ANDERSON CASTRO DE MELO JUNIOR

GUIDELINES FOR PERMEABILITY CURVES MEASUREMENTS AND MODELING

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AKNOLOGMENT

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to my family, especially my father and mother who, through many personal sacrifices, have given me the opportunity to fulfill my biggest and most ambitious dreams.

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Finally, to all those who will make use of this work, I hope it will be useful.

ABSTRACT

The debate on the energy transition and on methods of mitigating the effects of climate change have been the focus of many researches in recent years. One of the main methods studied to reduce the emission of greenhouse effect gases is the geological storage of CO_2 through the injection of this gas in oil reservoirs as an enhanced oil recovery method, in depleted reservoirs, or in deep saline aquifers.

Relative permeability is one of the main factors that dictate multiphase flow in a porous medium, being a parameter capable of describing the relative proportion of relative flows during the displacement of fluids in situ. Thus, the accurate characterization of relative permeability is essential for understanding and modeling of the phenomena that occur during the production of hydrocarbons and the injection of CO_2 into aquifers.

Permeability curves have been the focus of different lines of research from public and private investments in distinct parts of the world, in a way that literary production is remarkably diverse and diffuse. Authors used different methods, starting from different hypotheses and making it difficult to compare and define which method to use in each situation.

Through a systematic review of the literature, the objective of this work is to unify the information disseminated in papers published over decades and to compare the different findings so as to create general guidelines for the choice of methods and models to determine the permeability curves according to the different reservoir and aquifer conditions were they have to be applied.

Keywords: Permeability Curves, Relative Permeability, Enhanced Oil Recovery, CO_2 Injection, Reservoir Simulation.

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LIST OF SYMBOLS

p	pressure
g	gravity
ρ	density
Q, q	mass flow
A	area
μ	dynamic viscosity
μ_w	dynamic viscosity of water
μ_o	dynamic viscosity of oil
Re	Reynolds Number
L	length
H, h	height
w	width
k, k_∞	absolute permeability
k_o	effective permeability of oil
k_w	effective permeability of water
k_r	relative permeability
k_{ro}	relative permeability of oil
k_{rw}	relative permeability of water
k_{rg}	relative permeability of gas

k_{rwt}	wetting phase relative permeability
k_{rn}	non-wetting phase relative permeability
$k_{rg(Sorg)}$	gas relative permeability at the residual oil saturation
ϕ	porosity
c_t	total compressibility
t	time
S_w	saturation of water
S_o	saturation of oil
S_g	saturation of gas
S_{iw}	initial water saturation
S_{w^*}	normalized wetting phase saturation value
S_m	1 minus the residual oil saturation
S_{org}	residual oil saturation in oil and gas systems
S_{orw}	residual oil saturation in oil and water systems
S_{wi}	irreducible water saturation
S_{gc}	critical gas saturation
p_c	capillarity pressure
$p_{c,th}$	capillarity threshold pressure
θ	wetting angle
σ	interfacial tension
r	interface radius

$\boldsymbol{f_x}$	fractional flow
$\boldsymbol{f_w}$	fractional flow of water
$\boldsymbol{f_o}$	fractional flow of oil
b	Klinkenberg factor
$\boldsymbol{\beta}$	coefficient of inertial strength
$\mathbf{I_r}$	Injectivity ratio
$\boldsymbol{\lambda}$	pore size distribution index

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1 INTRODUCTION

Global warming and climate change caused by the emission of greenhouse gasses led developed economies to adopt policies, especially from the end of the 20th century, to mitigate the effects of these changes. The Kyoto's Protocol, signed in 1997, recognized the responsibility of developed economies, and established a commitment by industrialized countries and economies in transition to limit and reduce greenhouse gas (GHG) emissions according to individual targets, establishing mitigation policies and measures and requiring periodic reports (UNFCCC, 1997).

In line with the spirit of sustainable development, in December 2015, 196 countries signed the "Paris Agreement" to limit global warming to 1.5 degrees Celsius, leading these countries to intensify their energy transition policies. The search for neutrality in the emission of GHG is a mark in which, for the first time, many nations committed to ambitious targets in the fight against climate change.

Carbon Capture and Storage (CCS) is a group of technologies that have the common objective of reducing greenhouse gas emissions into the atmosphere from the extraction, combustion, or use of fossil fuels or other carbon sources. The idea is to create a means by which it would be possible to harness large amounts of energy through affordable, portable, and dense fuels so that they can be used with minimal impact on the climate. The technology for exploring, refining, and using the fossil fuels is already well mastered, and their costs are relatively low compared to other energy sources. Even today, there is no global treaty that limits greenhouse gas emissions or penalizes those who do not respect the target emissions. In this way, there is no direct financial cost concerning climate effects for users and producers of components derived from fossil fuels. However, CCS technologies might compensate and mitigate the impact caused by carbon dioxide (CO_2) emissions. CCS is generally performed in 3 steps (Stuart et al., 2018):

- capture and purification of CO_2 from the burning of fuels, raw materials, and industrial emissions;
- compression of CO_2 and transport by pipeline or storage tank;

- CO_2 injection into geological reservoirs.

The development of these types of technologies has been the focus of massive investments both by government and private initiatives as well as of large research centers worldwide. A study published by Stuart et al. in 2018 shows an exponential trend for the coming years in CO_2 injection projects, highlighting the need to study the key petrophysical parameters that guide the flow of fluids in porous media, such as absolute and relative permeabilities, wettability, and interfacial tension.

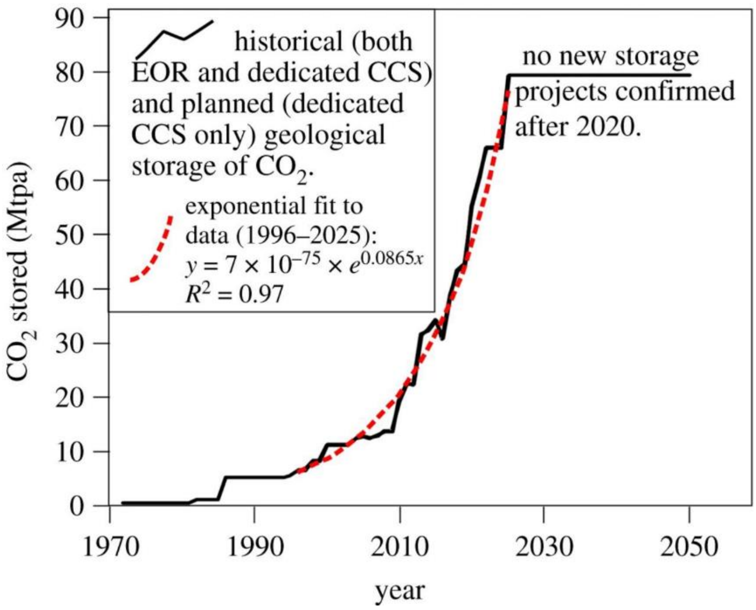

Figure 1.1-The evolution of the number of CO_2 geological injection projects. Source: Stuart et al (2018).

In general, hydrocarbon production operations promote recovery of less than 30% of the original oil in place (OOIP). This fact is due to two main factors: depletion of the reservoir and excessive production of water. Depletion occurs because the formation is depressurized when the reservoir fluids are produced. When production becomes unprofitable, it is decided to abandon the well, leaving a large part of the oil in the reservoir. During production, there is a three-phase flow producing water, oil and gas, nonetheless, the aqueous phase is unwanted, and the higher the produced water content (watercut) the higher the costs of corrosion prevention, water treatment for disposal or reinjection, and, logically, the smaller the volume of relative oil produced. In practice, the watercut tends to grow, being a decisive factor in the decision to abandon the well. The ratio between the volume of hydrocarbons produced during the entire life of the field and the volume of original hydrocarbons from the formation is called the recovery factor and a large part of the investments in research and development (R&D) in the oil and gas sector is focused on raising, at least by a few percentage points, this number. The final volume of oil to be recovered depends directly on several formation properties such as rock wettability, interfacial tension (IFT), pressure loss during the lifetime of the field and the relative permeability.

The permeability curves are one of the main components in the in numerical simulations of fluid flows in hydrocarbon-reservoirs. While absolute permeability depends almost exclusively on pore geometry, relative permeability is strongly influenced by physic-chemical interactions between fluids and between fluid and rock as highlighted in the previous sections, so the actual permeability curve can change point by point accordingly with the lithological changes of the rock. Generally, a representative base curve for the reservoir is used and empirical adaptations such as the so-called "end-point scaling" are used to adjust the curves according to the reservoir's production history, through the so-called "historical match", obtaining and validating a curve representative for production forecasting purposes.

The permeability of a porous medium can be determined from samples taken from the reservoir or by on-site tests such as well logging and well testing. The measurements of permeability curves are usually performed using core samples from the reservoir. The samples, once in the laboratory, can be cleaned, subjected to chemical aging treatments or kept in their natural state so that, through a pressure gradient, a flow of different phases can be produced through the porous medium to determine the permeability curves by different methods.

Even though the relative permeability curves have been the focus of different lines of research and investments in different parts of the world, and the literary production about permeability curves is very diverse and difuse. Authors use different methods, assuming different hypotheses, making it difficult to compare the methods and define which one is most efficient for each situation.

1.1 Objective

The objective of this work is to summerize the information that is now disseminated in tens of publications through a sistematic literature review and to propose general guidelines for carrying out measurements and models of permeability curves, comparing the different most used methods and models available in the literature and defining in which cases each method should be applied.

1.2 Motivation

The development of knowledge of multiphase flow in porous media is fundamental for the planning of projects in the energy sector, being particularly important in carbon storage projects and in oil production projects. As pointed out, relative permeability curves play a decisive role in the flow of fluids present in the system studied, so that their understanding is fundamental for the creation of models capable of describing the phenomena involved in the displacement of these fluids, serving as input for numerical models. and being fundamental for the planning of projects in the oil sector and of carbon capture projects.

Thus, considering the importance of the energy transition for the modern world, the evident growth in the number of projects involving the modeling of the relative permeability of fluids and the urgent need for the development of efficient methods of containment and storage of carbon dioxide, as well as the variety of methods and models described in the literature, it becomes evident the importance of carrying out an analysis of the available material in order to compare and organize them according to their applicability.

1.3 Methodology

To achieve the initial target of this work, an initial systematic review of the existing literature was necessary. Conforto et al (2011) defines a literature review as a scientific research method to search and analyze sources from a determined area of science that allows other authors to use the work as a reliable source of results.

Such systematization of literary review is something widely adopted in human and medical sciences, but not so commonly found in works related to exact areas. Conforto et al (2011) built a literature review guide for project management, the methodology adopted in this work is an adaptation of the author's proposal. The idea is to define a strategy and a systematic method for searching for sources and analyze relevant results, creating a constructive algorithm capable of creating a linear narrative between the studied themes, approaching the theoretical and experimental bases when necessary. The method adopted in this work can be described in 3 stages in which the same cycle was repeated. The methodological cycle can be described being schematized by the Figure 1.2:

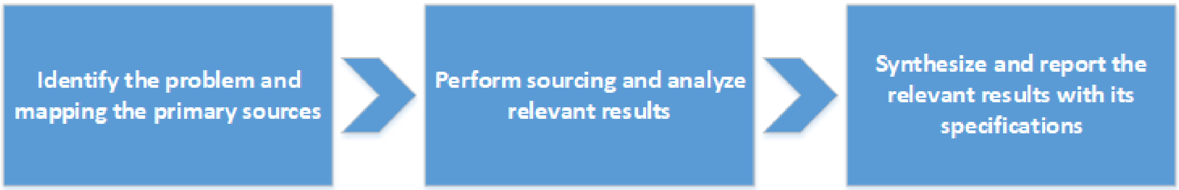

Figure 1.2- Cycles adopted per revision stage.

The first step of the cycle was dedicated to identifying the main problems related to the initial objective of the work of each phase and to mapping the primary sources capable of providing the theoretical framework for a good understanding of the problem. The primary sources consist of the main articles, books, journals, or databases relevant to the definition of study topics at each stage, they are usually cited by several authors. The criteria for selecting the primary sources were the consistency of the methods adopted, the relevance of journals, and publishers given by notorious knowledge, the number of citations and, finally, the alignment with the scope of this study.

The second step was structured in order to initially list the studies found in the literature according to the relevant keywords for the topic studied in each stage and perform the filtering again according to the selection criteria adopted in step 1: evaluating the consistency of the methods adopted through a critical reading, the relevance of journals, journals and publishers given by notorious knowledge, the number of citations and finally the alignment and relevance of the methods and results for the topic studied at each stage.

The third and last step of each cycle consisted of identifying the relevant topics for this work and reporting the results and theoretical developments in a synthetic way, specifying the main hypotheses and constrains adopted.

This work has been divided into three main stages according to its organization:

- Theoretical basis of the basic topics for permeability curves and their applications, in which the main theoretical bases necessary for the real understanding of the problem and the proposed work were identified, as well as discussions of the relevance of each topic presented, based on the literature, in the results of the permeability curves.
- Review of experimental methods for measuring permeability curves, in which the experimental methods were described as well as the theory behind these experiments, discussing their limitations and practical applications.
- Review of empirical and numerical models of permeability curves available in the literature, promoting the discussion of their adopted methodologies, as well as their main limitations and practical applications.

So that at each stage of the work, a cycle like the one described in Figure 1.2 was performed so that the first stage of this work provides the necessary basis for a good understanding of the following, creating a didactic narrative linearity to help the understanding of the reader. Through this organization it was possible to fulfill the objectives initially listed in the work.

2 BASIC CONCEPTS

2.1 Fluid Mechanics in Porous Media

The modeling and mathematical description of traditional fluid mechanics problems was the exclusive focus of many authors, mainly due to the need to better describe hydraulic circuits. The greatest advance on this topic was made by Daniel Bernoulli, in his magnum opus “Hydrodynamics", originally published in 1739 (Oliveira, 2019), in which he formulates the well-known Bernoulli equation:

$$p + \frac{\rho v^2}{2} + \rho g H = Constant \qquad \text{(Eq 2.1.1)}$$

Where p is the pressure at a given point, ρ is the density of the given fluid, v is the velocity of the infinitesimal element, g is gravity and H is the height relative to an adopted reference system.

With the development of pipeline transport, especially from the 19th century onwards, it was necessary to develop a series of correlations to consider the loss and dissipation of energy due to the viscosity of the fluids and even the existing friction through graphical methods (Moody's diagram) or numerical (Colebrook–White equation) (Menon, 2015).

However, these classical approaches start from the assumption that the flow is stable and given in a continuous and incompressible fluid. So, as it does not accurately describe fluid flow in porous media, it is necessary to adopt another model approach and describe such problems.

Scheidegger (1998) defines porous media as any solid body that contains empty spaces called pores inside it. As, however, there is immense heterogeneity; the characterization of parameters of these bodies is based on averages and representative data of the whole body. The Darcy equation can describe the simplest cases of flows through porous media.

2.2 Darcy’s Law for Monophasic Fluid Flow

Darcy's law or Darcy’s equation describes the fluid flow through a porous medium. The law was formulated by Henry Darcy based on his laboratory experiments on water flow through layers of sand. Darcy's law (Eq 2.2.1) at constant elevation is a simple proportional relationship between the rate of instantaneous discharge through a porous medium, the viscosity of the fluid, and the pressure drop over a given distance (Atangan, 2018).

$$\frac{q}{A} = -\frac{k}{\mu}(\nabla p - g\rho\nabla z) \qquad \text{(Eq 2.2.1)}$$

Where q is the flow expressed in volume per time, A is the area, k is the intrinsic permeability of the medium, p is pressure, g is gravity, z is the coordinate relative to the adopted reference, μ is the dynamic viscosity of the fluid, ρ is the density of the fluid, and v is the average velocity of the section.

Depending on the mathematical definition, the measurement units used, and the parameter application, the definition ranges for the flow regime may change. In his experiments in tubes, Reynolds first was able to transform the flow into three different regimes: the first is characterized as a laminar flow regime, that is, Reynolds Number (Re) lower than 2100. A second transition regime characterized by Re between 2100 and 4000, where there is a region of uncertainty, the transition from the laminar regime to the turbulent flow regime. The last and last phase can be distinguished as turbulent flow regime by numbers above Re>4000 (Pereira et al, 2008). The Reynolds Number can be obtained as:

$$Re = \frac{\rho V L}{\mu} \qquad \text{(Eq 2.2.2)}$$

Where ρ is the density of the given fluid, v is the velocity of the fluid, L is a linear dimension, usually the length of the tube, and μ is the dynamic viscosity.

For flow in porous media, Dvbbs and Edwards (1984) observed, from experiments, that factors such as pore geometry and grain organization are determinants for the flow regime, especially when Re<1. In their experiments in porous media, the beginning of the transition was observed from Re=150 and chaotic turbulence for values above 300. In any case, there is a vast literature, and several models already proposed that allow investigating the flow regime in the porous medium. For this study, the Reynolds number's definition and flow regimes' design are sufficient.

2.3 Biphasic Systems

For two-phase systems, when directly applying Darcy's law, it is assumed that there are no interfacial tensions between the fluids and between the solid surface, considering that only the gravitational and pressure gradients are responsible for dictating the flow regime. Several factors such as capillary pressure, wettability, interfacial forces, and relative saturation of fluids directly influence the two-phase flow (Li et al, 2005), so an analytical solution to the problem is difficult to achieve. For issues of steady-state conditions and laminar flows, through mathematical development, it is possible to demonstrate the validity of Darcy's law for each phase:

$$v_i = -\frac{kk_{r,i}}{\mu}(\nabla p - \rho g) \qquad \text{(Eq. 2.3.1)}$$

Where i indicates the phase, k is the absolute permeability and k_r is the relative permeability that will be explained section 2.7. In any case, Li et al (2005) demonstrated a series of other numerical and analytical models capable of well describing the flow in two-phase systems for specific situations.

2.4 Multiphasic Systems

For multiphase systems having three or more phases, the simplifications adopted previously often compromise the resolution of the problem so that the equations developed do not provide results compatible with reality. To better understand these problems, it is necessary to adopt partial differential equations that do not have a general analytical solution so far.

Such equations are the so-called Navier-Stokes equations, which start from Newton's principle of conservation of motion, applying it to infinitesimal elements of fluids. For Newtonian fluids under isothermal flows and where compressibility effects can be neglected, these equations can be represented, in cartesian coordinates, as follows:

$$\frac{\partial}{\partial x}\left(\rho\frac{k_x}{\mu}\frac{\partial p}{\partial x}\right)+\frac{\partial}{\partial y}\left(\rho\frac{k_y}{\mu}\frac{\partial p}{\partial y}\right)+\frac{\partial}{\partial z}\left(\rho\frac{k_z}{\mu}\frac{\partial p}{\partial z}\right)=\phi c_t\rho\frac{dp}{dt}, \qquad \text{(Eq 2.4.1)}$$

Where x, y and z are the directions in a cartesian system, ϕ is the porosity, and c_t is the total compressibility.

The Navier-Stokes equations seek to relate the variations in particle velocities in time and space, plots to the left of the equality, with the forces acting on the flow, plots to the right of the equality (Lofrano, 2018). However, even though it has been known for over 200 years, there is still no general analytical solution for such an equation and even though it is the mathematical description for a problem of nature, there is no demonstration, so far, that such solutions exist. The Navier-Stokes equation is one of the problems that most intrigues mathematicians, and there is a prize of US$1,000,000.00 offered by the Clay Institute to whoever can solve it.

Anyway, for this work, by adopting some boundary conditions and discretizing the problem on a defined scale, it is possible to find approximate numerical solutions considering:

- Mass conservation;
- Conservation of momentum (Newton's Second Law);
- Conservation of energy (First Law of Thermodynamics).

Through mathematical manipulations of these three principles, it is possible to arrive at the hydraulic diffusivity equation:

$$\nabla \mathrm{p}^2=\frac{\phi c_t \mu \partial p}{k \partial t} \qquad \text{(Eq 2.4.2)}$$

In petroleum engineering applications, it is common to adopt cylindrical coordinates since the well geometry is used as a reference. In cylindrical coordinates a, the same equation can be expressed as follows:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial p}{\partial r}\right)+\frac{1}{r^2}\frac{\partial^2 p}{\partial \theta^2}+\frac{\partial^2 p}{\partial z^2}=\frac{\phi c_t \mu \partial p}{k \partial t} \qquad \text{(Eq 2.4.3)}$$

There are numerous solutions already developed for different situations that will not be addressed here. Still, for this study, it is important to emphasize that permeability plays a fundamental role in the flow in porous media.

2.5 Saturation

The reservoir is composed of the rock matrix and the pore space filled with different fluids. Saturation is defined as the relative concentration of the fluid phases, normally expressed in percentage terms. The sum of the saturations of the different phases is equal to 1. Thus, for hydrocarbon reservoir systems, it is convenient to define saturation for the oil, water and gas phases.

$$S_w + S_o + S_g = 1 \qquad \text{(Eq 2.11.1)}$$

Where S_w is the saturation of water, S_o is the saturation of oil and S_g is the gas saturation.

During the lifetime of a field and even during laboratory measurements, it is noted that once the rock is saturated with two or more fluids, it is not possible to fully remove any of the saturation fluids. During the inhibition and drainage operations, it is noted that the saturation of the displaced fluid tends to decrease until a value above 0, at which point this phase becomes immobile and it is no longer possible to displace this fluid with a pressure gradient. Valentine, Valentine and Koederitz (2002) define irreducible water (S_{wi}) saturation as considered the lowest water saturation measured from a core sample using a centrifuge or core-flood techniques and can be assumed that is the lowest water saturation naturally possible for that system. The same concept can be applied to the oil phase to define the residual oil saturation and to the gas phase to define the critical gas saturation.

2.6 Absolute Permeability

When there is only one fluid saturating the porous medium, we can experimentally measure the ability of this medium to transmit this fluid given a pressure gradient. This property is called absolute permeability (k_{abs}) and it is expressed in Darcies (corresponding to 10^{-12} m^2 in the SI), or more commonly, milli Darcies.

2.7 Effective Permeability

Satter and Iqbal (2016) define the effective permeability of rock to a fluid phase (oil, gas, or water) in a porous medium as the ability of this phase to flow in the presence of one or more other fluid phases. Therefore, effective oil permeability is a measure of its ability to flow in the presence of water and, in some cases, water and gas phases. This measure is obtained from laboratory studies, where through a forced flow and one of the phases over the medium saturated with another immiscible fluid, the effective permeability for the individual phases (k_{eff}) is determined and expressed in darcies or militaries. It is important to emphasize that the fluid saturation in the porous medium directly influences its permeability, with saturation values where there is no mobility for certain phases.

2.8 Relative Permeability

Satter and Iqbal (2016) define the relative permeability of rock to a determined fluid as the ratio of the effective permeability of the respective fluid phase to the absolute permeability of the rock. In this way, the relative permeability is expressed as a dimensionless property relative to oil, water, or a particular gas.

$$k_{ro} = \frac{k_o}{k} \qquad \text{(Eq 2.7.1)}$$

Where $k_{ro}$is the relative permeability of the oil phase, k_o is the effective permeability of oil and k is the absolute permeability.

It is important to note that permeability values are usually direction-dependent, so the permeability is not a scalar value but determined by a tensor. If the medium presents the same permeability values for different directions in the adopted reference system, it is called isotropic; if not, we call it anisotropic.

2.9 Hysteresis

Several properties of nature present a historical dependence. Some systems tend to preserve the properties even in the absence of the factors that generate this particular property. This phenomenon is called hysteresis and can be seen in magnetism, piezoelectric properties, ceramics, and even in social factors such as unemployment. For this study, we call hysteresis the difference in permeability when changing the saturation history so that permeability takes on different values during drainage and imbibition processes (Ahmed, 2019), as evidenced by Figure 2.1.

In Fig. 2.1 the red curves show the experiment starting with the highest possible oil saturation, around 0.9. As oil saturation decreases, the relative permeability of the oil decreases (solid line) while the relative permeability of the gas increases (dotted line). The curves in blue represent the same experiment starting from the highest possible gas saturation, increasing the saturation of the oil phase. The difference in the path taken by the two curves is called hysteresis.

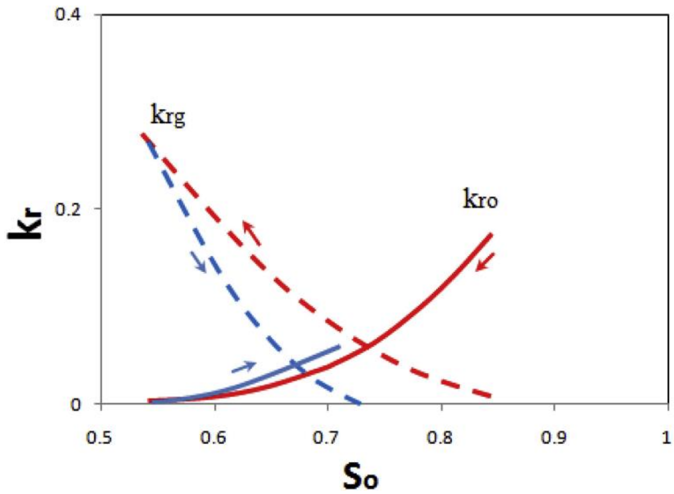

Figure 2.1 - Gas/Oil relative permeabilities hysteresis. Source: Osoba et al apud Fatemi and Sohrabi (2018)

2.10 Wettability

Agbalaka et al (2008) define wettability as the tendency of a reservoir rock to maintain a given fluid in a multi or two-phase system in contact with its surface. In this way, an oil-wetted rock will tend to have adsorbed oil on its surface. Thus, when we think about the flow in porous media, wettability will be decisive in the dynamics of fluids during production since a water-wet rock will tend to retain water in its porous wall, while hydrocarbons (gas and oil) will be more mobile and tend to flow through the pores. Thus, formations with favorable oil wettability tend to have even lower recovery factors.

The tendency of a liquid to spread over the surface of a solid indicates the wettability characteristics of the interaction between the solid, the dispersion medium, and liquid in contact with the solid, so the balance of interfacial forces determines the shape of the drop. It is convenient to express wettability by measuring the contact angle at the liquid-solid surface, so this is a direct measure for characterizing the wettability of a solid to that system.

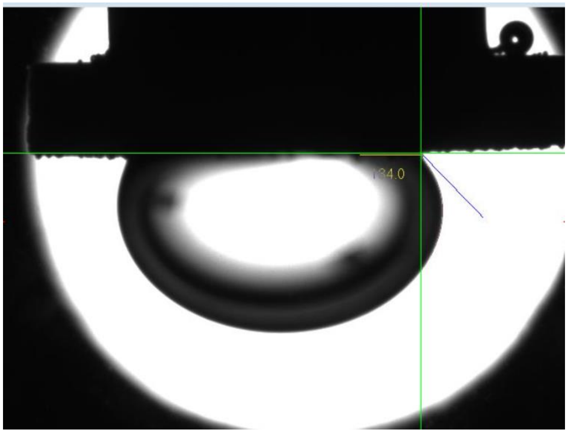

Figure 2.2 - Example of contact angle measurement in a rock sample with a drop of oil in a brine dispersion system. Source: Author.

Depending on how the experiment is carried out, changing the dispersion medium and the droplet phase between water, brine, and even air, we can have different interpretations for the measurement of the contact angle. To parameterize the analysis, some authors define that such a measurement should always be performed with the densest phase (Dimri et al, 2012). Still, there is no unanimity in the literature. Therefore, it is always recommended to describe the measurements concerning the experiment performed.

Recent research also evaluates that the saturation history of the sample also directly influences the wettability characteristics of the solid not only over geologic time but also within drilling and production time scales. Drilling fluids, particularly oil-based muds, contain surfactants that can invade pore spaces. This invading fluid can alter wettability in the near-well region, affecting flow when the well is put into production. (Abdallah et al., 2007). Silveira et al (2022) also demonstrated that the sample cleaning process normally used ends up altering the petrophysical properties of the rocks and leading to mischaracterization. Therefore, it is important to take these types of uncertainties into account.

2.11 Capillary pressure

When there is more than one fluid saturating a medium, the balance of interfacial forces leads to a surface tension between the two fluids. The difference between the pressure in the non-wetting phase and in the wetting phase is called capillary pressure.

Franchi (2002) defines capillary pressure as the pressure difference across the curved interface between two immiscible fluids in contact in a small capillary tube. Capillary pressure can be defined mathematically as:

$$p_c = \frac{2\sigma cos\theta}{r} \qquad \text{(Eq 2.9.1)}$$

Where p_c is the calculated capillarity pressure, σ is the interfacial tension between the phases, r is the radius of curvature of the interface, θ is the wetting angle that can be experimentally obtained.

This pressure causes a kind of suction, leading to a phenomenon in which liquid spontaneously rises or falls in a narrow space such as a thin tube or the voids of a porous material called capillary rise (Kaliakin, 2019).

2.12 Interfacial Tension

A tension always exists at the interface of fluid phases due to unbalanced molecular constitutional forces. These tensions that arise between fluids in a multiphase system are called interfacial tensions.

The evaluation of gas-liquid interfacial tension is one of major interest in gas injection processes where the relative magnitudes of surface, gravitational and viscous forces affect the recovery. For this study is sufficient to address that the capillary pressure is the concept which is often used in reservoir studies to consider the effect of surface forces on the fluid distribution within a reservoir and is related to the interfacial tension and the pore characteristics, and it has been established also that the relative permeability, which describes the multiphase flow behavior on the reservoir, may strongly depend on the interfacial tension (Danesh, 1988).

However recent studies published by Benson et al (2015) concluded that for CO_2 - Brine and N_2 – Brine systems two experiment sets suggested that changing the interfacial tension from 35 to 65 mN/m did not have a significant effect on the measured relative permeability curves. The authors concluded that interfacial tension variations are not likely to have a significant impact on relative permeability curves for conditions representative of typical geological storage reservoirs.

3 PERMEABILITY CURVES

In multiphase flow in porous media, each phase presents a distinct behavior according to its physical-chemical interactions with the rock and with the other fluids present in the system. Thus, according to Fanch (2018) reservoirs can be classified into:

- Reservoirs slightly water-wet;
- Reservoirs slightly oil-wet;
- Reservoirs that are highly water-wet;
- Reservoirs heavily oil-wet
- Neutral reservoirs in terms of wettability;

The distribution of the phases present in the flow will vary according to the wettability characteristics, resulting in distinct relative permeabilities. In practical terms, in water-wet systems, capillary forces tend to hold the water phase into the pores, whereas in the case of wet oil system, the oil phase tends to be adsorbed in the pores while the water phase tends to flow. Kantzas et al (2016) describes that, because of capillary forces, the wetting phase occupies the smaller pore openings at small saturations, and these pore openings do not materially contribute to the flow, it follows that the presence of a small saturation of the wetting phase will only affect the permeability of the wetting phase. On the other hand, since the non-wetting phase occupies the central or larger pore openings that materially contribute to the fluid flow through the reservoir, the relative permeability to the wetting phase is characterized by a quick decline its magnitude for small decreases in the wetting phase.

When the lowest possible saturation of water present (irreducible water saturation) is reached the water permeability tends to zero. One explanation for this is that the capillary forces in the small pores prevent the flow of this phase. Another important phenomenon associated with the flow of fluid through porous media is the concept of residual saturations already mentioned in the introduction to this work. When one immiscible fluid is displacing another, it is impossible to reduce the saturation of the displaced fluid to zero due to physicochemical interactions. At a small saturation, which is assumed to be the saturation in which the shifted phase ceases to be continuous, the flow of this specific phase ceases and this saturation is characterize as the residual saturation. It is also important to point out that it is necessary to reach this minimum saturation, a fluid must develop a certain minimum saturation before the phase begins to flow. The saturation at which a fluid will begin to flow is called critical saturation.

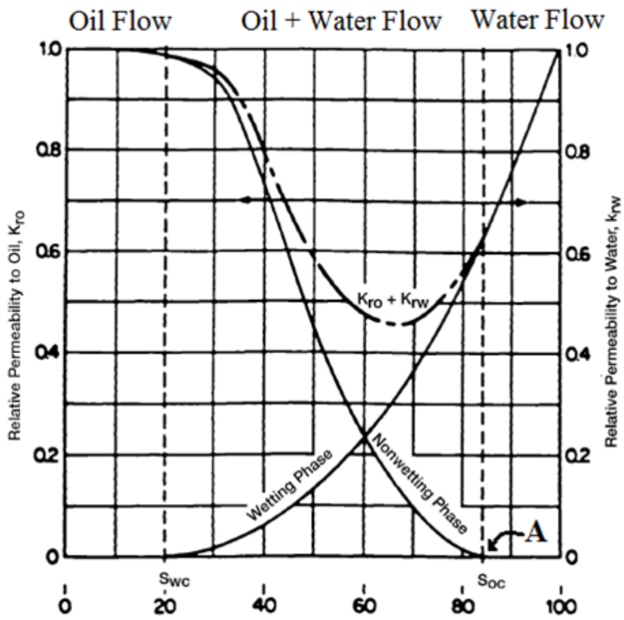

Figure 3.1- Example of Permeability Curve Measurement. Source: Kantzas et al (2016).

To illustrate what happens physically, for two-phase systems with water saturations below the S_{wi} (approximately 20% for the graph above) there will only be oil flow. Analogously, the oil phase is not mobile at saturations below critical saturation (approximately 18% in the example above). For any intermediate saturations there will be a two-phase flow, characterizing the relative permeability curves.

In the physical sense of the construction of permeability curves, there are two experimental possibilities for their realization: either increasing or decreasing gradually the water saturation in the system. Kantzas et al (2016) define that drainage relative permeability refers to a saturation change where the wetting phase is decreasing, while imbibition refers to the curve which the wetting phase saturation is increasing. The figure below illustrates the different directions of carrying out the experiments. Ideally, the values found by the two experiments would be the same, however, the permeability curves are strongly influenced by the saturation history so that there is the presence of hysteresis.

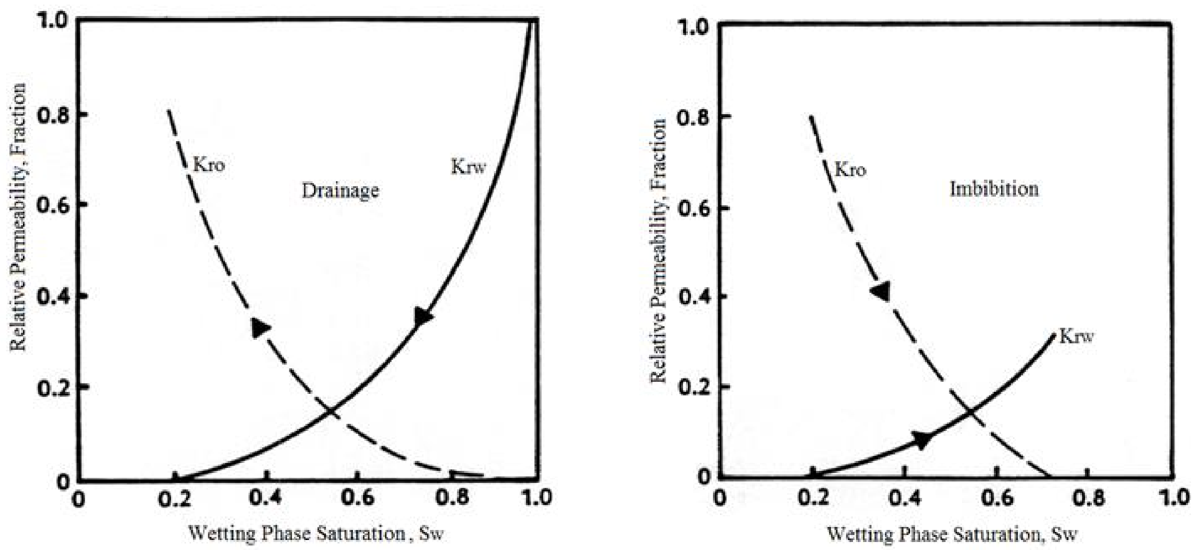

Figure 3.2- Example of Drainage and Imbibition Curves. Adapted from Kantzas (2016).

Several authors have dedicated themselves to investigating different methods and techniques for measurements under different conditions for the construction of permeability curves. Several works can be found with specific details on such measurement and prediction methods. For the purposes of this work, the main methods found in the literature will be listed. Those methods were developed during the last century, however most modern authors use adaptations of these methods.

According to Kantzas et al (2016), the effect of many parameters on relative permeability and/or effective permeability characteristics was object of different studies, and the main parameters influencing the permeability curves are:

- Wettability;
- Pore geometry;
- Heterogeneity of the system;
- Anisotropy of the system;

- Fluid viscosity;
- Interfacial tension (IFT);
- Temperature;

Each of these parameters has been the subject of evaluations by different authors under different conditions, but the permeability curves are more sensitive to changes in wettability (Anderson, 1987). Owens and Archer (1971) experimentally showed this strong dependence and Anderson (1987) states that wettability affects relative permeability because it is a major factor in the control of the location, flow, and distribution of fluids in a porous medium, so that in uniformly wetted porous media, the water relative permeability increases and the oil relative permeability decreases as the system becomes more oil-wet .In a mixed-wettability system, the continuous oil-wet paths in the larger pores alter the relative permeability curves and allow the system to be waterflooded to a very low residual oil saturation.

Chapter 3 is dedicated to evaluating the effects of the major components in affecting the permeability of the formations and to provide a theory background revision usually assumed in the experiments and models of permeability curves.

3.1 Single phase or absolute permeability

Permeability can be defined as the ability of a medium to allow the flow of a given fluid. In the definition presented by Darcy we see the permeability defined for a single flow direction, however in complex systems in which it is necessary to analyze problems in 3 dimensions, the permeability becomes a tensor.

According to McPhee et all (2015-A), absolute permeability is usually determined by routine (or basic or conventional) core analysis involving fluid saturation measurements and petrophysical measurements on dry plugs and samples at ambient or laboratory conditions. The experiments basically consist of creating the flow of a fluid through a pressure difference in a rock sample and, using Darcy's formula, the representative value for the absolute permeability is calculated.

In case of need for a more detailed approach Holden and Lia (1991) developed an algorithm capable of estimating the effective permeability tensor based on one-phase incompressible flow for heterogeneous reservoirs.

3.1.1 Effects of Rock Heterogeneities

Due to the sedimentary nature of the hydrocarbon reservoirs, the reservoir usually presets layered bedding planes. Considering a probability distribution for the heterogeneities makes the analysis extremely complex. Nonetheless, it is possible to provide an analytic solution for simple systems of different permeabilities that occur within core analysis and reservoir systems organized as:

- Linear beds in parallel as in Fig 3.3, or;
- Linear beds in series as in Fig 4.4.

3.1.1.1 Linear Beds in Parallel

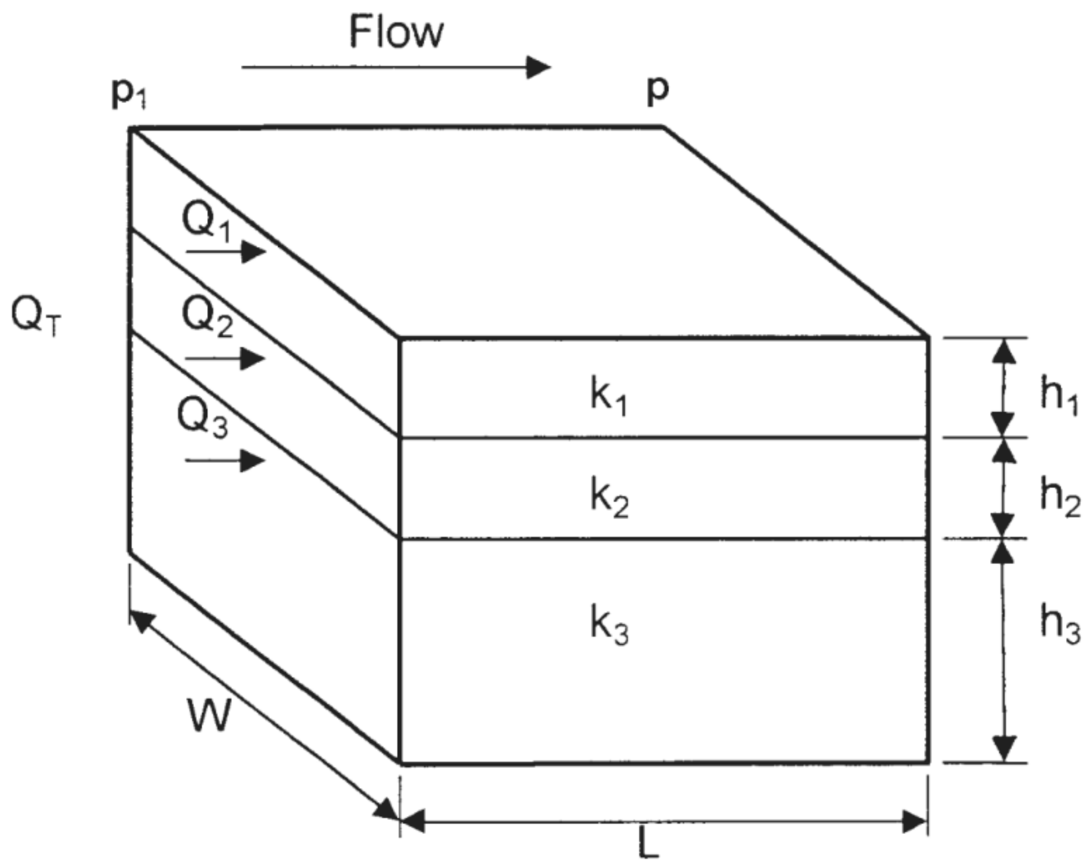

Figure 3.3 - Fluid Flow in Linear Beds in Parallel. Adapted from Ahmed (2010).

For this case, we can consider that the difference between the inlet and outlet pressures of each layer will be equal. Thus, it is sufficient to isolate the pressure difference in the Darcy equation for each layer to obtain the partial flow.

The total flow can be defined as the sum of the partial flows, so we can obtain:

$$q_t = \frac{k_{avg} w h_t \Delta p}{\mu L} \quad \text{(Eq 3.1.1.1.1)}$$

Where q_t is the total flow, k_{avg} is the average permeability, p is the pressure and h, L and w are the dimensions presented in the figure 3.3.

And also, as the sum of the partial flows:

$$q_t = q_1 + q_2 + q_3 \quad \text{(Eq 3.1.1.1.2)}$$

Where q_n is the partial flow of the layer n.

Substituting the mathematical definition of the flows given by Darcy's equations we will have:

$$\frac{k_{avg} w h_t \Delta p}{\mu L} = \frac{k_1 w h_1 \Delta p}{\mu L} + \frac{k_2 w h_2 \Delta p}{\mu L} + \frac{k_3 w h_3 \Delta p}{\mu L} \quad \text{(Eq 3.1.1.1.3)}$$

Where k_n is the permeability of the layer n.

Simplifying the difference of pressures and rearranging the formula we will have:

$$k_{avg} = \frac{\sum k_i h_i}{\sum k_i} \quad \text{(Eq 3.1.1.1.3)}$$

Thus, for this case it is possible to calculate the permeability of the system as a weighted average of the permeabilities of the sections.

3.1.1.2 Linear Beds in Series

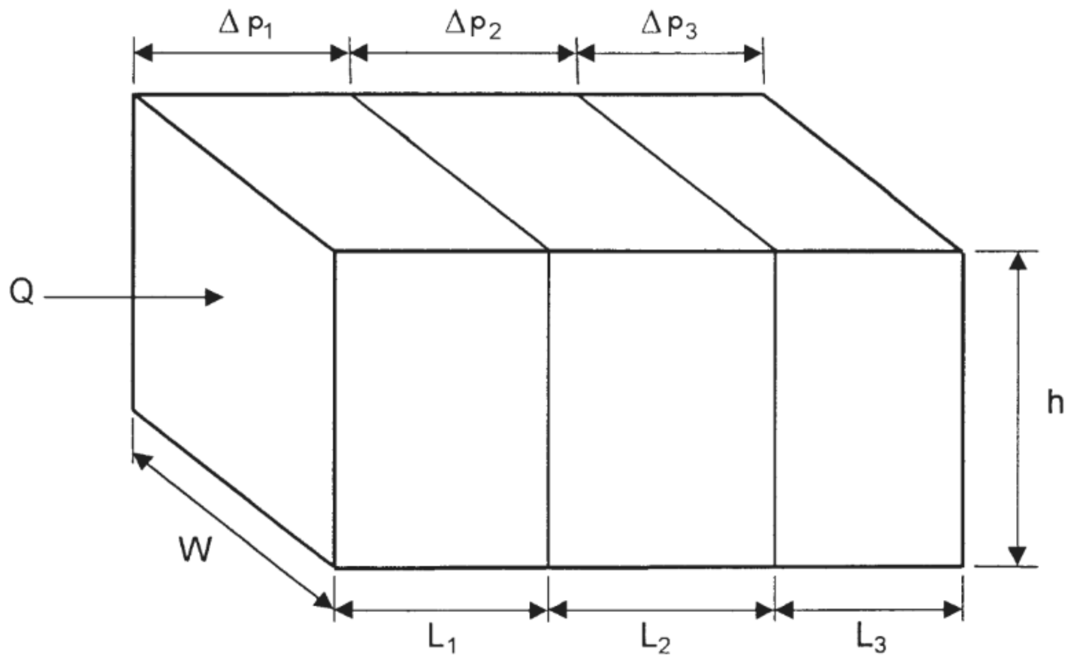

Figure 3.4- Fluid Flow in Linear Beds in Series. Adapted from Ahmed (2010).

For this system, each layer has a different pressure, however it is reasonable to assume that there is no accumulation of material and that, under these conditions, the flow is incompressible. Thus, the inflow is numerically equal to the outflow for each layer, as well as for the system. So:

$$\Delta p = \Delta p_1 + \Delta p_2 + \Delta p_3 \qquad \text{(Eq 3.1.1.2.1)}$$

Where Δp_n is the differential pressure of layer n.

Substituting the definitions of pressure differences given by Darcy, we get:

$$\frac{q\mu L}{k_{avg} wh} = \frac{q\mu L_1}{k_1 wh} + \frac{q\mu L_2}{k_2 wh} + \frac{q\mu L_3}{k_3 wh} \qquad \text{(Eq 3.1.1.2.2)}$$

Where w, h and L_n are the dimensions presented in Figure 3.4.

Algebraically manipulating the formula, we get:

$$k_{avg} = \frac{\sum L_i}{\sum\left(\frac{L}{k}\right)_i} \qquad \text{(Eq 3.1.1.2.3)}$$

Thus, for this case, the permeability can be obtained by the harmonic average of the permeabilities of the different layers.

Several authors have also proposed other types of relationships to obtain a representative permeability value, but the two cases analytically demonstrated above are well accepted and adopted to solve some simpler problems and can be used.

3.2 Permeability Curves

The permeability curves measurements are organized differently according to the number of phases present in the experiments. When only two phases are present, as in the case of CO_2 injection into aquifers or in the production of gas reservoirs, the system becomes simpler, and it is necessary to analyze the envelope of two phases.

Three-phase flow situations occur when gas is injected into an oil reservoir or when an oil reservoir is produced at a pressure below its bubble point, that is, for unsaturated reservoirs, so the pressure difference given by the well opening will eventually lead to a fluid flow that, depending on the relative saturations, can be multiphase, so that the flow will be guided by the permeability curves.

The Two-phase envelope was already described in Figure 3.1. For three-phase systems, usually, the data can be organized in a triangular chart. Ahmed (2010) states that in a three-phase system, the relative permeability of the water phase depends only upon its phase saturation for each system. However, the fluid distribution varies with the wettability of the systems.

In the case of the study of three-phase flow, as the saturations are defined by three values, it is usually necessary to use a triangular diagram, where each vertex represents a point whose saturation of the corresponding fluid is 100%. In this type of graph, the isoperm is defined as the constant relative permeability curve for one of the phases and then the data is plotted against the evolution of the saturations.

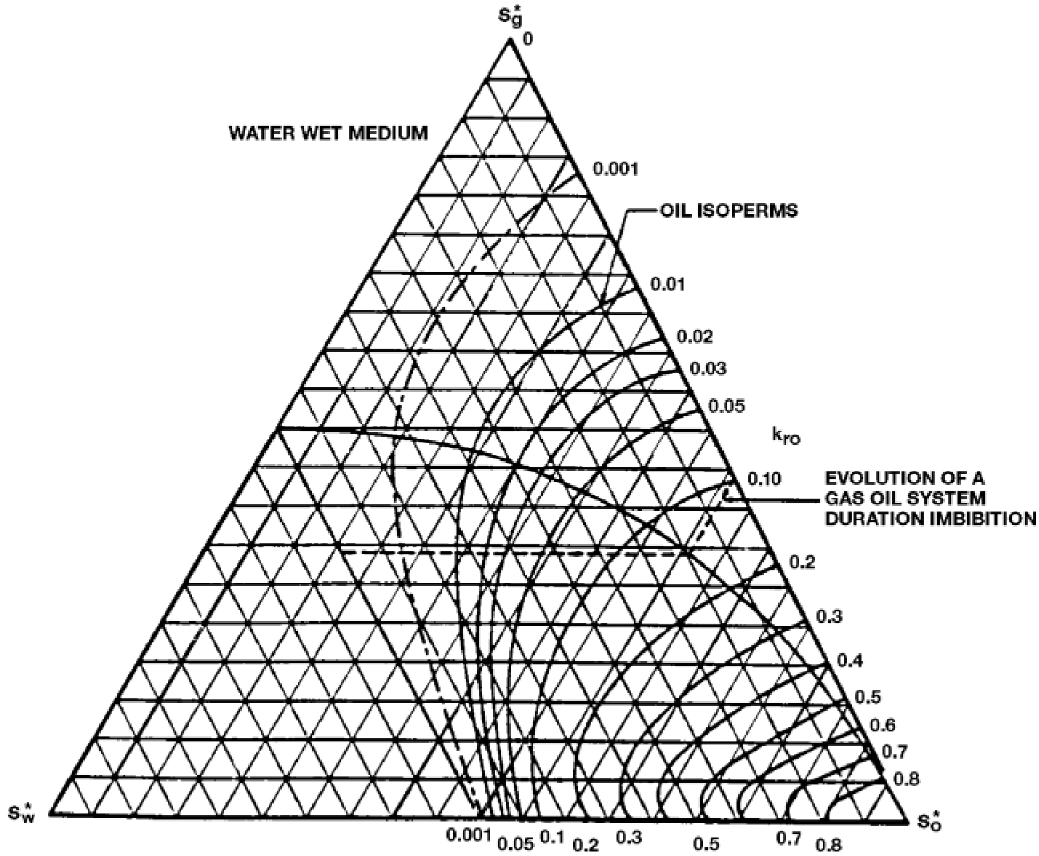

Figure 3.5- Example of Three Phase Saturation Diagram. Adapted from Ahmed (2010).

Kantzas et al (2016) state that due to the complex nature of three-phase relative permeability experiments and the lack of agreement between the limited data, many models were developed to generate three-phase relative permeability values.

Once stated the general points of the permeability curves are, is necessary to discuss some concepts before introducing the measurement methods.

3.2.1 Buckley-Leverett Theory of Displacement of Non-miscible Fluids

The Buckley–Leverett equation introduced by Buckley and Leverett (1942) or the frontal-advance equation, is the simplest equation used to describe immiscible displacement in a linear reservoir. The equation is based on the following considerations: the flow takes place in a two-phase system, in a linear, homogeneous, and isotropic porous medium, the fluids are considered incompressible, and that there is no change of phases, in the general case, the effect of capillary pressure is also neglected.

To understand the theory is necessary to introduce the concept of fractional flow. The fractional flow of a fluid is defined as the quotient of the flow rate of that fluid and the total flow rate. The fractional flow of water, represented by the symbol $f_{w,}$ is the relationship between the flow rate of water, q_w, and the total flow rate, q_t. As such the fractional oil flow (f_o) is the ratio of the oil flow rate to the total rate. A generic formula for the fractional flow can be defined as:

$$f_x = \frac{q_x}{q_t} \qquad \text{(Eq 3.2.1.1)}$$

The step-by-step demonstration of the equation is not complex, but long and there is no need to demonstrate it again. The demonstration can be found in the cited work or in Ahmed (2010) and Dake (1978). To the purpose of this work, the fractional flow of water can be calculate by the following equation.

$$f_w = \frac{1}{1+\frac{k_o \mu_w}{\mu_o k_w}} \qquad \text{(Eq 3.2.1.2)}$$

Where μ_n is the dynamic viscosity of phase n and k_n is the effective permeability of phase n.

The relative permeability can be back calculated by fitting the flow rate data, so that it is a function only of the fluid viscosities and the effective or relative permeabilities. Not coincidentally, the results obtained with this equation are similar to the results obtained experimentally for the permeability curves, showing that the model developed is consistent. Buckley-Leverett Theory is the basis of the most mathematical models for permeability curves.

3.3 Klinkenberg Effect

Klinkenberg (1941) reported the variation in permeability test results with pressure when gas was used as the fluid to perform the test. The permeability measurements performed in the laboratory using a gas resulted in values higher than the real ones due to the sliding of the gas on the walls of the porous medium, which didn't occur with liquids. Klinkenberg found that for a given porous medium, as the average pressure increased, the calculated permeability decreased.

Rosa et al (2006) state that as the average pressure of the gas increases, it tends to behave similarly to a liquid and the calculated permeability decreases, up to a limit where, for a hypothetically infinite average pressure, the gas would transform into liquid and the permeability thus measured would be equal to the absolute permeability. To correct this effect, Klinkenberg (1941) proposed the relationship:

$$k = k_{\infty}(1 + \frac{b}{p_{avg}}) \qquad \text{(Eq 3.3.1)}$$

Where k is the permeability value measured in the experiment, b is a constant, p_{avg} is the average pressure of the experiment and k_{∞} is the absolute permeability. The parameter b, called the Klinkenberg factor, is a function of the type of gas used and the permeability of the porous medium.

3.4 Forchheimer Effect

For high flow rates of gases in porous media, the flow becomes turbulent as the velocity of the gas flows through the pores is very high. As Darcy's law can be interpreted as a laminar flow solution of the Navier-Stokes equation, the solutions need to be adapted to match reality. In these circumstances, the appropriate flow equation is the Forchheimer equation. In the Equation 3.4.1 the first term is the Darcy or viscous component, while the second is normally referred as the non-Darcy component where β is the coefficient of inertial strength.

$$\frac{dp}{dr} = \frac{\mu}{k} v + \beta \rho v^2 \qquad \text{(Eq 3.4.1)}$$

Basilio and Navarro (2016) defines the Forchheimer effect, also known as non-Darcy effect or inertial effect, as the phenomenon of extreme conditions of velocity which are determined by inertial forces resulting from the convective acceleration of fluid particles in the medium around the borehole, in addition to viscous forces and resulting in a decrease in the relative permeability. The importance of highlighting this effect here is that, in the case that the inertial effect cannot be neglected, usually in gas wells, the permeabilities cannot be calculated using Darcy’s equation. In this case, another approach is necessary to grant an accurate and representative value for the permeability.

4 THE PERMEABILITY CURVES MEASUREMENTS

There are several methods and literary descriptions for performing relative permeability measurements. Section 4 will be dedicated to discussing different methods and comparing them. Experiments usually begin with the sample cleaned, either in its natural state or aged in a medium of the author's choice. Initially, the sample is saturated with the fluid of interest, most commonly with a synthetic brine based on field data or even low salinity water for specific cases. Once the sample is saturated, an immiscible fluid, usually a synthetic oil or dead oil obtained from a field, is forced to flow, simulating the migration process until a point is reached where the flow of the sample is only of oil. Evaluating the inlet and outlet flows with a simple material balance it is possible to obtain the relative permeability curves as well as the irreducible water saturation and the critical oil saturation.

4.1 Sample Cleaning

Relative permeability measurements usually start with samples that have been previously cleaned. It is important to note that cleaning the samples can result in a significant change in the wettability of the sample as it will be highlighted in this session, so it is important to consider the cleaning method used.

API RP40 (1988) lists the 5 main methods for cleaning core samples:

- Flushing by centrifuge;
- Liquefied gas extraction;
- Distilation-extraction;
- Gas-driven solvent extraction;
- Gas-driven extraction;
- Solvent flush cleaning by direct pressure.

Best practices for Special Core Analysis (SCAL) were described by McPhee et al (2015-B), and it was established that the selection of the most appropriate method will depend on the purpose of the study, the rock lithology, and the potential contamination of the core wettability. McPhee et al (2015-B) also listed as main advantages and disadvantages of the 3 most used cleaning methods that we can highlight:

4.1.1 Standard Soxhlet Extraction

Cheaper and faster method and applicable to the vast majority of samples so that several samples can be cleaned simultaneously, however it is performed at high temperatures which can lead to a change in unstable crystals in the rocky pores (McPhee et al ,2015-B).

4.1.2 Submerged Cleaning Soxhley

Another simple and considered a low-cost method in which, because the sample is immersed in solvent, there are no evaporation cycles and is a method designed to prevent core damage. However, it is a method that proves to be inefficient when the sample is contaminated with some types of mud and oils (McPhee et al ,2015-B).

4.1.3 Flush Cleaning

High reliability test normally used in specialized laboratories with more developed and specific equipment. It is a quick and efficient test that can be performed at low temperatures, preserving thermal damage to samples, especially clays, and being ideal for poorly consolidated samples, since it is possible to keep them under confinement. However, given the flow condition, it is possible to observe the migration of fines and it is an expensive test to apply at the commercial level (McPhee et al ,2015-B). It is not a recommended test for low permeability samples for obvious reasons.

Anderson (1987) published a series of studies a series of literature surveys covering the effects of wettability on core analysis analyzing various effects that have been shown to affect waterflood behavior, relative permeability, capillary pressure, irreducible water saturation (IWS), ROS, dispersion, simulated tertiary recovery, and electrical properties and stated that the most accurate relative permeability measurements are made on native-state core, where the reservoir wettability is preserved. Serious errors can result when measurements are made on cores with altered wettability, such as a core contaminated with drilling-mud surfactants.

Jennings (1957), however, performed several measurements in water-oil systems using the “Penn State” method, which will be better described below, on rock samples before and after cleaning with Toluene. A comparison of curves obtained before and after cleaning showed small variations in measurements that can be explained by experimental deviations. Jennings (1957) concluded that the laboratory procedure of core cleaning with toluene extraction and subsequent handling during core analysis does not significantly change the relative permeability characteristics from those of the core material at the start of the core analysis operation. This conclusion is based on data from cores that were preferentially water-wet, cores that were preferentially oil-wet, and cores that were of intermediate wettability.

This divergence between different authors is found in several other studies and it was highlighted here to show that this issue is not pacified in the literature.

4.2 Steady State Methods

The steady state method consists in promoting the flow rate of each phase at the core output changes as the saturation inside the core plug changes. Eventually, saturation reaches a steady state and each phase enters and leaves the core at a constant flow rate. The pressure drop across the core plug is assumed to be the same for both fluids. In this case, the relative permeability is determined from Darcy's law for linear flow.

Kantzas (2016) states that the Steady-State methods of relative permeability measurements are the most reliable source of relative permeability data since it is possible to use Darcy's law to determine the effective permeability for each phase at a determined saturation. To perform the experiment the two immiscible phases are injected simultaneously into the sample at constant rates or pressures. The steady state is considered when the measured pressure drop remains stable.

Baker et al (2015) provide a very detailed explanation of how to obtain drainage and imbibition curves. In the work, the experimental procedure was described in a water-oil relative permeability test and when the core was initially saturated with brine, the permeability at 100% water saturation was determined. This was done considering the absolute permeability as it was defined in the previous sections of this work. Thus, water was forced to flow through the core at a relatively high flow rate and oil was forced to flow at a relatively low flow rate. The oil flow was incrementally increased, while the water flow was incrementally decreased so measurements are obtained at successively lower steady-state water saturations. Eventually, only the oil flows through the core, and the relative permeability of the oil is measured at irreducible water saturation. The relative permeabilities at successively lower water saturations form the drainage curve. To obtain the imbibition curve, the process is reversed and the relative permeabilities are measured at successively higher water saturations. Eventually, the only water phase is flowing through the core plug, and relative water permeability at residual oil saturation is obtained.

Several authors claim that the advantage of the steady-state method is that the relative permeability calculation is fast, straightforward and requires few assumptions. The disadvantage is that it takes considerable time to reach steady state, so it is considered a time-consuming type of test, and cannot be applied when there is urgency for results. There are numerous steady-state methods available. Examples of these include the Penn State, modifications in the Penn-State method, and Hassler methods.

4.2.1 Hassler Method

Honarpour and Mahmood (1988) describe the Hassler technique as follows: porous plates are placed in contact with both ends. The wetting phase must pass through these fully saturated plates, while the non-wetting phase is introduced directly onto the face of the core. Pressures are kept below the threshold pressure so that the non-wetting phase does not enter the plates being capable of measuring the pressure of each phase separately, considering the pressure difference between immiscible phases.

Christiansen and Howarth (1995), refer to this method as the uniform capillary-pressure method stating that the capillary pressure between two flowing phases is kept uniform throughout a rock sample by keeping the pressure gradients equal in both phases. Because of the extraordinary challenges involved in implementing it, the method is sometimes avoided.

This method was the object of study by many authors during the last century and it was known for its complexity. Rose (1980) also tried to apply this method concluding that much more work in the experimental design of Hassler relative permeability systems apparently was required before an operational methodology will be achieved.

4.2.2 Penn State Method

Honarpour and Mahmood (1988) describe that the Penn State method, as a method that try to avoid the boundary effects by using a test core sample between two samples of similar porous material placed in contact with the inlet and outlet faces of the test core.

Osoba et al (1951) provides a detailed description for performing this method. Initially, the authors saturated the rock sample with oil, allowing oil to flow through the sample at a certain pressure difference. Concomitantly, a small flow of gas was allowed until equilibrium was reached, then the relative saturations were determined by weight. The cores were reassembled in the test apparatus and subjected again to the oil and gas flows. The authors noted a drop in oil flow that was offset by an increase in gas flow. Thus, whenever equilibrium was reached, the sample was weighed to determine the relative saturations, adopting this procedure repeatedly until the end of the permeability curve.

The authors also relate some difficulties in the realization of this experiment. Initially, they were filling the pores with gas pre-saturated kerosene. With saturated kerosene as the wetting phase, it was observed that the measured relative permeabilities to both oil and gas were erratic, however for the experiments conducted with kerosene from which most of the dissolved gases had been removed, the deviations were not found anymore.

Although this method was developed many years ago, it is still the most used experimental method as a basis for permeability measurements today. It’s common to find in the literature authors adopting some modification of the original method according to the apparatus available and the conditions of their systems. For this reason, this method was described in this work.

4.2.3 Braun and Blackwell Method

Braum and Blackwell (1981) developed a method capable of evaluating permeability curves under reservoir conditions. Using a normally enclosed oven that was kept at reservoir temperature. The entire system was also kept pressurized to simulate the conditions of the reservoir. The authors reported that the tests were successfully conducted at temperatures above 90 degrees Celsius and at pressures above 30 MPa (4350 psi).

The experimental apparatus can be schematically organized according to figure 4.1. The detailed description and technical specifications of the materials used can be found in the cited work. For the purposes of this work, it is sufficient to point out that the oil saturation was determined over time and over the length of the sample from electrical resistivity measurements. The relative permeabilities were measured using a modification of the Penn State method, and the shape of the stabilized zone and recovery at water breakthrough were calculated using both measured and computed relative permeability data and these agreed with the experimental, validating the model developed. The brine factional flow was determined by analyzing the saturation distribution data during the experiments using the continuity equation, assuming incompressible flow.

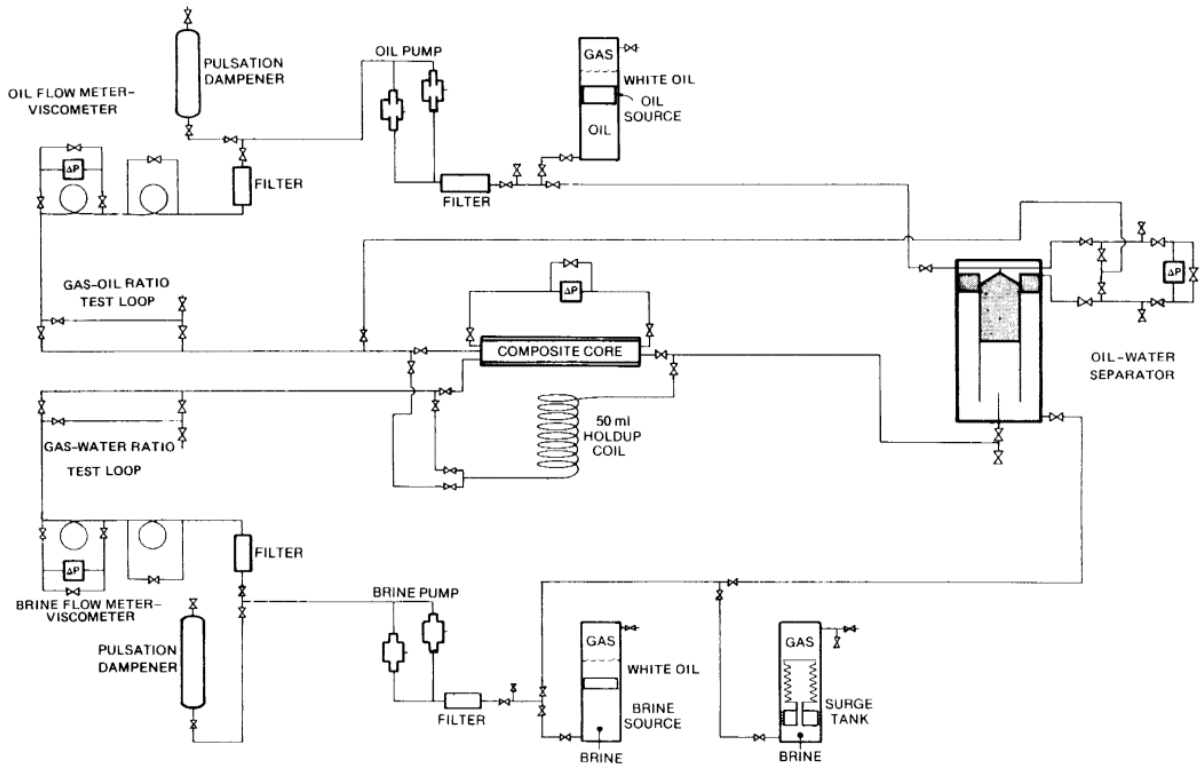

Figure 4.1- Braum and Backwell Method Apparatus. Adapted from Braum and Blackwell (1981).

The method is basically a variation of the Penn State method, but it was pointed here to highlight the possibility to simulate the reservoir conditions to carry out the experiments.

4.2.4 Imaging Techniques

Eleri et al (1995) developed a technique using images to evaluate permeability curves, using a modified medical CT scanner for use in hydrocarbon reservoir research. The scanner basically works with an X-ray source capable of building images of the interior of the cores to calculate the saturations and relative permeabilities.

The authors used a synthetic base brine containing a nuclear tracer with a sodium isotope, and a refined oil tagged with a radioactive isotope of iron to facilitate the visualization of the images. The steady state experiments were performed by increasing and then decreasing the brine saturation by the influx of oil and brine and the steady state was considered when there were no more significant changes in the CT images.

The results obtained showed great precision in the determination of the saturation of the phases along the sample in a relatively short time, being possible to characterize even points of apparent discontinuity in the evolution of the saturation along the samples, proving to be the only method capable of to provide such precision in detail. The need for this level of precision is debatable, not being necessary for most of the permeability studies involved. The study in question makes a comparison between different methods, showing that imaging methods are capable to provide detailed data making possible the comparison.

The authors observed the presence of reduced hysteresis during the performance of the experiment. An interesting observation evidenced by the authors was that the residual oil concentration reported in this test was abnormally low, being approximately 12%. The authors report that the test performance time may have caused a significant change in the wettability of the sample, being a factor to be considered for future works.

4.3 Unsteady State Methods

The Unsteady State Methods are based on the same principle of immiscible displacement. The difference between the two techniques is that saturation equilibrium is not reached during the unsteady state test. The test consists of confining a rock sample in a specific device, capable of controlling and/or measuring the inputs, outputs flows and differential pressure. In this case, fluids are not injected simultaneously into the core. Instead, the test involves the displacement of fluids with a constant rate or constant pressure driving fluid. The permeability curves are measured based on the output flow of both phases. A generic model of the apparatus can be found in Figure 4.2:

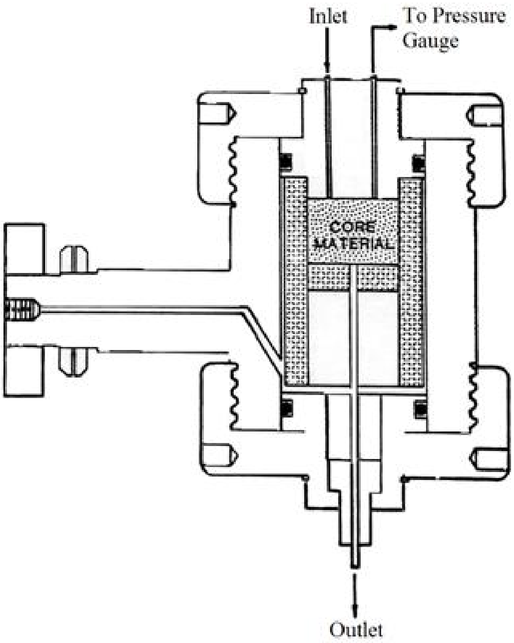

Figure 4.2- Unsteady State Basic Apparatus. Source: Kantzas et al (2016).

Since steady state is not reached, the problem cannot be solved using Darcy's Law. To address this problem usually the Buckley-Leverett for linear fluid displacement is used to develop the solutions. Some authors adapt the original solution to consider capillarity pressures. Kantzas et al (2016) points the Johnson-Bossler-Naumann (JBN) solution as the most used most for calculating relative permeabilities from unsteady-state displacement tests. This method will be further detailed in section 4.3.1 – JBN Method.

Kantzas et al (2016) also highlights that, for the unsteady state methods, the permeability curves are not a unique function of saturation, but are also dependent upon fluid distribution, in this way the final result will be influenced by the history of saturation and flow rates of the test and the sample. The authors state that the choice of test method should be made with due regard to reservoir saturation history, rock, and fluid properties. As already stated, the wetting characteristics will influence directly the final results, in this way test cores should either, be of similar wetting characteristics to the reservoir state, or their wetting characteristics should be considered to analyze the data.

4.3.1 JBN Method

Initially the JBN method was developed by Johnson et al (1959) as a quick way to calculate the permeability curves of gas and oil in injection experiments. Using the theory developed by Buckley and Leverett, assuming a constant flow rate between the cross-sections and introducing some concepts developed by Welge (1952) to co-relates the fractional flow to the relative permeabilities, it was possible to construct the curves based on the experiments. It is important to highlight that this method does not consider the capillarity and gravitational forces.

Kantzas et al (2016) provide a detailed step-by-step description of the method in 3 main steps:

- The ratio k_{ro} / k_{rw}.
- The values of k_{ro} and k_{rw}.
- The value of Sw.

Initially, the concept of fractional flow can be defined as:

$$f_o = \frac{q_o}{q_t} = \frac{q_o}{q_{Winj}} = \frac{\frac{k_{rO} k A \Delta p}{\mu_O L}}{\frac{k_{rW} k A \Delta p}{\mu_W L}} = \frac{1}{1+\frac{k_{rw}}{k_{ro}}\frac{\mu_o}{\mu_w}} \qquad \text{(Eq 4.3.1.1)}$$

Where k_{rn} is the relative permeability of phase n, and q_{winj} is the total injected water.

Then the authors introduce the concept of injectivty ratio as :

$$I_r = \frac{\Delta p_n}{\Delta p}\frac{1}{q_n} \qquad \text{(Eq 4.3.1.2)}$$

Using the injectivity ratio concept, the relative permeability of oil can be defined as:

$$k_{ro} = f_o \frac{1}{\frac{d\left(1/q_t I_r\right)}{d\left(1/q_i\right)}} \qquad \text{(Eq 4.3.1.3)}$$

Substituting the definitions and preforming some algebraical manipulation is possible to clear correlates the relatives permeabilities of oil and water based on the fractional flow and the fluid dynamic viscosities:

$$k_{rw} = \frac{(1-f_O)}{f_O}\frac{\mu_w}{\mu_o}k_{ro} \qquad \text{(Eq 4.3.1.4)}$$

The authors stated that the Welge method (1952) (used in the JBN solution) was developed with respect to a homogeneous reservoir, not considering possible heterogeneities. The Buckley-Leverett equation was developed for incompressible/immiscible fluids and assumes completely linear displacement and no capillarity effects.

Almutairi et al (2021) state that disregarding capillary pressure results in a wrong relative permeability estimation because wetting and non-wetting phase pressures are assumed to be equal, leading to an error in the calculated permeability for both phases and that the discontinuity in capillary pressure at the outlet of the rock sample cannot be modeled, leading to an error in the saturation calculation.

It is possible to find in the literature authors who proposed adaptations of this method to better reflect reality. Although this method has its limitations, it is by far the most adapted method in the literature, so due to its importance, it was necessary to highlight it here.

4.3.2 Modified JBN Method by Almutairi et al (2021)

Different authors have proposed different adaptations to this method. The main error leading assumptions in the original method is the disregarding of the threshold and critical capillary pressures since these plays important role in producing capillary end effects which cause pore fluids to be non-uniformly distributed within a rock sample (Christiansen and Howarth, 1995).

To address this problem, Almutairi et al (2021) use the same solution as the JBN, incorporating the capillarity pressures as a difference in pressures for drainage experiments. Assuming that the capillarity pressures are equal to the threshold pressures and that the capillarity pressures can be estimated directly from capillarity curves measurements. The solution for the oil phase can be developed as:

$$k_{ro} = \frac{d\left(\frac{1}{t}\right)}{d\left(\frac{\Delta p_o}{t\Delta p_t}\right)} \frac{\mu_o}{\mu_w}(1 - f_w) \qquad \text{(Eq 4.3.2.1)}$$

Where t is the time and :

$$\Delta p_o = \Delta p_{avg} - p_{c,th} \qquad \text{(Eq 4.3.2.2)}$$

Where Δp_o is the difference of pressure of the oil phase, Δp_{avg} is the average difference of pressures and $p_{c,th}$ is the capillarity threshold pressure.

For the aqueous phase, the:

$$\Delta p_w = \Delta p_m - p_{c|x=0} \qquad \text{(Eq 4.3.2.3)}$$

Where $p_{c|x=0}$ is the capillary pressure at the inlet and can be calculated by extrapolation when the outlet water flow is 0, since Δp_w=0 and so Δp_m= $p_{c|x=0}$.

The authors propose that initially the oil and water saturation can be calculated during the material balance test, to determine the capillary pressure threshold at the outlet using the capillary pressure curve to make it possible to calculate the relative oil permeability. After that, the capillary pressure $p_{c|X=0}$ is estimated based on the explained extrapolation, thus making it possible to calculate the relative water permeability data. With the saturation and relative permeability data, it is possible to build the permeability curves, now considering the capillary pressure.

Through a simple experimental manipulation, it is possible to adapt the original method for a better representation. There are several other modifications proposed in the literature that can be adopted depending on the conditions, apparatus constrains and measurement objectives. For this study, the authors emphasize that this method makes the measurements less dependent on the injection rate and that it is easy method to implement and can be used as a first guess of permeability curve to history matching.

4.3.3 Imaging Methods

Eleiri et al (1995) used the same apparatus described in section 4.2.4 to perform unsteady state tests. The author’s idea was to compare the different methods and experimental effects on hysteresis. The tests started with the total saturation of the sample by the described brine, followed by oil injection. The relative permeabilities were calculated by the authors using the JBN method and the rock sample was scanned by the CT scanner after each flow so that through the analysis of the images over time it was possible to calculate the saturation of the phases in the sample for each experiment.

Comparing the tests, the authors were able to conclude that the hysteresis is more evident in the unsteady state tests. The effects of turbulence and viscous instabilities could be observed throughout the experiment, so that the permeability curves obtained can be affected by these instabilities. The residual oil concentration reported for the tests performed in unsteady states were significantly higher than those measured in the steady-state tests, which can also be explained by instabilities in the flow.

5 PERMEABILITY CURVES MODELING AND CALCULATION

In some situations, it is not possible to perform precise laboratory measurements due to the unavailability of laboratory equipment or the absence of time to perform the tests, being necessary to adopt a more generic approach due to the uncertainties involved. Empirical correlations or numerical models capable are often used to estimate permeability curves in those cases. Several authors and companies have dedicated themselves to creating these empirical and numerical models so that there is a wide variety of models available in the literature. This section will be dedicated to evaluating the main methods and used models found in the literature. Kantas et al (2016) cite those defined by Honarpour et al (1982) and Corey and Brooks (1964) as the main ones in the literature.

5.1 Empirical Equations to Calculate the Relative Permeability

5.1.1 Honarpour et al (1982) Empirical Equations

Analyzing the data from real tests from oil and gas fields from different parts of the world under laboratory conditions provided by oil and gas companies, Honarpour et al (1982) decided to adopt a strictly empirical approach to establish equations in water-oil systems and oil-gas systems. Despite the simplistic approach, these equations are commonly adopted in the literature.

For these systems, the following equations were found:

$$k_{rw}^{wo} = 0.03588 \frac{(S_w - S_{wi})}{(1 - S_{wi} - S_{orw})} - 0.01874 \left[\frac{(S_w - S_{orw})}{(1 - S_{wi} - S_{orw}}\right]^{2.9} + 0.56556(S_w^{3.6})(S_w - S_{wi})$$

(Eq 5.1.1)

$$k_{rw}^{wo} = 1.5814 \left(\frac{S_w - S_{wi}}{1 - S_{wi}}\right)^{1.91} - 0.58617 \left(\frac{S_w - S_{orw}}{1 - S_{wi} - S_{orw}}\right)(S_w - S_{wi}) - 1.2484\emptyset(1 - S_{wi})(S_w - S_{wi})$$

(Eq 5.1.2)

$$k_{ro}^{wo} = 0.76067\left[\frac{\left(\frac{S_o}{1-S_{wi}}\right) - S_{orw}}{1-S_{orw}}\right]^{1.8} \cdot \left(\frac{S_o - S_{orw}}{1-S_{wi}-S_{orw}}\right)^{2.0} + 2.6316\emptyset(1-S_{orw}).(S_o - S_{orw})$$

(Eq 5.1.3)

$$k_{ro}^{og} = 0.98372\left(\frac{S_o}{1-S_{wi}}\right)^4\left(\frac{S_o-S_{org}}{1-S_{wi}-S_{org}}\right) \qquad \text{(Eq 5.1.4)}$$

$$k_{rg}^{og} = 1.8655\frac{(S_g-S_{gc})(S_g)}{(1-S_{wi})}k_{rg(Sorg)} + 8.0053\frac{(S_g-S_{gc})(S_{org})^2}{(1-S_{wi})} - 0.2025890(S_g - S_{gc})\left(\frac{1-S_{wi}-S_{org}-S_{gc}}{1-S_{wi}}\right)^2\left(1-\frac{1-S_{wi}-S_{org}-S_{gc}}{1-S_{wi}}\right)^2\left(\frac{k_a}{\emptyset}\right)^{0.5}.$$

(Eq 5.1.5)

Where:

- k_a is the air permeability measured in millidarcies;
- k_o is the oil permeability measured in millidarcies;
- $k_{rg(Sorg)}$ is the gas permeability at the residual oil saturation in millidarcies;
- k_{rg} is the gas relative permeability;
- k_{ro}, is the oil relative permeability;
- k_{rw} is the water relative permeability;
- S_{org} is the residual oil saturation in oil and gas systems;
- S_{orw} is the residual oil saturation in oil and water systems;
- S_w is the water saturation;
- S_{wi} is the irreducible water saturation;
- Φ is the porosity;
- S_g is the gas saturation;
- S_{gc} is the critical gas saturation.

The superscript in the formulas indicates the related system, in such way that og refers to oil-gas systems and wo refers to water-oil systems.

5.1.2 Corey Equations

Considering a theoretical development and based in an isotropic medium and constant pore size, Brooks and Corey (1964) developed the following relationships:

$$k_{rwt} = (S_w^*)^{\frac{2-3\lambda}{\lambda}} \qquad \text{(Eq 5.2.1)}$$

$$k_{rn} = k_r^o \left(\frac{S_m - S_{iw}}{1 - S_{iw}}\right)^2 \left(1 - (S_w^*)^{\frac{2-3\lambda}{\lambda}}\right) \qquad \text{(Eq 5.2.2)}$$

$$S_w^* = \left(\frac{S_w - S_{iw}}{1 - S_{iw}}\right) \qquad \text{(Eq 5.2.3)}$$

$$k_r^o = 1.31 - 2.62 S_{iw} - 1.1 (S_{iw})^2 \quad \text{(Eq 5.2.4)}$$

Where:

- k_{rwt} is the wetting phase relative permeability;
- k_{rn} is non-wetting phase relative permeability;
- S_w is the water saturation;
- k_r is non-wetting phase relative permeability at the irreducible saturation of the wetting phase;
- S_{iw} is the system's initial water saturation;
- S_{w^*} is a normalized wetting phase saturation value, calculated by auxiliary equations
- λ pore size distribution index, determined by auxiliaries equations, and;
- S_m is equals to 1 minus the residual oil saturation.

5.2 Numerical Models

With the development of technology and the expansion of computational processing power, different authors have dedicated themselves to developing numerical methods capable of building permeability curves based on the most diverse factors and field and laboratory data.

The first authors to adopt this numerical approach to relative permeability calculations were Sigmund and McCaffery (1979), when proposed that relative-permeability curves for a variety of rock types could be expressed in terms of two adjustable parameters and their standard error estimates. The authors proposed the use of a reservoir simulator for interpreting laboratory waterflood data and concluded that the curves obtained with the analysis applying the least squares method to the simulated data can be widely used for reservoir studies, accurately describing the flow dynamics. in situ. Since then, several authors have endeavored to develop numerical methods capable of representing the permeability curves.

An interesting application of these methods is that models developed using production data can be considered representative at the reservoir level, which is an interesting approach when there is an accurate history of field data.

5.2.1 Two-Phase Relative Permeability by a Linear Regression Model

Lederer (2022) defines linear regression as a method that relates predictor outcome variables assuming linearity in the relationships, noting that algebraic tricks can be adopted to linearize the problems to make the model more representative.

Ibrahim and Koederitz (2000) used 416 sets of relative permeability data from steady-state or unsteady-state experiments with natural rocks samples available in the literature or provided by the industry, to, through a linear regression model, develop 24 equations representative for different reservoir and rock wettability conditions through a linear regression method.

The authors adopted a methodological approach to normalize the saturation data of each phase considering the data of irreducible water saturation and critical hydrocarbon saturations to plot all curves in the same range of normalized data. Thus, data could be plotted, and relationships could be adopted. To quantify the correlation of the data, the authors used the coefficient of multiple determination, which measures the degree of linearity of the plotted data. When the coefficient is equal to 1, the data are presented in a completely linear way and when equal to 0, a total nonlinear relationship is found between the data. For the purposes of building the final equations, multiple determination coefficient data above 0.6 were considered satisfactory and this data set was used.

The authors also compare the results obtained with the correlations empirically developed by Honarpour et al (1982) and concluded that the curves obtained were consistent with the developed models, being capable of estimate the permeability curves for conditions characterized by distinct wettability, which was not is considered by the Honarpour model.

As much as it is a simplistic approach, the results showed an efficient model to be used for oil-water and oil-gas systems, being an alternative when there is a large database available the literature.

5.2.2 Uses of Artificial Intelligence (AI) for Permeability Curves

Naturally, the consideration of several parameters in the computational models ends up increasing the complexity of the problems and the time required for computational processing to solve these problems. The adoption of a methodological approach, as well as the use of optimization algorithms, can help to achieve a more accurate result.

A recent approach to solving highly complex problems that has been widely used by various fields of science is the use of artificial intelligence. Kok et al (2002) defines artificial intelligence as an area of study in computer science that focuses on developing computational methods capable of simulating human capacities for learning, adapting, self-correcting and creating correlations through programming techniques.

Solanski et al (2021) provide a general review of the application of artificial intelligence techniques in the oil and gas sector, listing the main references and methods used to predict permeability curves. Among which we can highlight:

- Use of well log data from petroleum reservoirs to predict the permeability using fuzzy logic;

• Use of well log data in neural network capability of predicting accurately permeability curves;

• Use of the Multi-Gene Genetic Programming (MGGP) method to predict permeability in heterogeneous oil reservoirs;

• The use of a genetic algorithm, forward and backward stepwise algorithm to predict accurate oil/water relative permeability curves;

The use of neural networks also stands out as a plausible alternative for solving these highly complex problems and has recently been a widely used alternative for solving complex problems in petroleum engineering.

Hecht-Nielsen (1989) define the neural network as a parallel, distributed information processing structure of processing elements (together with unidirectional signal channels called connections. Each processing element has a single output connection which branches ("fans out") into as many collateral connections as desired (each carrying the same signal - the processing element output signal). The processing element output signal can be of any mathematical type desired, so that through a defined algorithm it is possible to use these networks to arrive at representative models of reality.

Spada et al (2020) developed a methodology to determine and validated the relative permeability curves using a feedforward artificial neural network modeling for the oil reservoir proposed. Initially the authors generated randomly 200 permeability curves using the Corey equations. The generated curves were used as inputs to a reservoir simulator to obtain simulated production data. The generated data were then introduced into a neural network with programmed training to store the scenarios according to a set value of normalized mean square error. The generated data were then compared to historical production data to validate the method so that the oil yield and gas-hi-ratio data obtained very close values while the well pressure and water production data. showed significant errors. The authors emphasize that to reduce these errors, it would be necessary to apply filters to adjust the simulation parameters. The work highlights the possibility of using neural networks for the creation and validation of permeability curves, showing an alternative for when there is availability of computational resources and historical production data.

Benson et al (2015) also produced numerical simulations were carried out for steady-state and unsteady state measurements over a 4 wide range of conditions in CO2-Brine systems so that the results obtained were similar to those obtained experimentally, evidencing the possibility of developing of numerical methods for permeability curves in CCS projects.

6 DISCUSSION POINTS

6.1 The Permeability Curves Measurements

Initially, it was possible to find conflicting studies on the effects of cleaning the samples on the permeability curves, so that some authors defend that some cleaning methods can change the initial wettability of the sample, directly influencing the results, while some authors claim that in specific cleaning techniques, no such changes in wettability were observed. In any case, the API (American Petroleum Institute) lists good practices for performing core cleaning, which can and should be followed for a consistent comparison of results from diverse sources. It is recommended, when possible, at least one measurement with the sample in its natural state so that the effects of cleaning on the final results can be quantified, study by study.

Several authors have reported that Steady-State techniques allow a more precise and accurate result, given the reduction of the possibility of turbulence effects in the flow, however, they demand a prolonged period for their accomplishment, so that sometimes their use is not viable. Eleri et al (1995) showed that such techniques can lead to unnatural values of the critical saturations of hydrocarbons, which leads to the belief that the time of exposure to fluids during the test can cause changes in the wettability of the samples, still showing the method capable of better characterizing the samples. Through the literary review, it is possible to affirm that most of the developed works use adaptations of the “Penn State Method” regarding variations in pressure, temperature or even the presence of 3 types of fluids, according to the needs of each study.

As for Unsteady State Methods, it is evident that they allow a faster and commercially viable analysis when there is a need to evaluate several samples, presenting, however, less accurate results and the greater presence of hysteresis. The tests usually consider simplifications, disregarding capillary, and gravitational forces; however, it is possible to find adaptations in the literature allowing the correction in scenarios where these forces cannot be neglected. The most used and adapted method for conducting these experiments is the JBN developed by Johnson et al (1959).

Both steady-state and non-steady-state tests can be performed under laboratory and reservoir conditions using commercially available laboratory apparatus.

Imaging techniques allow obtaining extremely accurate images while performing both types of tests. The precision offered by this type of technique allows the precise mapping of the flow evolution and the saturations of the phases during the experiment. This technique allows the precise comparison of the types of tests, being a powerful tool for comparative studies and for the precise characterization of the evolution of the multiphase flow in the porous medium, describing it in detail for each test type. The high cost involving with the acquisition and adaptation of a CT-scanner, the danger in using radiation and radioactive isotopes and the impossibility to perform the measurements in reservoir condition are disadvantages of this type of technique.

6.2 Permeability Curves Models

The main empirical correlations that can be found in the literature are the Honapour and Corey relationships. These relationships take an empirical approach and do not distinguish system characteristics such as rock wettability, yet they provide an estimation when sample or field data are scarce.

The use of numerical and computational models capable of processing a large amount of data has been a great field of research in recent years. Linearization models that consider a large amount of data produced by the literature over the years have proved to be effective for creating specific equations for distinct types of wettability and similar approaches can be developed to analyze specific rock types and systems.

Several computational models based on the use of artificial intelligence have been developed, especially in the last 15 years, capable of creating permeability curves from the most different data available. These models are effective when there is considerable computing power and a large amount of data available. Methods such as the one developed by Spada et al (2020) from the generation of random scenarios and validation from historical production data, prove to be an interesting alternative for more classical applications of permeability curves in reservoir simulations. However, due to the historical lack of data related to geological carbon capture projects, the application of these methods is premature, being an alternative for a medium-term future.

The literature is scarce in providing specific empirical and numerical models for CO2-Brine systems, so it is necessary to evaluate the accuracy in the application of the models routinely adopted in systems with oil as well as adaptations for CCS projects.

7 CONCLUSION

Through the analysis of the works described here, it is evident that the choice of the type of measurements or models adopted to obtain and apply the permeability curves will depend on the availability of time, financial and computational resources, available data, in addition to the naturally imposed conditions, as well as the fluids involved in the study and the wettability of the studied rocks. However as general recommendations we set the following guidelines:

Based on the possibility of changing permeability by the sample cleaning process, it is recommended that for every study at least one measurement is taken before the cleaning process with the sample in its natural state, for comparative purposes. In any case, for sample cleaning processes, it is recommended to use the methods described by the American Petroleum Institute.

For cases in which there is no and there is a need for a precise characterization of the permeability curves, the use of tests in steady state is recommended. It is necessary to consider that the time of exposure of the sample to the test can be large enough to change its wettability.

For comparative studies to validate the use of one of the methods, as well as the quantification of the magnitude of the differences in the final results and hysteresis, the use of imaging techniques is recommended.

For practical applications, in which there is no initial database on permeability curves, the possibility of using empirical relationships and equations obtained by Ibrahim and Koederitz (2000) is presented. However this method requires a preliminary characterization of the sample's wettability.

When there is a large data history in relation to the production data of a field or well, the use of numerical methods through the generation of scenarios by computer simulation and the validation of these data through comparison with reality, is an alternative.

Literature currently does not provide many specific studies on permeability curves for CO_2-Brine systems, so the methods described in this work provide support for future studies. Once permeability curves are experimentally produced in CO_2-Brine systems in a sufficiently considerable number, the models described in this work support the development of numerical and empirical relationships capable of mathematically expressing the permeability curves.

7.1 Future Works Recomendation

To Understand the importance of permeability curves, especially in gas-brine systems, for the development of CCS projects, the following studies are recommended:

- Conduct a study to validate or discart the application of empirical and numerical equations found in the literature in order to validate their application for gas-water systems.
- To carry out a comparative study between the unsteady state and steady state methods in gas-water systems using imaging in order to characterize the main differences in the results. In this scenario, it is not possible to perform the experiments in reservoir condition.
- Conduct a series of experimental measurements of permeability curves in gas-brine systems considering the wettability of the samples and to develop database to serve as a basis for empirical and numerical models of permeability curves.

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