two expressions gives:

$$\log(K_{ro}) = n \log \frac{1 - S_w}{1 - S_{wc}} \tag{2.34}$$

$$\log(K_{rw}) = m \log \frac{S_w - S_w}{1 - S_{wc}} \tag{2.35}$$

The exponent's n and m represent slopes of the two straight lines resulting from plotting k_{ro} and k_{rw} versus the term in parentheses on a log-log scale.

2.8. Wettability:

Wettability is defined as the tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids. The tendency of a liquid to spread over the surface of a solid is an indication of the *wetting* characteristics of the liquid for the solid. This spreading tendency can be expressed more conveniently by measuring the angle of contact at the *liquid-solid* surface. This angle, which is always measured through the liquid to the solid, is called the contact angleθ. The contact angle θ has achieved significance as a measure of wettability. As shown in Figure (2.5), as the contact angle decreases, the wetting characteristics of the liquid increase. Complete wettability would be evidenced by a zero contact angle, and complete non-wetting would be evidenced by a contact angle of 180°. There have been various definitions of *intermediate* wettability but, in much of the published literature, contact angles of 60° to 90° will tend to repel the liquid.
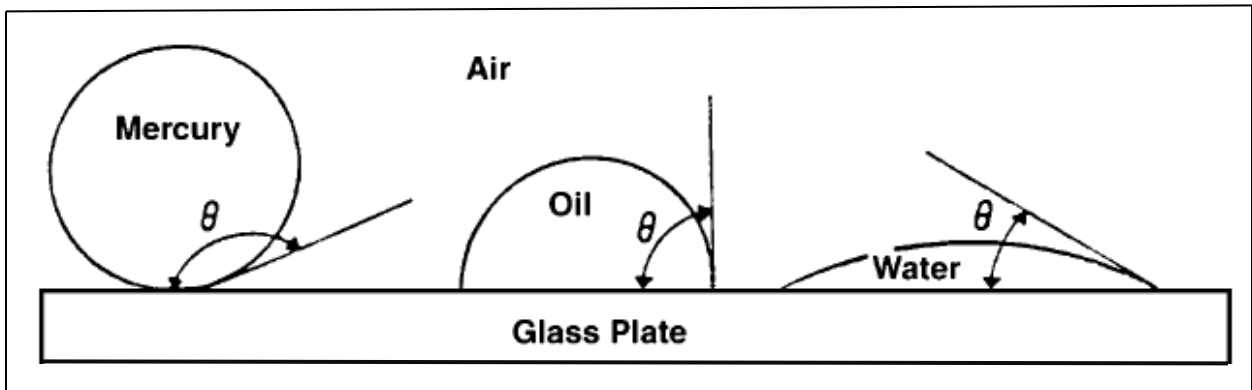
Figure (2.5): Illustration of wettability.

2.9. Surface and interfacial tension:

The term *surface tension* is used to describe the forces acting on the interface. When the interface is between two liquids, the acting forces are called *interfacial tension.* Consider the two immiscible fluids, air (or gas) and water (or oil) as shown schematically in Figure (2.6). A liquid molecule, which is remote from the interface, is surrounded by other liquid molecules, thus having a resulting net attractive force on the molecule of zero. A molecule at the interface, however, has a force acting on it from the air (gas) molecules lying immediately above the interface and from liquid molecules lying below the interface.
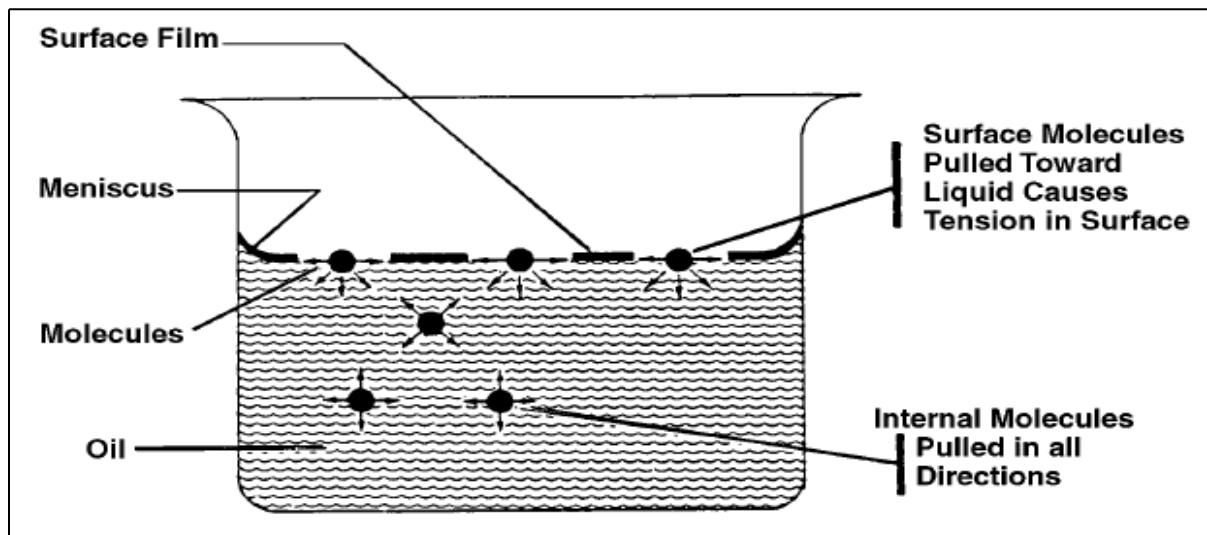
Figure (2.6): Illustration of surface tension. (*After Clark, N. J.,* Elements of Petroleum Reservoirs, *SPE, 1969.*)

There are many methods for measurement of Permeability these methods are:

I.   Core data.

II.   Well test data.

III.   Log data (RFT and MDT).

IV.   Production data.

2.10. Permeability from the core:

All laboratory methods for determining permeability rely on a measurement or an interpretation of a flow rate through and a pressure drop across a sample of known length and cross sectional area, for a fluid of known viscosity. This data is then analyzed by means of Darcy law. In theory, the nature of the fluid should not be important: however, in practice, the nature of the fluid is very important if the rock and fluid interact.

The measurement method for permeability, may be divided into classes based on the sample type (plug or full Demeter core), the fluid used (gas or liquid), and the technique (Steady or unsteady state conditions). The sample type controls the amount and quality of information that can be standard laboratory analysis procedures will generally provide reliable data on permeability of core samples. If the rock is not homogeneous, the whole core analysis technique will probably yield more accurate results than the analysis of core plugs (small pieces cut from the core). Procedures that have been used for improving the accuracy of the permeability determination include cutting the core with an oil-base mud. employing a pressure-core barrel, and conducting the permeability tests with reservoir oil Permeability is reduced by overburden pressure, and this factor should be considered in deep wells because permeability is an estimating permeability of the reservoir rock in the system, that is isotropic property of porous rock in some defined regions of the system that is, it is directional. Routine core analysis is generally concerned with plug samples drilled parallel to bedding planes and, hence, parallel to direction of flow in the reservoir. These yield horizontal permeability's (K_h).The measured permeability on plugs that are drilled perpendicular to bedding planes are referred to as vertical permeability (K_v).

There are several factors that must be considered as possible sources of error in determining reservoir permeability.

These factors are:

A. Core sample may not be representative of the reservoir rock because of reservoir heterogeneity.

B. Core recovery may be incomplete.

C. Permeability of the core may be altered when it is cut, or dried in preparation for analysis. This problem is likely to occur when the rock contains reactive clays.

D. Sampling process may be biased. There is a temptation to select the best parts of the core for analysis.

Permeability is measured by passing a fluid of known viscosity μ through a core plug of measured dimensions (A and L) and then measuring flow rate q and pressure drop Δp solving Equation 2.36 for the permeability, gives:

$$K = \frac{q\mu L}{A\Delta P} \tag{2.36}$$

The following conditions must exist during the measurement of permeability:

❖ *Laminar (viscous) flow.*

❖ *No reaction between fluid and rock.*

❖ *Only single phase present at 100% pore space saturation.*

There are two types of instruments are usually used in the laboratory:

A. Variable head permeameter.

B. Constant head permaeameter, Core Laboratories type.

Permeability tests are performed on samples which have been cleaned and dried and a gas (usually air) is used for flowing fluid in the test. This is because:

1. Steady state is obtained rapidly.

2. Dry air will not alter the minerals in the rock, and

3. 100% fluid saturation is easily obtained.

Measured values using constant head equipment range from a low of 0.1 MD to 20 D. Data accuracy declines at high and low permeability values and is within 0.5% of true value otherwise.

2.10.1. Constant Head Permeameter:

This equipment is designed for plug or whole core permeability measurements. This experiment may be used for single or multiphase, compressible fluid or liquid measurements and can also be used under reservoir pressure and temperature.

Figure (2.7) shows a diagram of a constant head permeameter. Air is usually used as gas flow upstream and downstream pressures are measured by manometers on both sides of the core and air flow is measured by means of a calibrated outlet. Air permeability can then be calculated using Equation:

$$Q_{atm} = \frac{AK(p_1^2 - P_2^2)}{\mu L 2 P_{atm}}$$

(2.37)

1. Air supply
2. Reduction valves
3. Core holder
4. Core sample
5. Manometers
6. Sleeve pressure
7. Wet-test meter (gas-volume measurement)
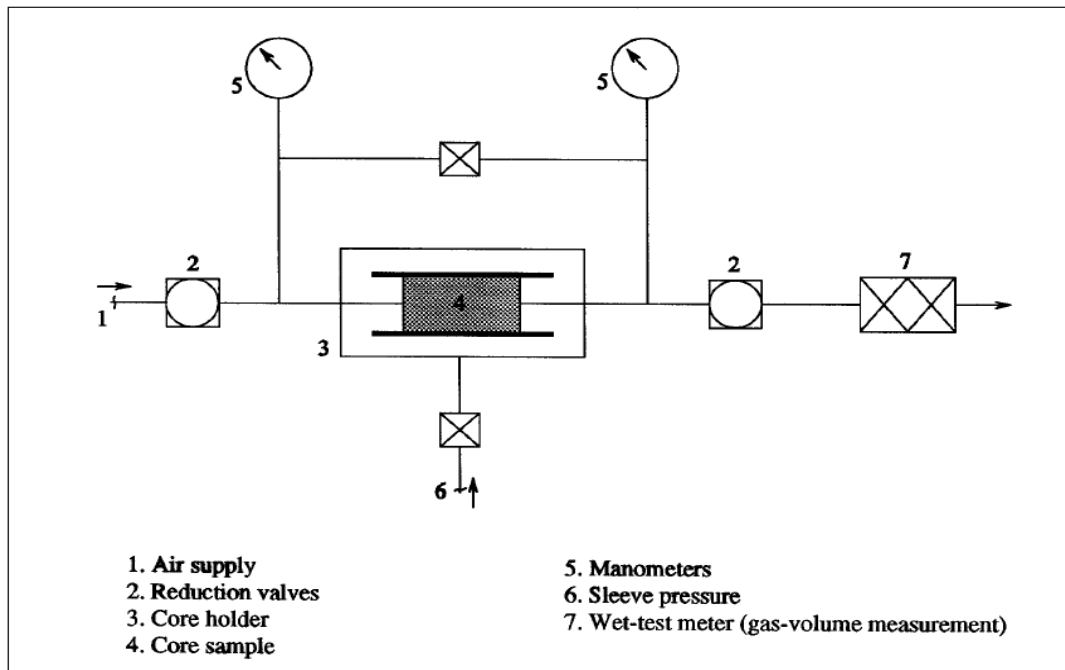
Figure(2.7) (Schematic Diagram of Permeameter*(After O.Torsater& M. Abrahi)*

Hassler core holder may be used with this instrument. Hassler system isthe improvement of the rubber plug system whose tightness is limited at certain pressures. The core is placed in a flexible rubber tube figure (2.8) the hassler cell has these advantages:

I. Excellent tightness.
II. Can be used for samples of different sizes Much higher pressure or ΔP.
III. Can be used Can be used for measuring relative permeability.

Darcy's equation may be used for determining permeability of liquids. The volumetric flow rate q is constant for liquids, because the density does not change during flow through the core.

❖ **Description**:

The constant head permeameter with the Hassler cell is used to measure the permeability.

❖ **Procedure:**

The measured air permeability is influenced by the mean pressure Pm of the core. The mean pressure is regulated by the upstream and downstream values on the sides of Hassler cell. The rate is measured at atmospheric conditions with a mass flow meter in percent of maximum rate which is 200 1/hour Four measurements of air permeability will be taken at different pressures. It is important to keep the ΔP constant, because the air flow at the core sample must be laminar. It is best to have relative little pressure difference, ΔP. To avoid turbulent flow .a use maximal ΔP = 0.2 bar.
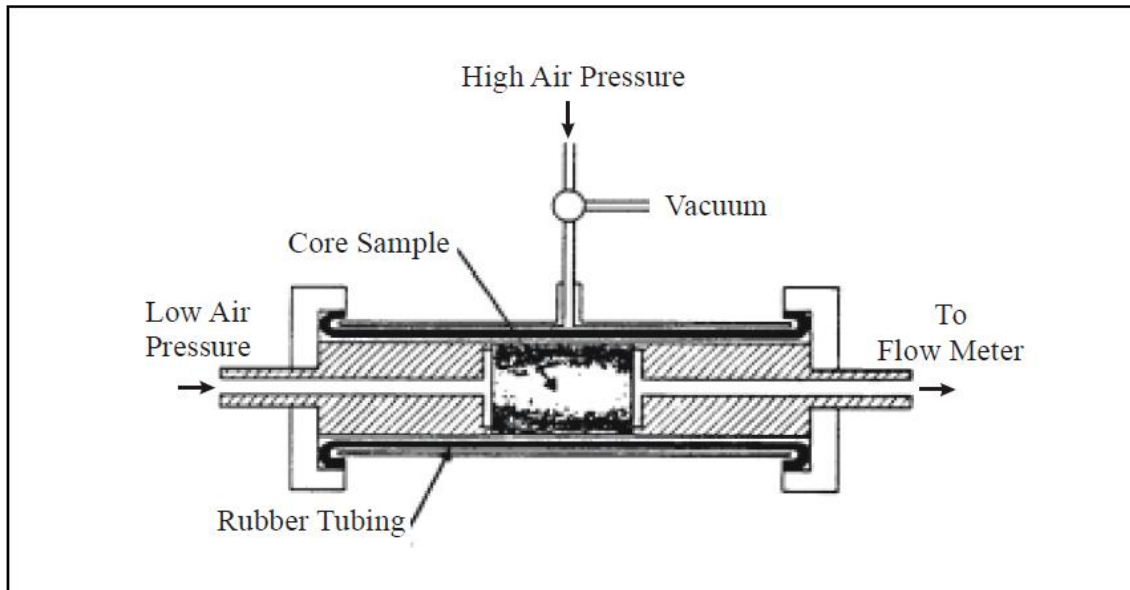
Figure(2.8) : Hassler type core holder. *(After O. Torsater& M. Abrahi)*

2.11. Klinkenberg Effect:

Klinkenberg (1941) discovered that permeability measurements made with air as the flowing fluid showed different results from permeability measurements made with a liquid as the flowing fluid. The permeability of a core sample measured by flowing air is always greater than the permeability obtained when a liquid is the flowing fluid. Klinkenberg postulated, on the basis of his laboratory experiments, that liquids had a zero velocity at the sand grain surface, while gases exhibited some finite velocity at the sand grain surface. In other words, the gases exhibited slippage at the sand grain surface. This slippage resulted in a higher flow rate for the gas at a given pressure differential. Klinkenberg also found that for a given porous medium as the mean pressure increased the calculated permeability decreased.

Mean pressure is defined as upstream flowing plus downstream flowing pressure divided by two, $[pm = (p1 + p2)/2]$. If a plot of measured permeability versus $1/pm$ were extrapolated to the point where $1/pm = 0$, in other words, where $pm = $ infinity, this permeability would be approximately equal to the liquid

permeability. A graph of this nature is shown in Figure (2.9). The absolute permeability is determined by extrapolation as shown in Figure (2.9). The resulting straight-line relationship can be expressed as:

$$K_g = K_L + c\left[\frac{1}{P_m}\right] \qquad\qquad (2.38)$$

Where:

Kg≡Measured gas permeability

P_m≡Mean pressure

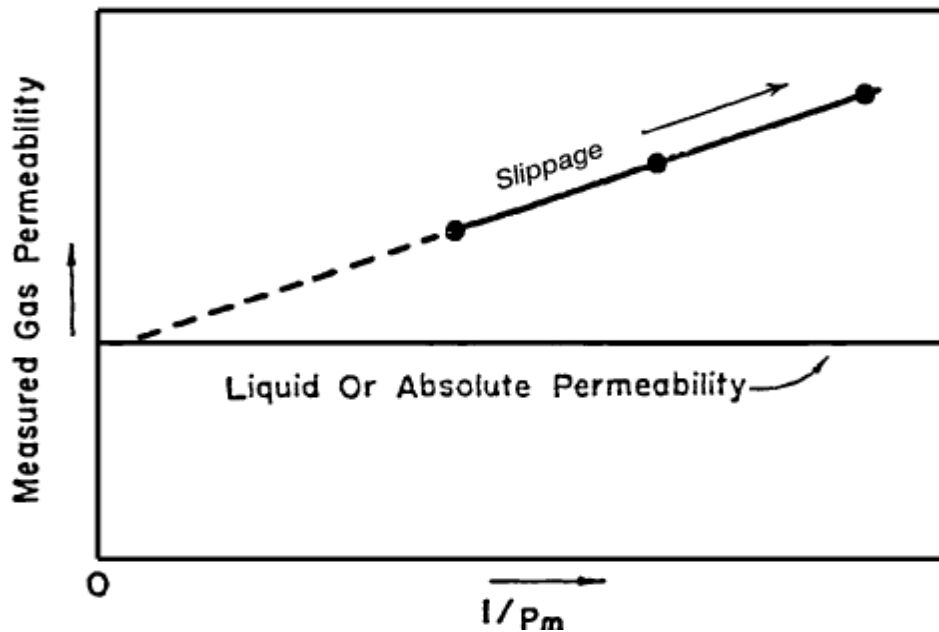K_L≡Equivalent liquid permeability, i.e., absolute permeability, k

c≡Slope of the line

Figure (2.9). The Klinkenberg effect in gas permeability measurements.

2.12. Relative Permeability Measurement Methods:

2.12.1. Steady State Method:

In the steady state two fluids are injected simultaneously at a fixed ratio until the method, produced ratio is equal to the injected ratio. Core saturations have to be measured at each equilibrium and new fluid ratio is applied. This is repeated until the relative permeability's are determined. Most tests are started with the core sample saturated with 100% wetting phase and the test is then a desideration test (drainage). This method, however, will most likely not give the endpoint saturations corresponding to the immobile water saturation or residual oil saturations.

The serious experimental problem with the steady state method is that in situ are several in the core have to be measured or calculated from material balance. There are several methods to measure in situ saturations such as electrical resistance and capacitance methods, physical and chemical methods, nuclear methods, electromagnetic radiation absorption methods, weighing etc. Another problem is capillary end effects. These may be overcome by using high rate of flow and high pressure differential, or each end of the sample is suitably prepared with porous disks and test sections to minimize end effects Advantages of this method are that it is conceptually straightforward and gives relative permeability data for the whole saturation range.

2.12.2. Unsteady State Method:

The procedure for performing an unsteady state test is relatively simple and fast. In the following a water-oil test is described, but the procedure in principle is the same for gasoil or water-gas. First the core is saturated with 100% water and then the sample is desiderated by injecting oil until no more production of water is obtained. Water production is recorded and S_{wi} calculated. Effective oil permeability is then measured at S_{wi}. oil is displaced by a predetermined constant rate of water, oil permeability and pressure drop across the core will be recorded. Alternatively, oils displaced by keeping the differential pressure across the core constant with varying rate of fluid flow. With the recording of cumulative water injection, pressure drop and produced oil volume, it is possible to calculate relative permeability's by theory developed by Welge. Like

steady state method, the pressure across the core must be large enough to make capillary end effects and gravity effects negligible.

✓ <u>Advantages of unsteady state method are:</u>

❖ Substantially quicker than the steady state method.

❖ The process resembles more the mechanisms taking place in the reservoir, and gives better endpoint data.

❖ Simpler experimentally, and better adaptable to reservoir condition applications.

❖ Smaller amounts of fluids required.

✓ <u>The main disadvantages are:</u>

❖ Relative permeability data will not be over the entire saturation range and might in the extreme case restricted to endpoint data only.

❖ Discontinuities in capillary pressure at the core ends may lead to distortion of the pressure data and recovery measured.

❖ Substantially more calculations are necessary, but the mathematics may be solved by computers.

2.13. Flow of Immiscible Fluids in Porous Media:

The concept of relative permeability is fundamental to the study of the simultaneous flow of immiscible fluids through porous media. W_e Consider first the case of linear displacement in a thin tube of porous material inclined at an angle α to the horizontal and with a cross section A. From Darcy's law, for the two phases, oil and water, we have the following equation:

$$q_w = -\frac{K_w A}{\mu_o}\left(\frac{\partial P_w}{\partial_x} + \rho_w g \sin \alpha\right) \tag{2.39}$$

$$q_o = -\frac{K_o A}{\mu_o}\left(\frac{\partial P_o}{\partial_x} + \rho_o g \sin \alpha\right) \tag{2.40}$$

The fluids are considered to be incompressible so that the continuity equation applies to each phase:

$$\frac{\partial q_w}{\partial_x} = -\emptyset A \frac{\partial S_w}{\partial_t} \tag{2.41}$$

$$\frac{\partial q_o}{\partial x} = -\emptyset A \frac{\partial S_o}{\partial t} \tag{2.42}$$

$$S_o + S_w = 1.0 \tag{2.43}$$

By adding above Equation:

$$\frac{d}{\partial x}(q_o + q_w) = 0$$

So that the total flow rate $q_t = q_o + q_w$ is constant along the tube .

Now if the Equation (2.41, 2.42, 2.43) was combined to eliminate P_w and P_o we obtain

$$q_o = -\frac{K_o A}{\mu_o}\left(\frac{\mu_w q_w}{K_w A} + \frac{\partial P_c}{\partial x} - \Delta \rho g \sin \alpha\right) \tag{2.44}$$

We can define fraction f_w of the flowing stream by :

$$f_w = \frac{q_w}{q_o} \ and \ f_o = 1 - f_w \tag{2.45}$$

The substitution of q_w and q_o in equation (2.45) yield

$$f_w = \frac{1 + \frac{K_o A}{\mu_o q_t}(\frac{\partial P_c}{\partial x} - \Delta \rho g \sin \alpha)}{1 + \frac{K_o}{K_w}\frac{\mu_w}{\mu_o}} \tag{2.46}$$

This is the fractional flow equation for the displacement of oil by water. For the displacement in a horizontal reservoir, and neglecting effect of capillary pressure gradient, the fractional flow equation is reduced to be provided the displacement strictly a function of water saturation, as related through the relative permeability's. For typical set of relative permeability's the fractional flow. Equation (2-46), usually has the shape indicated in Figure (2-10) with saturation limit S_{wi} and $(1 - S_{or}.)$ The typical between which the fractional flow increases from zero to unity. The typical function curve as a function of water saturation.
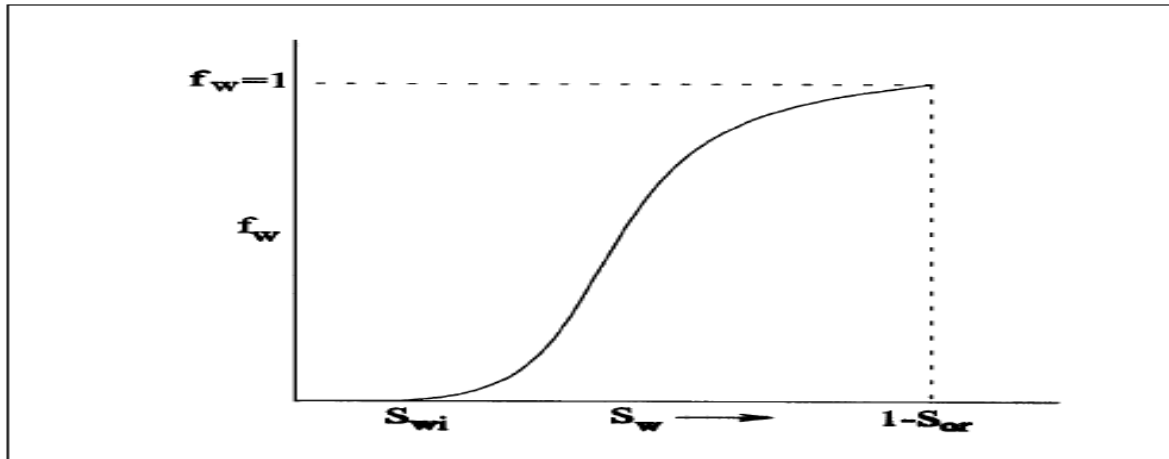
Fig(2.10) Typical fractional flow curve as a function of water saturation.*(After O. Torsater& M. Abrahi)*

2.14. Permeability from the well Testing:

The transient pressure testing measures permeability base on different test Types:

- Short-term testing (DST)
- Conventional buildup& draw down test.
- Special test (pulse, interference, falloff).

One of the major tools used to characterize petroleum reservoirs is well test analysis. The monographs by Matthews and Russell (1967) And Earlougher (1977) and the text book by Lee (1982) have reviewed pressure transient theory and application for many reservoir and testing conditions. Of the many publications in this field, only a few have considered multiphase flow theory and only one, Nygcird (1982), studied the possibility of estimating relative permeability curves from well test data. The few publications reported on multiphase flow can be divided into two main categories. First is the pressure approach by Penine (1956). Second is the pseudo pressure approach by Raghavan (1976). These approaches and their related Literature are reviewed flowers:

$$k_i = \frac{162.6 q_i \mu B}{m^* h} \qquad (2.47)$$

The solution for total system mobility, λt, has been applied by Fetkovich and vienot(1984) as well as Raghavan (l986). May be written as:

$$\lambda_t = (\frac{k}{u})_t = \frac{162.6q_t}{m^*h} \tag{2.48}$$

Where:

$$q_t = q_oB_o + [q_g - q_oR_s + q_wR_{sw}]B_g + q_wB_w \tag{2.49}$$

And m^* is the slope of the semi log straight line in the p versus $\log t$ or $\log \frac{\Delta t + t_p}{\Delta t}$ plot.

The solution for wellbore skin, based on Penine's approach, may be written as:

$$S = 1.151[\frac{P_{1hr} - P_i}{m^*} - log\left(\frac{\lambda_t}{\emptyset C_t r_w^2}\right) + 3.23] \tag{2.50}$$

Martin derived this equation assuming negligible pressure and saturation gradients. The total compressibility - mobility ratio was assumed constant with pressure to linear size.

2.15. Permeability from wire line logging:

RFT is an open-hole wire line tool that provides accurate down-hole measurements of formation pressure. This pressure information can be analyzed to estimate k. also permeability can be calculated from resistivity log result (water saturation).

2.16. Permeability estimates based on production data:

❖ The methods based on analysis of production data measure permeability in a total drainage area.

❖ Analytical techniques (type-curve analysis)

❖ Reservoir simulation methods.

Methods based on analysis of production data involve matching the observed well performance given the flowing pressure history.

Analytical techniques (type-curve analyses) generate production forecasts using analytical, single-phase solutions for assumed reservoir geometries. Reservoir simulation methods may be necessary when complex reservoir geometries are Reservoir apparent or when multi-phase flow of fluids occurs.

Chapter Three:

Methodology

Input data should be prepared prior to be used to in simulators, we create a computer program by using visual studio to normalize, averaging and denormalize the relative permeability data, it is helpful to set up the calculation steps for each core sample and show the methods which have been used.

3.1. Normalization and averaging steps:

The following normalization and averaging step describes the necessary steps for a water-oil system.

Step 1: Select a values of S_w starting at S_{wc} and S_{oc}, list the corresponding values of k_{ro} and k_{rw}.

Step 2: Calculate the normalized water saturation S^*_w and S^*_o for each set of relative permeability curves and list the calculated values by using the following expression:

$$s^*_w = \frac{S_w - S_{wc}}{1 - S_{wc} - S_{oc}} \qquad\qquad (3.1)$$

$$S^*_o = 1 - S^*_w \qquad\qquad (3.2)$$

Where:-

S_{oc}=Critical Oil Saturation.

S_{wc}= Connate-water Saturation.

S^*_w=Normalized Water Saturation.

S^*_o=Normalized Oil Saturation.

Step 3: Calculate the Water, Oil relative permeability exponent by using the following expression:

$$m = \frac{\log(k_{rw}) - \log(k_{rw})_{end\,point}}{\log(S_w^*)} \tag{3.3}$$

$$n = \frac{\log(k_{ro})}{\log(S_o^*)} \tag{3.4}$$

Where:

m= Water relative permeability exponent.

n = Oil relative permeability exponent.

Step 4: Calculate the averaging to Water, Oil relative permeability exponent m, n for each sample, by using the following expression:

$$m = \frac{\sum_{i=1}^{n} m_i}{\sum_{i=1}^{n} m} \tag{3.5}$$

$$n = \frac{\sum_{i=1}^{n} n_i}{\sum_{i=1}^{n} n} \tag{3.6}$$

Where:

m = Average water relative permeability exponent.

n = Average oil relative permeability exponent.

Step 5: calculate modified water, oil relative permeability by using the following expression:

$$mod\,k_{ro} = (S_o^*)^{n\,avg} \tag{3.7}$$

$$mod\,k_{rw} = (S_w^*)^{m\,avg} * k_{rw_{(end\,point)}} \tag{3.8}$$

Step 6: Calculate the normalized relative permeability values for the oil and water as a function of the normalized water saturation by select arbitrary values of S_w by applying the following relationships:

$$K_{ro}^* = (1 - S_w)^{n\ avg} \qquad\qquad (3.9)$$

$$K_{rw}^* = (S_w)^{m\ avg} \qquad\qquad (3.10)$$

Where:-

K_o=Relative permeability of oil at different S_w.

K_o^* = Normalized relative permeability of oil.

K_w=Relative permeability of water at different S_w.

K_w^* = Normalized relative permeability of water.

Step 7: Using regular Cartesian coordinates, plot the normalized k_{ro}^* and k_{rw}^* versus S_w for all core samples on the same graph.

Step 8: Determine the average normalized relative permeability values for oil and water as a function of the normalized water saturation by select arbitrary values of S_w^* and calculate the average of k_{ro}^* and k_{rw}^* by applying the following relationships:

$$(K_{ro}^*)_{avg} = \frac{\sum_{i=1}^{n}(h\,k\,k_{ro}^*)_i}{\sum_{i=1}^{n}(h\,k)_i} \qquad\qquad (3.11)$$

$$(K_{rw}^*)_{avg} = \frac{\sum_{i=1}^{n}(hkk_{rw}^*)_i}{\sum_{i=1}^{n}(hk)_i} \qquad\qquad (3.12)$$

Where:

n= Total number of core samples i.

h_i = Thickness of sample i.

k_i = Absolute permeability of sample i.

Step 9: Using regular Cartesian coordinates, plot the normalized $(k_{ro}^*)_{avg}$ and $(k_{rw}^*)_{avg}$ versus S_w.

3.2. Denormalization steps:

Step 1: The last step in this methodology involves denormalizing the average curve to reflect actual reservoir and conditions of S_{wc} and S_{oc}. These parameters are the most critical part of the methodology and, therefore, a major effort should be spent in determining representative values.

We calculate water saturation S_w, oil relative permeability k_{ro} and water relative permeability k_{rw} by the following expression:

$$(S_w) = S_{wc} + S_w * (1 - S_{wc} - S_{co}) \tag{3.13}$$

$$k_{ro} = (k_{ro}^*) * k_{ro(swc)} \tag{3.14}$$

$$k_{rw} = (k_{rw}^*) * k_{rw(sor)} \tag{3.15}$$

Where:

(S_w) = Denormlized water saturation.

S_{wc} = Averaging of critical water saturation.

S_{oc} = Averaging of critical oil saturation.

S_w = Normalized water saturation that selected arbitrary values.

k_{ro} = Denormlized oil relative permeability.

k_{rw} = Denormlized water relative permeability.

k_{ro}^* = Averaging of oil relative permeability.

k_{rw}^* = Averaging of water relative permeability.

Step 2: plot the denormalized k_{ro} and k_{rw} versus (S_w).

3.3. Calculation methods:

3.3.1 Excel method:

Table (3.1): Raw data requirements to start calculation.

WATER-OIL RELATIVE PERMEABILITY, STEADY STATE AT OVERBURDEN PRESSURE OF 5450 PSIG											
sample 1			sample 2			sample 3			sample 4		
DEPTH(m) :			DEPTH(m) :			DEPTH(m) :			DEPTH(m) :		
POROSITY(%) :			POROSITY(%) :			POROSITY(%) :			POROSITY(%) :		
GAS PERMEABILITY (mD) :			GAS PERMEABILITY (mD) :			GAS PERMEABILITY (mD) :			GAS PERMEABILITY (mD) :		
Ko @ Swi =			Ko @ Swi =			Ko @ Swi =			Ko @ Swi =		
Kw @ Sor =			Kw @ Sor =			Kw @ Sor =			Kw @ Sor =		
swi = , sor =			swi = , sor =			swi = , sor =			swi = , sor =		
Sw	Kro	Krw	Sw	Kro	Krw	Sw	Kro	Krw	Sw	Kro	Krw

Table (3.2): Modified data table.

		MODIFIED						
sample 1		sample 2		sample 3		sample 4		
sw*	so*	m	mavg	n	avg	mod kro	mod krw	krwn

Table (3.3): Normalize data table.

	NORMALIZATION							
	sample 1		sample 2		sample 3		sample 4	
Sw	kro*	krw*	kro*	krw*	kro*	krw*	kro*	krw*

Table (3.4): Average and denormalize data table.

AVERAGING	
kroavg	krwavg

DENORMALIZED		
sw	kro	krw

3.3.2 RPNP program method:

Relative Permeability normalization program (RPNP) is our computer program to do the normalization, averaging and denormalization for relative permeability to be in simulator format. It's easy and simple for using.

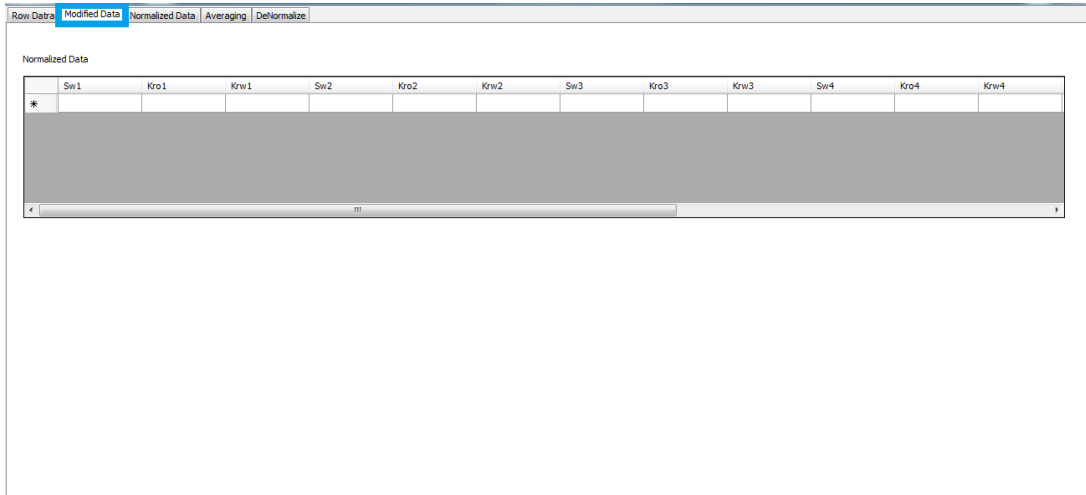Below are screenshots from our computer program describing the steps of how to use it?
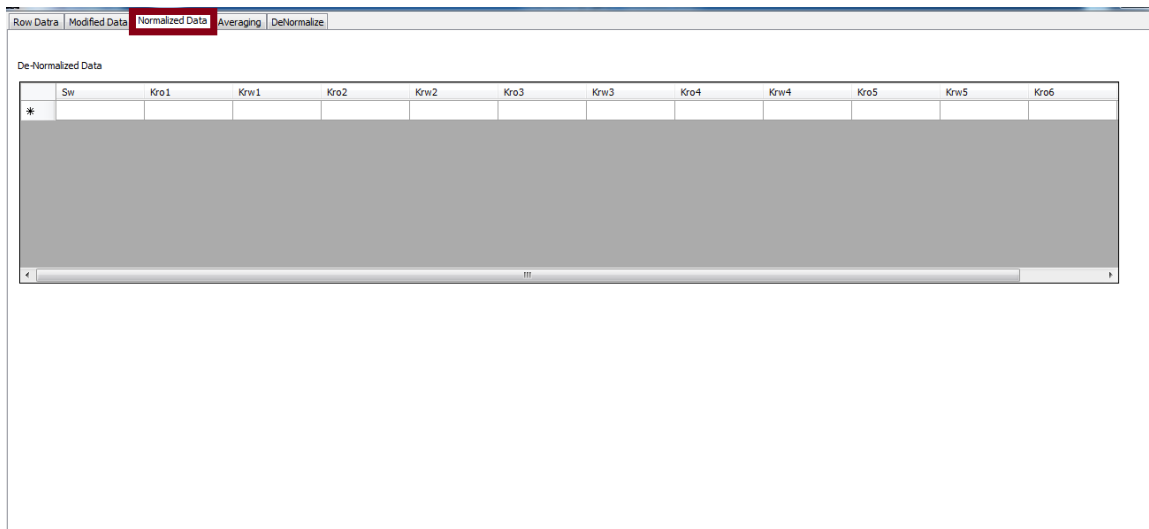
- **Step 1:**

Figure(3. 1): program data input interface.
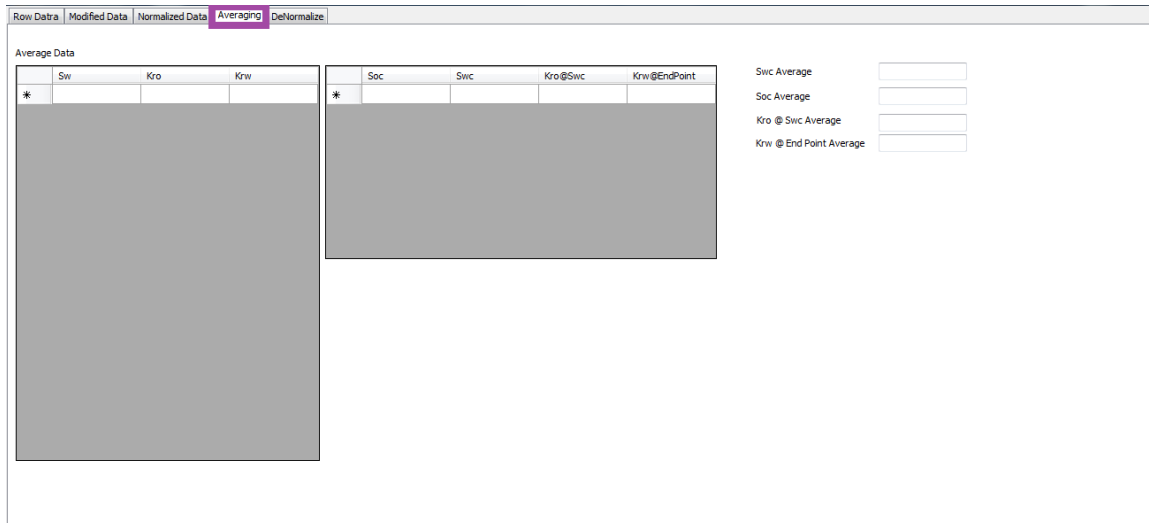
- **Step2:**

Figure(3. 2): computer program modifiding process
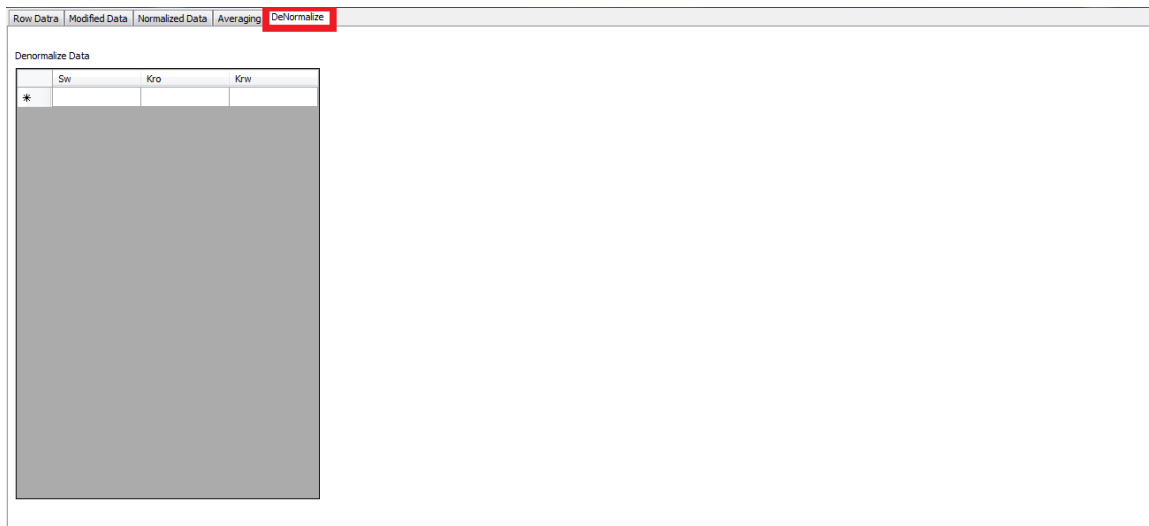
- **Step 3:**

Figure(3. 3): computer program normalizing process.

- **Step 4:**

Figure(3. 4): computer program averaging process

- **Step 5:**

Figure(3. 5): Our computer program denormalizing process

Chapter Four:

Results

4.1. Results:

In this research, we applied mathematical procedures to calculate and prepare relative permeability data to be used in simulators. This procedures are known as normalization averaging and de-normalization and they have been applied on relative permeability data given from samples extracted from X sand stone reservoir. These samples have the following properties:

Table (4.1): Raw data for samples 1, 2, 3 and 4

WATER-OIL RELATIVE PERMEABILITY, STEADY STATE AT OVERBURDEN PRESSURE OF 5450 PSIG											
sample 1			sample 2			sample 3			sample 4		
DEPTH(m) : 1175.1			DEPTH(m) : 1276.45			DEPTH(m) : 1317.89			DEPTH(m) : 1320.35		
POROSITY(%) : 33.5			POROSITY(%) : 31.6			POROSITY(%) : 32.1			POROSITY(%) : 30.3		
GAS PERMEABILITY (mD) : 2033			GAS PERMEABILITY (mD) : 994			GAS PERMEABILITY (mD) : 4051			GAS PERMEABILITY (mD) : 4871		
Ko @ Swi = 658 mD			Ko @ Swi = 295 mD			Ko @ Swi = 1264 mD			Ko @ Swi = 1564 mD		
Kw @ Sor = 338 mD			Kw @ Sor =184 mD			Kw @ Sor = 719 mD			Kw @ Sor = 971 mD		
swi = 15.3(%ps) , sor =34.5(%ps)			swi = 19.40(%ps) , sor =32.70(%ps)			swi = 12.9(%ps) , sor =34.1(%ps)			swi = 9.0(%ps) , sor =40.6(%ps)		
Sw	Kro	Krw	Sw	Kro	Krw	Sw	Kro	Krw	Sw	Kro	Krw
0.153	1.00000	0.000	0.194	1.00000	0.000	0.129	1.00000	0.000	0.090	1.00000	0.000
0.313	0.25527	0.036	0.384	0.20184	0.063	0.313	0.20184	0.050	0.200	0.41210	0.027
0.360	0.17539	0.059	0.453	0.11695	0.119	0.428	0.09247	0.166	0.279	0.28642	0.080
0.388	0.13490	0.074	0.505	0.06383	0.181	0.476	0.04667	0.245	0.357	0.17298	0.163
0.414	0.11402	0.091	0.537	0.03917	0.229	0.513	0.03221	0.299	0.409	0.11995	0.231
0.427	0.09817	0.101	0.560	0.02500	0.278	0.537	0.02183	0.327	0.447	0.07278	0.301
0.451	0.07413	0.116	0.577	0.01726	0.308	0.553	0.01660	0.358	0.464	0.05559	0.333
0.484	0.05395	0.150	0.600	0.01102	0.375	0.566	0.01191	0.401	0.480	0.04009	0.366
0.510	0.03707	0.178	0.617	0.00649	0.429	0.588	0.00822	0.430	0.497	0.02673	0.406
0.531	0.02904	0.214	0.637	0.00458	0.490	0.600	0.00536	0.449	0.513	0.01652	0.438
0.555	0.01722	0.258	0.646	0.00329	0.527	0.614	0.00362	0.470	0.527	0.01000	0.468
0.580	0.00964	0.310	0.654	0.00210	0.560	0.625	0.00231	0.489	0.539	0.00594	0.500
0.591	0.00650	0.338	0.662	0.00126	0.585	0.637	0.00134	0.511	0.550	0.00321	0.535
0.612	0.0040	0.385	0.668	0.0007	0.614	0.644	0.0007	0.530	0.560	0.0021	0.558
0.627	0.0022	0.425	0.673	-	0.624	0.648	0.0005	0.542	0.571	0.0010	0.583
0.637	0.0013	0.450				0.655	0.0003	0.557	0.581	0.0005	0.601
0.642	0.0008	0.470				0.659	-	0.569	0.588	0.0003	0.615
0.650	0.0005	0.491							0.594	-	0.621
0.655	-	0.514									

4.1.1. Calculation Methods Applied:

- Excel program method.
- RPNP computer program method.

4.1.1.1. Excel program method:

Here by using regular Cartesian coordinates, we plot the k_{ro} and k_{rw} versus S_w for all core samples on the same graph, to check core sample's data.
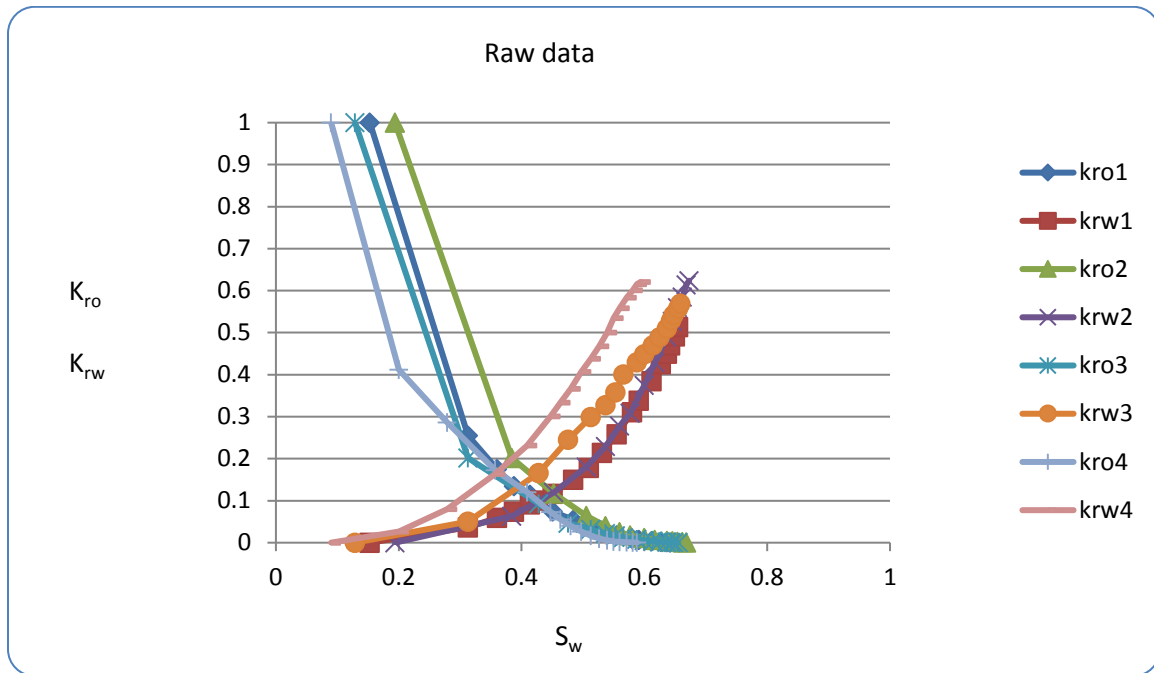

Figure (4.1): S_w Vs K_{ro}, K_{rw} for all samples.

In this **step,** we calculated S_w^* and did the modified step to correct K_{ro} and K_{rw} by calculating m and n by equations (3.1), (3.2), (3.3), (3.4), (3.5), (3.6), (3.7) and (3.8) presented on chapter 3 then plotting S_w^* Vs modified K_{ro} and K_{rw}
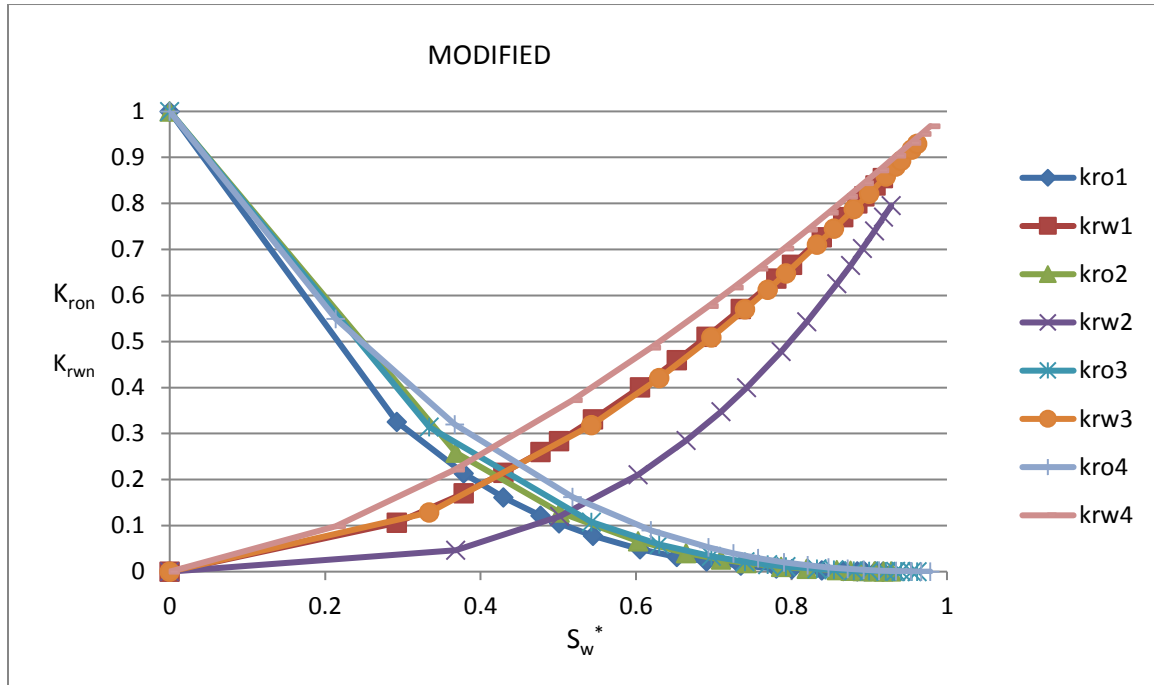

Figure (4.2): S_w^* Vs K_{ron}, K_{rwn}

In this **step**, we select arbitrary values of S_w and calculate K_{ro}^* and K_{rw}^* by using equation (3.9) and (3.10) presented in chapter 3 and plotting S_w Vs K_{ro}^* and K_{rw}^*

Table (4.2): Normalize data for samples 1, 2, 3 and 4.

| BI	BJ	BK	BL	BM	BN	BO	BP	BQ	BR	BS	BT	BU	BV
						Normalization							
		sample 1			sample 2			sample 3			sample 4		
	Sw	kro*	krw*		kro*	krw*		kro*	krw*		kro*	krw*	
	0	1	0		1	0		1	0		1	0	
	0.05	0.846537	0.004121		0.859732	0.0001		0.864145	0.003672		0.879931	0.011107	
	0.1	0.710198	0.014685		0.733123	0.000843		0.740874	0.013437		0.768941	0.031462	
	0.15	0.589864	0.030879		0.61949	0.002932		0.629623	0.0287		0.666791	0.057852	
	0.2	0.484435	0.052323		0.518152	0.007101		0.529823	0.049174		0.573234	0.089125	
	0.25	0.392824	0.078766		0.428421	0.014099		0.440903	0.074666		0.488018	0.124618	
	0.3	0.313962	0.110025		0.349611	0.024695		0.362283	0.105033		0.410881	0.16388	
	0.35	0.246797	0.145953		0.28103	0.039666		0.293379	0.140162		0.341551	0.206583	
	0.4	0.190297	0.186432		0.221987	0.059798		0.233601	0.179959		0.279749	0.25247	
	0.45	0.143448	0.231361		0.171785	0.085889		0.182349	0.224345		0.225182	0.301337	
	0.5	0.105257	0.280653		0.129724	0.118741		0.139018	0.273251		0.177546	0.353012	
	0.55	0.074753	0.334232		0.095104	0.159165		0.102995	0.326615		0.136523	0.407352	
	0.6	0.05099	0.392031		0.067217	0.207976		0.073655	0.384384		0.101776	0.464234	
	0.65	0.033047	0.453988		0.045353	0.265996		0.050364	0.446508		0.07295	0.523548	
	0.7	0.02003	0.520048		0.028797	0.334052		0.032475	0.512944		0.049668	0.585201	
	0.75	0.011079	0.59016		0.016828	0.412976		0.019326	0.583649		0.031523	0.649106	
	0.8	0.005367	0.664279		0.00872	0.503603		0.010239	0.658587		0.01807	0.715189	
	0.85	0.002108	0.742361		0.003736	0.606773		0.004515	0.737723		0.008818	0.78338	
	0.9	0.000565	0.824366		0.001131	0.72333		0.001423	0.821023		0.003208	0.853616	
	0.95	5.95E-05	0.910257		0.000147	0.854122		0.000198	0.908459		0.00057	0.925841	
	1	0	1		0	1		0	1		0	1	
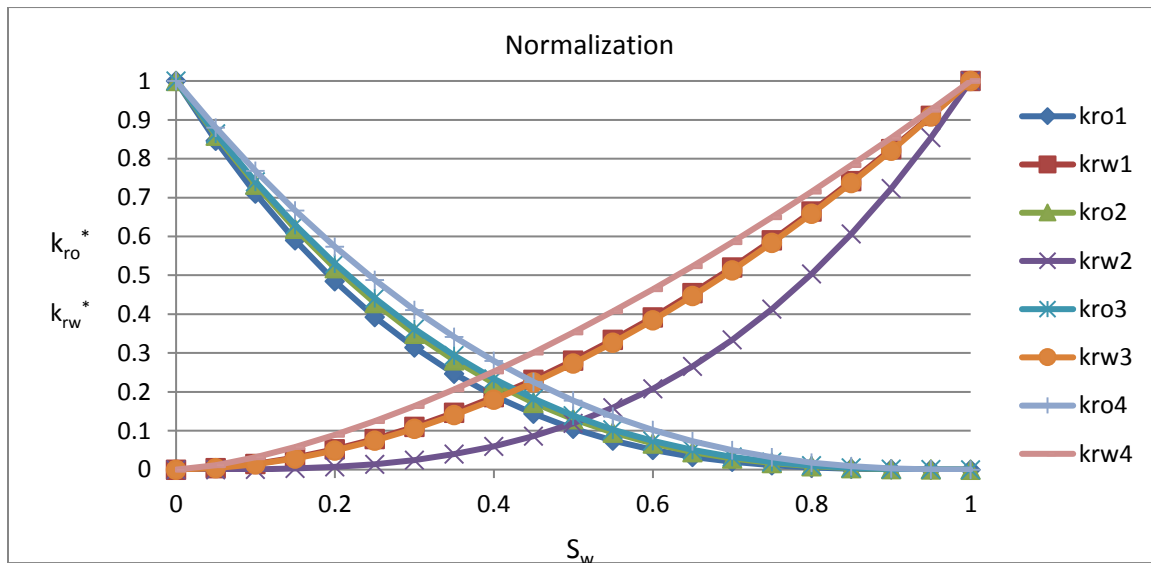
Figure (4.3): Assumed S_w Vs K_{ro}^*, K_{rw}^*

Then doing the averaging step for all samples by equation (3.11) and (3.12) presented in chapter 3. And plotting S_w Vs $K_{ro\ (avg)}$ and $K_{rw\ (avg)}$.

Table (4.3): Average data table.

| Avarging	
kroavg	krwavg
1	0
0.8625864	0.00475
0.7382838	0.015107
0.6264419	0.030091
0.526411	0.049431
0.4375415	0.073037
0.3591841	0.100908
0.2906896	0.133091
0.2314085	0.169665
0.180691	0.210733
0.1378866	0.256414
0.1023438	0.306841
0.0734095	0.362156
0.0504285	0.42251
0.0327426	0.488061
0.0196891	0.558973
0.010599	0.635414
0.0047943	0.717559
0.0015819	0.805584
0.0002434	0.89967
0	1
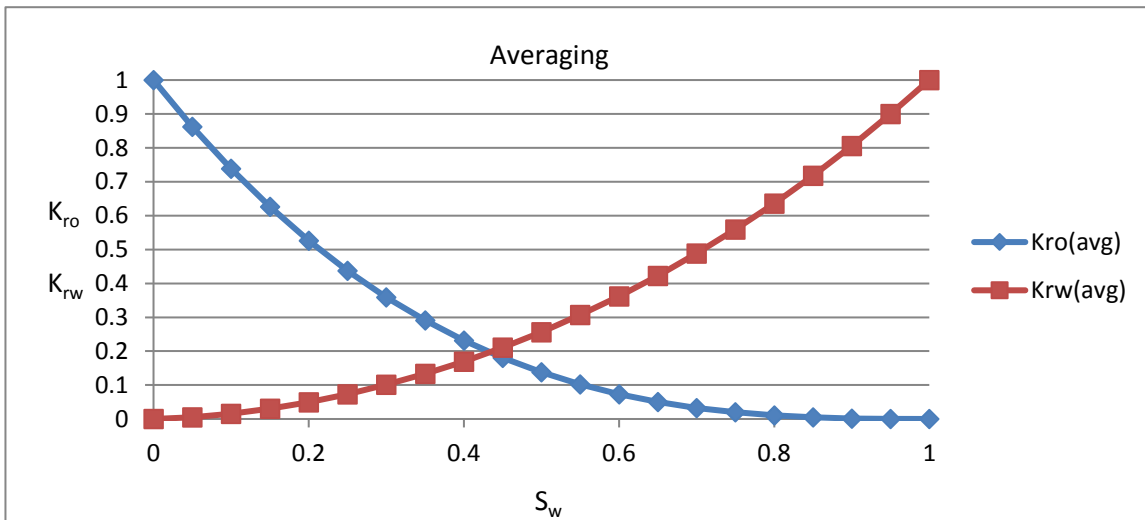
Figure (4.4): Assumed S_w Vs $(K_{ro}, K_{rw})_{avg}$.

Here is the last step which called de-normalization, in this step we return the relative permeability's curve to its normal situation from S_{wi} to S_{or} and then calculated by equations (3.13), (3.14) and (3.15) which were presented in chapter 3, also the average of K_{rw} and K_{ro} at S_{oc} and S_{wc} have been calculated respectively and get the final plot as below Figure (4.5).

Table (4.4): Denormalize data table.

| BZ	CA	CB
krw@soc	0.5817699	
kro@swc	1	
swc	0.1415	
soc	0.34875	
DENORMALIZED		
sw	kro	krw
0.1415	1	0
0.16699	0.8625864	0.002763
0.19248	0.7382838	0.008788
0.21796	0.6264419	0.017504
0.24345	0.526411	0.028754
0.26894	0.4375415	0.042486
0.29443	0.3591841	0.058698
0.31991	0.2906896	0.077419
0.3454	0.2314085	0.098694
0.37089	0.180691	0.122583
0.39638	0.1378866	0.149156
0.42186	0.1023438	0.178489
0.44735	0.0734095	0.210666
0.47284	0.0504285	0.245774
0.49833	0.0327426	0.283905
0.52381	0.0196891	0.325154
0.5493	0.010599	0.369621
0.57479	0.0047943	0.417404
0.60028	0.0015819	0.468608
0.62576	0.0002434	0.523338
0.65125	0	0.5817
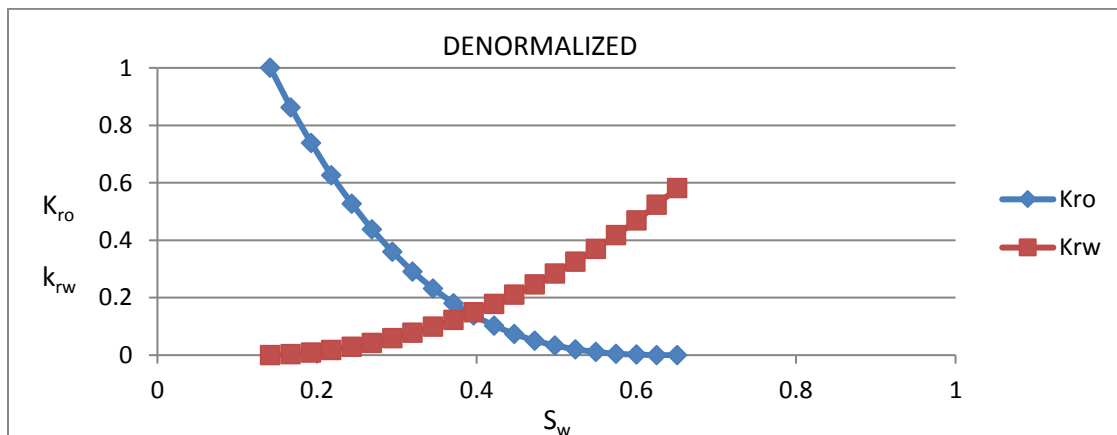
Figure (4.5): S_w Vs K_{ro}, K_{rw}

✓ From this plot, we noted that the reservoir is oil wet due to the intersection point between the k_{ro} and k_{rw} curves is less than 0.5.

4.1.1.2 RPNP computer program method:

Here we will show how RPNP program work, how it's simple and easy. The output was compared with Excel program method, so we get same results. The input data for the 4 samples were entered and plotted in the same graph.
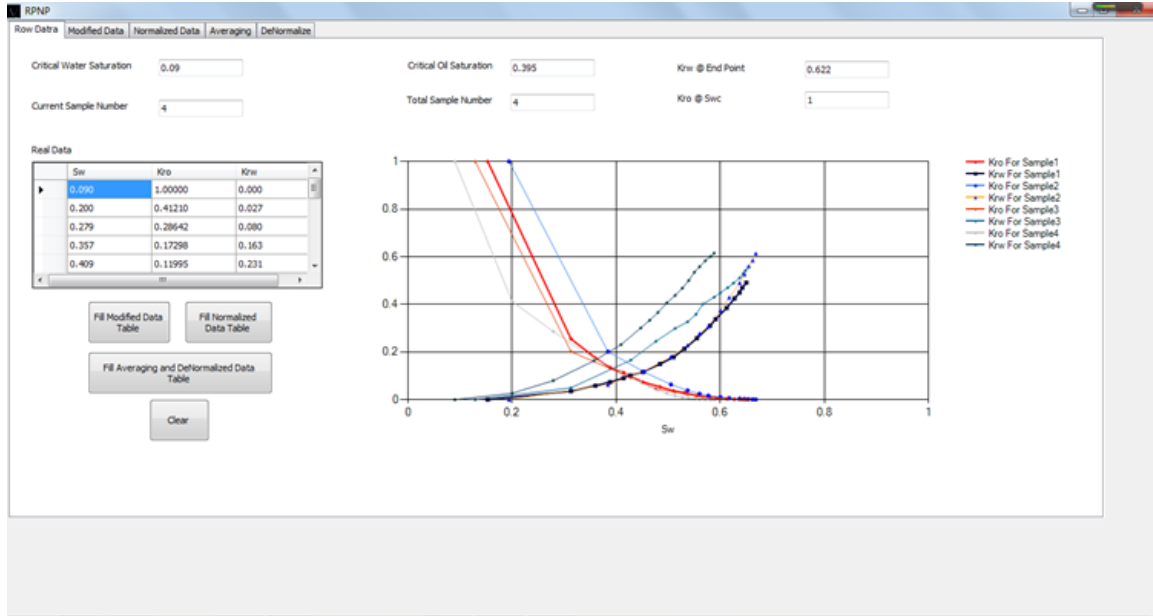

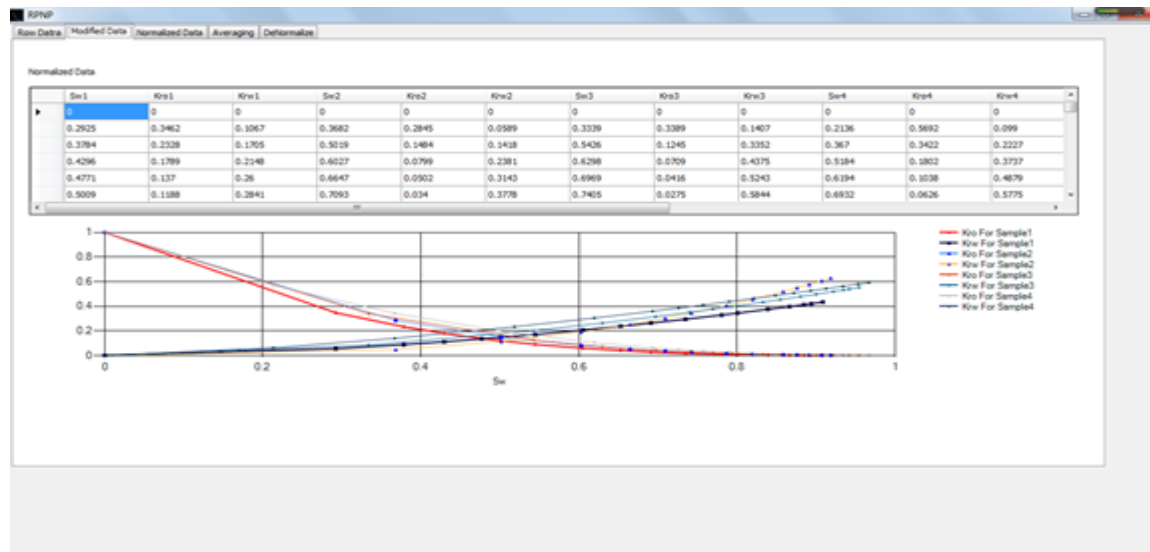**Figure (4.6):** Input data screen and raw data graph.

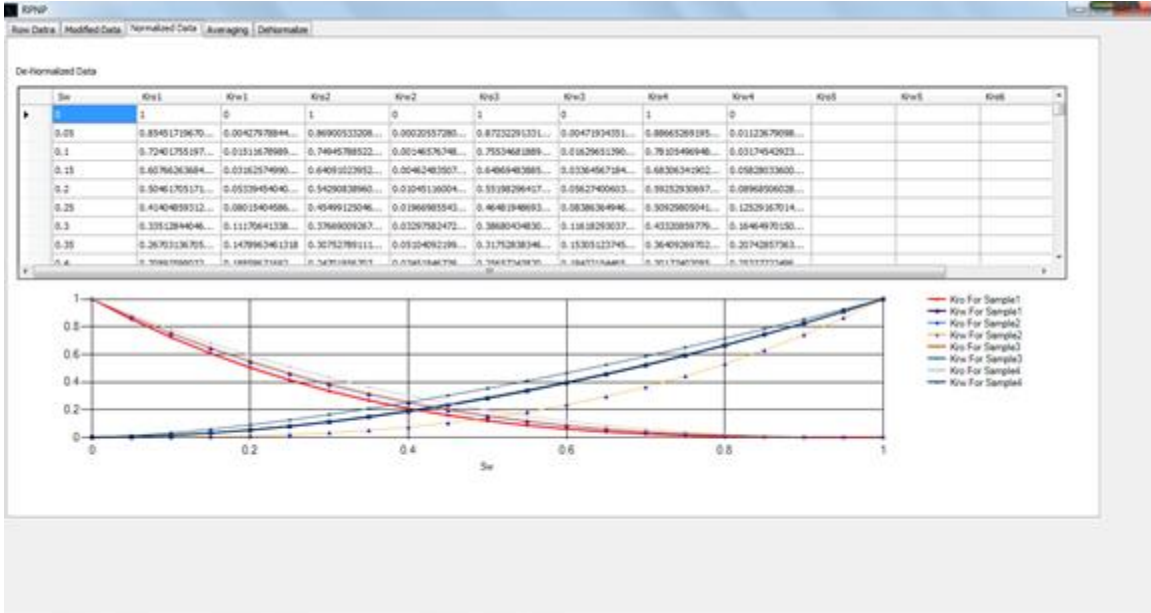

Figure (4.7): Modified data screen and its plot.

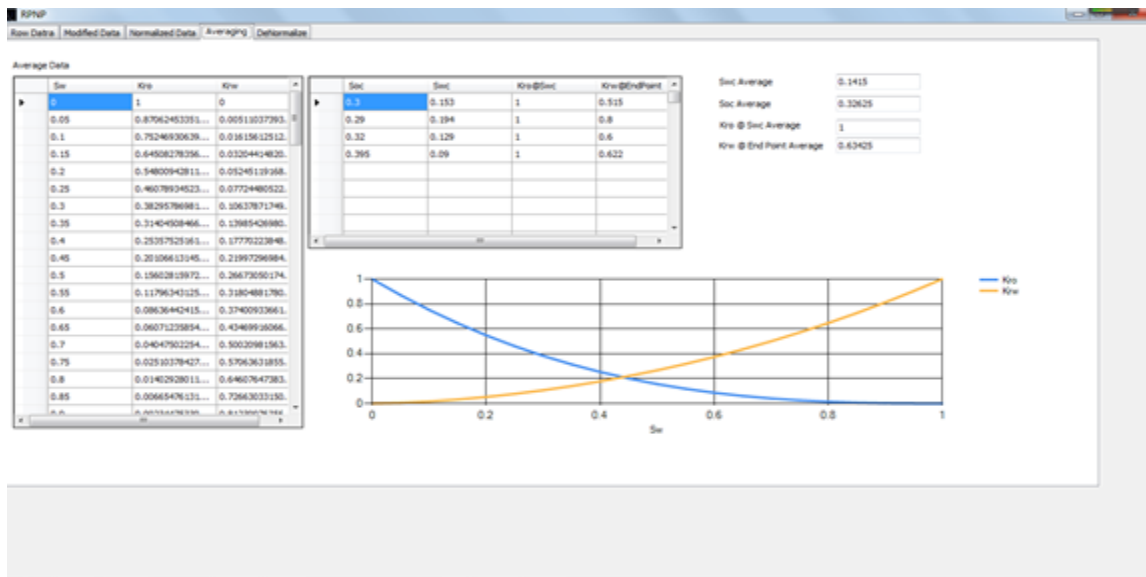**Figure (4.8):** Normalized data screen and its plot.

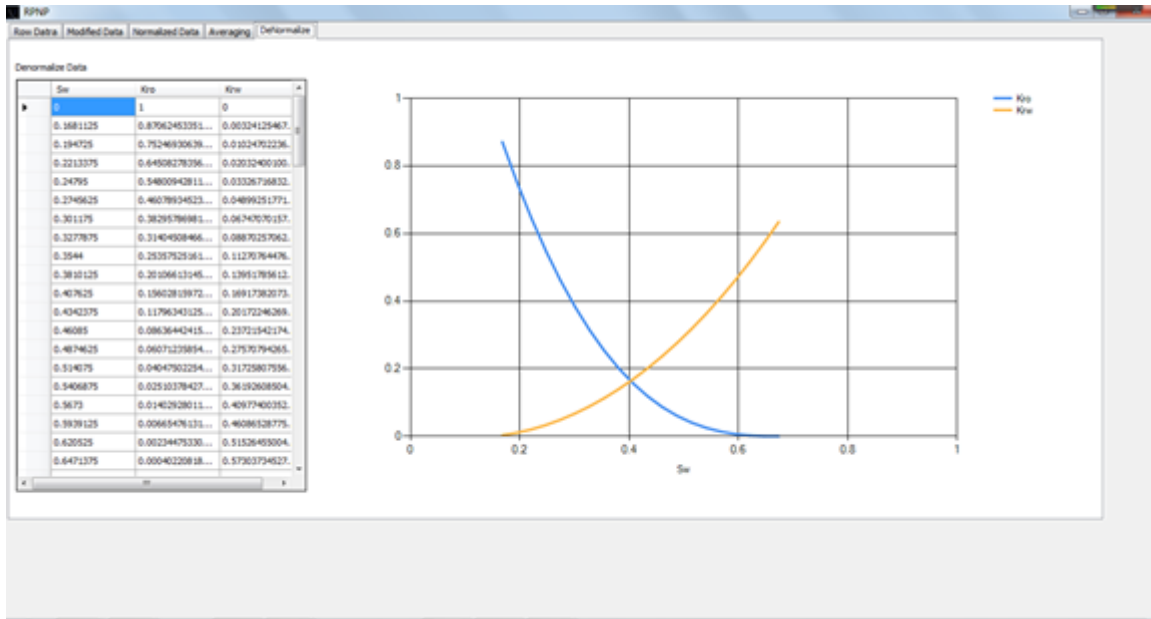**Figure (4.9):** RPNP computer program averaged data screen and its plot.

Figure (4.10): RPNP computer program normalized data screen and its plot.

✓ We got the normalized, modified, averaging and de-normized data in one click.

Chapter Five:

Conclusion & Recommendations

5.1. Conclusion:

Relative permeability normalization, averaging and de-normalization by using RPNP computer program can be computed in few minutes, even for large number of input data in one click, in contrast by using Excel program method it will take long time.

5.2. Recommendation:

We recommend to:

- extend the program to prepare:
  1- J function calculation.
  2- Pc calculation.
  3- Wettability.
- Develop the program to be useable for large number of samples.
- Develop the Software to include different normalization, averaging and de normalization methods.
- Update the computer program to have the ability to read S_{wc}, S_{oc}, $K_{ro}@S_{wc}$ and $k_{rw}@S_{or}$ from the raw data table in the input section.

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