

# Review properties on reservoir rock for effective production

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## **Abstract**

Porosity and permeability are fundamental rock properties. Porosity is a measure of the storage capacity of the rock and permeability is a measure of rock flow capacity. Storage capacity tells us how much resource can be contained in the rock, and flow capacity tells us how fast one can produce the resource. Pore volume compression coincided with extensive oil and water production and corresponding pressure reduction in producing formations. Pore spaces in reservoir rock are occupied by fluid phases, including oil, water, and gas phases. Darcy found that flow rate is proportional to the pressure change between the inlet and outlet of the porous medium. Pore pressure decreases in the formation as fluid is withdrawn from the formation during production. The chapter considers the features of permeability heterogeneity. Layer inclination depends on the local depositional environment and geological events such as folding and tectonic activity. In the current work the properties of reservoir has been effectively reported, which could be the main parameters for assessing the potential of inflow.

## **Introduction**

According to Society of Petroleum Engineers Glossary, a reservoir rock is a rock containing porosity, permeability, sufficient hydrocarbon accumulation and a sealing mechanism to form a reservoir from which commercial flows of hydrocarbons can be produced. Porosity and permeability are the reservoir rock most significant physical properties. A fundamental property of a reservoir rock between them is porosity. However, for explorationists, an effective reservoir rock, the most fundamental reservoir rock property is its permeability. Both of them are geometric properties are the result of its lithological, structural and

compositional behavior (composition). These physical compositions of a rock and the textural properties are geometric such as sizes and shapes of the rock grains, their arrangement system and packaging. The efficiency of reservoir rock account on different important properties, however in this paper discussing on reservoir rocks properties, porosity and permeability are main topics to focus on. petroleum system is made of different elements which encompass reservoir rock. Moreover, it is found in a sedimentary basin whereby explorationists are able to study its stratigraphy and its sedimentology (rock history) to determine if there is a likeliness of the existence of petroleum system. After they (explorationists) come up with concluding the existence of a petroleum system, they go for further scientific tests-collecting different data and analyzing them to be able to decide about drilling and completion of a petroleum system. Significant part of their scientific studies on particular petroleum system is on estimating the possible quantity of hydrocarbons (crude oil) that may be present there. The reservoir content is estimated by means studying rock properties which can be determined in a direct way or indirectly. The indirect are done through laboratory measurements on core samples of reservoir rock of interest which constitutes direct methods of porosity data acquisition. This is done by measuring a bulk and their pore (empty spaces in a rock). Its bulk volume is gravimetrically determined when a core-sample is having an irregular shape. A petroleum system may have one or more reservoir rocks, and reservoir rocks may have different property basing on their types. Types of reservoir rock depend on kinds of their contents, composition, morphology and sedimentology.

### ***Research Methodology***

There are few fundamental types of properties of a hydrocarbon reservoir that control its initial contents, behavior, production potential, and hence its reserves.

The rock properties of porosity, and permeability, which are dependent on solid grain/particle arrangements and packing.

The wettability properties, capillary pressure, phase saturation, and relative permeability, which are dependent on interfacial forces between the solid and the water and hydrocarbon phases.

## Porosity

Porous rock is the essential feature of hydrocarbon reservoirs. Oil or gas (or both) is generated from source layers, migrates upwards by displacing water and is trapped by overlying layers that will not allow hydrocarbons to move further upwards. Porous material in hydrocarbon reservoirs can be divided into clastics and carbonates. Clastics such as sandstone are composed of small grains normally deposited in riverbeds over long periods of time and covered and compressed over geological periods. Carbonates (various calcium carbonate minerals) are typically generated by biological processes and again compressed by overlying material over long periods of time. Roughly 60% of conventional oil and gas resources occur in clastics and 40% in carbonates.

Porosity, given the symbol  $\phi$ , is defined as the ratio of void volume to total rock volume:

= void volume/ (grain + void volume)

$$\phi = \frac{V_p}{V_b}$$

Where,

$V_p$  = pore space volume and

$V_b$  = bulk volume (grain + void volume).

## Permeability

Permeability is a property of the porous medium that measures the capacity and ability of the formation to transmit fluids. The rock permeability,  $k$ , is a very important rock property

because it controls the directional movement and the flow rate of the reservoir fluids in the formation.

Darcy developed a fluid flow equation that has since become one of the standard mathematical tools of the petroleum engineer. If a horizontal linear flow of an incompressible fluid is established through a core sample of length  $L$  and a cross-section of area  $A$ , then the governing fluid flow equation is defined as

$$q = - \frac{kA}{\mu} \frac{dp}{dL}$$

Where,

$k$  = proportionality constant, or permeability, Darcy  
 $\mu$  = viscosity of the flowing fluid, cp

$dp/dL$  = pressure drop per unit length, atm/cm

$q$  = flow rate through the porous medium, cm<sup>3</sup>/sec

$A$  = cross-sectional area across which flow occurs, cm<sup>2</sup>

## Relative Permeability

In multiphase flow in porous media, the relative permeability of a phase is a dimensionless measure of the effective permeability of that phase. It is the ratio of the effective permeability of that phase to the absolute permeability.

**Two Phase Relative Permeability:** When a wetting and a

non-wetting phase flow together in a reservoir rock, each phase follows separate and distinct paths. The distribution of the two phases according to their wetting characteristics results in characteristic wetting and non-wetting phase relative permeabilities.

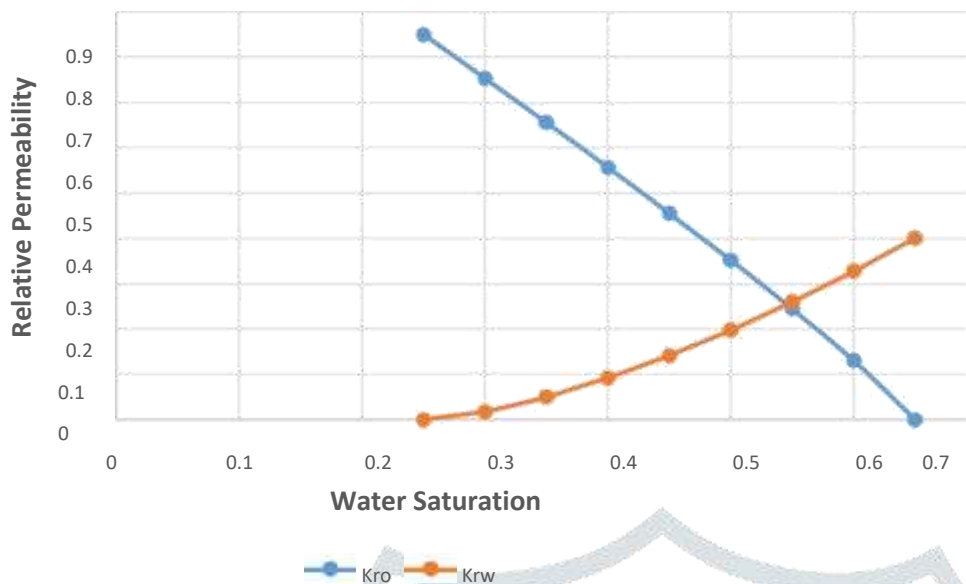
### Calculation of Relative Permeability with Corey's Method: Oil Water System:

$$k_{ro} = (k_{ro})_{S_{wc}} \left[ \frac{1 - S_w - S_{orw}}{1 - S_{wc} - S_{orw}} \right]^{n_o}$$

$$k_{rw} = (k_{rw})_{S_{orw}} \left[ \frac{S_w - S_{wc}}{1 - S_{wc} - S_{orw}} \right]^{n_w}$$

#### Input Data:

$(k_{ro})_{S_{gc}}$	: 0.6	$(k_{rg})_{S_{wc}}$	: 0.95
$S_{wc}$	: 0.25	$(k_{rw})_{S_{orw}}$	: 0.4
$S_{org}$	: 0.23	$(k_{ro})_{S_{wc}}$	: 0.85
$S_{gc}$	: 0.05	$p_c(S_{wc})$	: 20
$S_{orw}$	: 0.35	$p_c(S_{lc})$	: 30
$n_o$	: 0.9	$n$	: 1.2
$n_w$	: 1.5	$n_p$	: 0.71
$n_g$	: 0.6	$n_{pg}$	: 0.51



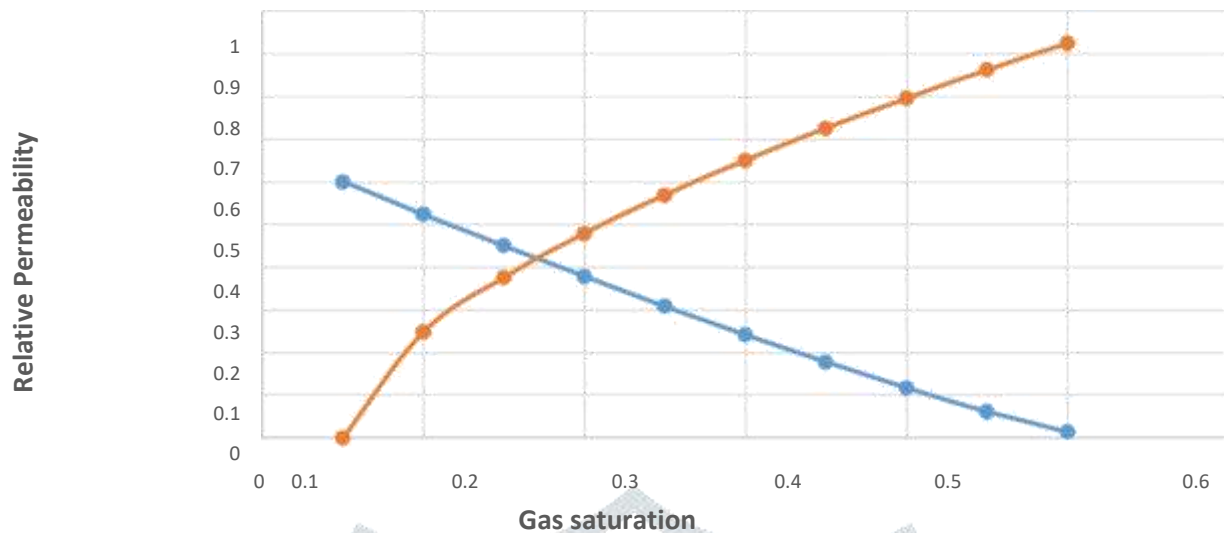
Plot 1: Oil Water Relative Permeability Curve

In an oil water system during production saturation of water increases and oil saturation decreases. The wetting phase relative permeability curve  $K_{rw}$  starts from  $S_{wc}$  i.e. connate water saturation and move towards 100% water saturation. The non-wetting phase relative permeability curve begins with 100% liquid saturation and move towards residual oil saturation.

### Gas Oil System:

$$k_{ro} = (k_{ro})_{S_{gc}} \left[ \frac{1 - S_g - S_{lc}}{1 - S_{gc} - S_{lc}} \right]^{n_{go}}$$

$$k_{rg} = (k_{rg})_{S_{wc}} \left[ \frac{S_g - S_{gc}}{1 - S_{lc} - S_{gc}} \right]^{n_g}$$



Plot 2: Gas Oil Relative Permeability Curve

In a gas oil system during production oil saturation decreases. The wetting phase relative permeability curve  $K_{ro}$  starts from 100% liquid saturation and move towards  $(S_{wc}+S_{or})$  i.e. sum of connate water saturation & Residual oil saturation The non-wetting phase relative permeability curve begins with critical gas saturation  $S_{gc}$  and move towards residual liquid saturation.

Where,

$k_{ro}$  = relative permeability to oil

$k_{rg}$  = relative permeability to gas

$k_{rw}$  = relative permeability to water

$S_{lc}$  = total critical liquid saturation

$(k_{ro})_{S_{wc}}$  = oil relative permeability at connate water saturation

$(k_{ro})_{S_{gc}}$  = oil relative permeability at critical gas saturation

$(k_{rg})_{S_{wc}}$  = gas relative permeability at connate water saturation

$S_{orw}$  = residual oil saturation in the water-oil system

$S_{org}$  = residual oil saturation in the gas-oil system  $S_{gc}$  = critical gas saturation

$(k_{rw})_{Sorw}$  = water relative permeability at the residual oil saturation  $n_o, n_w, n_g, n_{go}$  = exponents on relative permeability curves  $p_{cwo}$  = capillary pressure of water-oil systems

$p_c(S_{wc})$  = capillary pressure at connate water saturation

$n_p$  = exponent of the capillary pressure curve for the oil-water system  $p_{cgo}$  = capillary pressure of gas-oil system

$n_{pg}$  = exponent of the capillary pressure curve in gas-oil system  $p_c(S_{lc})$  = capillary pressure at critical liquid saturation.  $S_{gc}$  = critical gas saturation

$S_{wc}$  = connate water saturation

$S_w$  = water saturation

**Three Phase Relative Permeability:** The relative

permeability to a fluid is defined as the ratio of effective permeability at a given saturation of that fluid to the absolute permeability at 100% saturation.

**Calculation of Relative Permeability with Stone's Model II:**

$$k_{ro} = (k_{ro})_{S_{wc}} \left[ \left( \frac{k_{row}}{(k_{ro})_{S_{wc}}} + k_{rw} \right) \left( \frac{k_{rog}}{(k_{ro})_{S_{wc}}} + k_{rg} \right) - (k_{rw} + k_{rg}) \right]$$



Where,  
 $k_{ro}$  = three- phase relative permeability

## Wettability

When two immiscible fluids are in contact with a solid surface, one will tend to spread over or adhere to the solid more than the other. This is the result of a balance of intermolecular forces and surface energies between fluids and the solid .Where vector forces are balanced at the oil – water - solid contact point, giving the relationship

$$\sigma_{os} - \sigma_{ws} = \sigma_{ow} \cos \Theta_c$$

Where,

$\sigma_{os}$  = the interfacial tension between oil and solid ;

$\sigma_{ws}$  = the interfacial tension between water and solid ;

$\sigma_{ow}$  = the interfacial tension between oil and water ; and

$\Theta_c$  = the contact angle between water and oil at the contact point measured through the water.

Wettability will control the distribution of oil and water in the pore space. In water wet systems oil will tend to be found in the centers of pores, while in oil wet systems oil will be retained around the solid grains. This will of course have a fundamental effect on oil recovery in water flooding. Gas will normally be the non-wetting phase with respect to both water and oi

## Surface & Interfacial Tension

In dealing with multiphase systems, it is necessary to consider the effect of the forces at the interface when two immiscible fluids are in contact. When these two fluids are liquid and

gas, the term surface tension is used to describe the forces acting on the interface. When the interface is between two liquids, the acting forces are called interfacial tension.

The surface or interfacial tension has the units of force per unit of length, e.g., dynes/cm, and is usually denoted by the symbol  $\sigma$ .

## Capillary Pressure

When two immiscible fluids are in contact, a discontinuity in pressure exists between the two fluids, which depends upon the curvature of the interface separating the fluids. We call this pressure difference the capillary pressure and it is referred to by  $p_c$ .

Denoting the pressure in the wetting fluid by  $p_w$  and that in the non-wetting fluid by  $p_{nw}$ , the capillary pressure can be expressed as:

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

$$p_c = p_{nw} - p_w.$$

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

There are three types of capillary pressure:

Water-oil capillary pressure (denoted as  $p_{cwo}$ )  $p_{cwo} = p_o - p_w$

Gas-oil capillary pressure (denoted as  $p_{cgo}$ )

$$p_{cgo} = p_g - p_o$$

Gas-water capillary pressure (denoted as  $p_{cgw}$ )  $p_{cgw} = p_g - p_w$

Where,

$p_g$  = pressure of gas

$p_o$  = pressure of oil

$p_w$  = pressure of water

If all the three phases are continuous, then:

$$p_{cgw} = p_{cgo} + p_{cwo}$$

In an oil water system during production saturation of water increases and capillary decreases simultaneously as it is a function of pressure and saturation. The capillary pressure curve  $p_c$ , which is the pressure difference between wetting phase and non-wetting phase, starts from  $S_{wc}$  i.e. connate water saturation and move towards maximum water saturation i.e. (1- residual oil saturation).

### Saturation

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

$$\text{fluid saturation} = \frac{\text{total volume of the fluid}}{\text{pore volume}}$$

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

$$S_o = \frac{\text{volume of oil}}{\text{pore volume}}$$

$$S_g = \frac{\text{volume of gas}}{\text{pore volume}}$$

$$S_w = \frac{\text{volume of water}}{\text{pore volume}}$$

Where,

$S_o$  = oil saturation

$S_g$  = gas saturation

$S_w$  = water saturation

Thus, all saturation values are based on pore volume and not on the gross reservoir volume. The saturation of each individual phase ranges between zero to 100 percent. By definition, the sum of the saturations is 100%, therefore:

$$S_g + S_o + S_w = 1.0$$

The fluids in most reservoirs are believed to have reached a state of equilibrium and, therefore, will have become separated according to their fluid saturation.

## Conclusion

The material of which a petroleum reservoir rock may be composed can range from very loose and unconsolidated sand to a very hard and dense sandstone, limestone, or dolomite. The grains may be bonded together with a number of materials, the most common of which are silica, calcite, or clay. Knowledge of the physical properties of the rock and the existing interaction between the hydrocarbon system and the formation is essential in understanding and evaluating the performance of a given reservoir. Rock properties are determined by performing laboratory analyses on cores from the reservoir to be evaluated. The cores are removed from the reservoir environment, with subsequent changes in the core bulk volume, pore volume, reservoir fluid saturations, and, sometimes, formation wettability. The effect of these changes on rock properties may range from negligible to substantial, depending on characteristics of the formation and property of interest, and should be evaluated in the testing program.

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