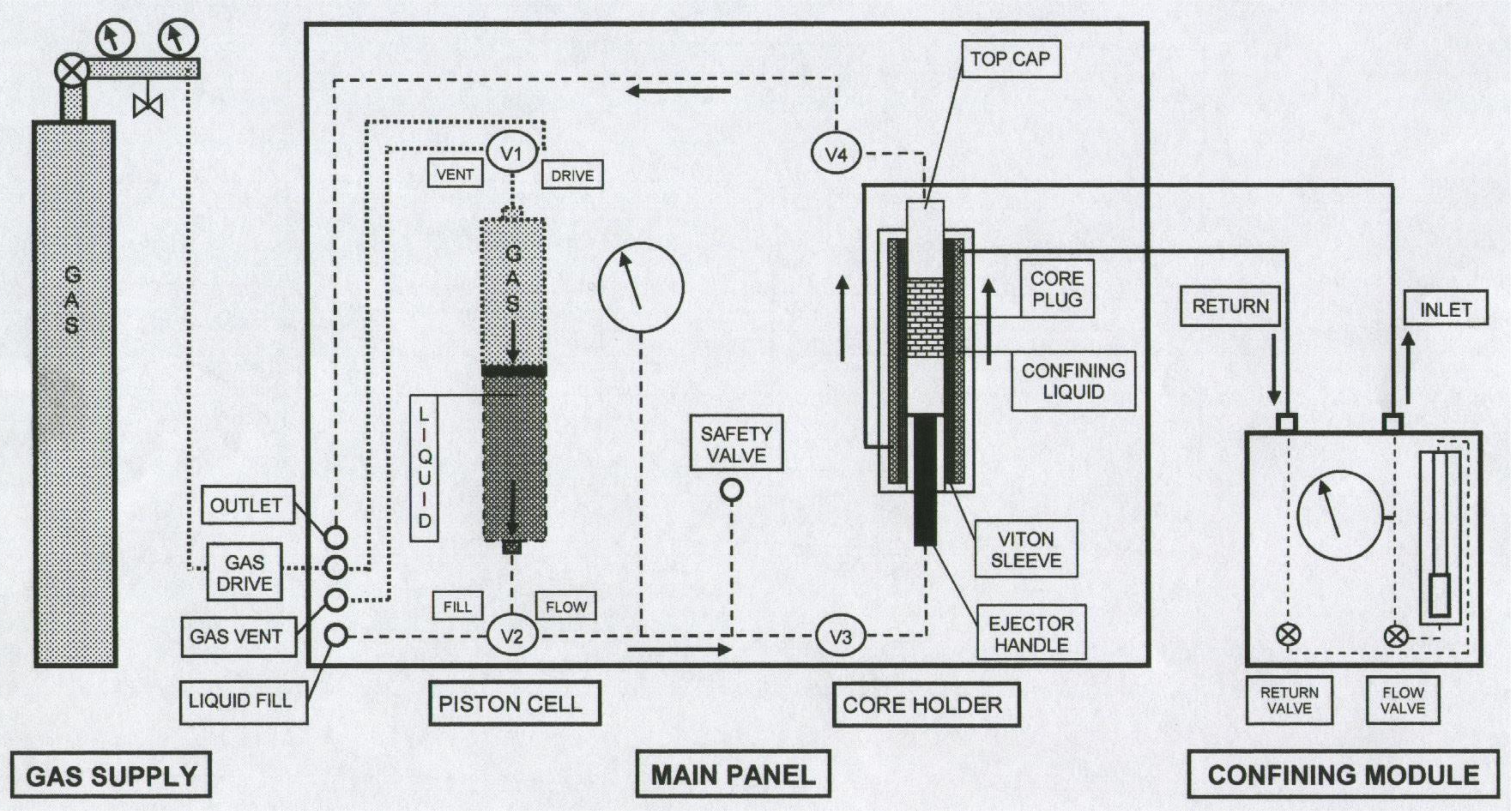
Permeability Measurement

Core Analysis Lab

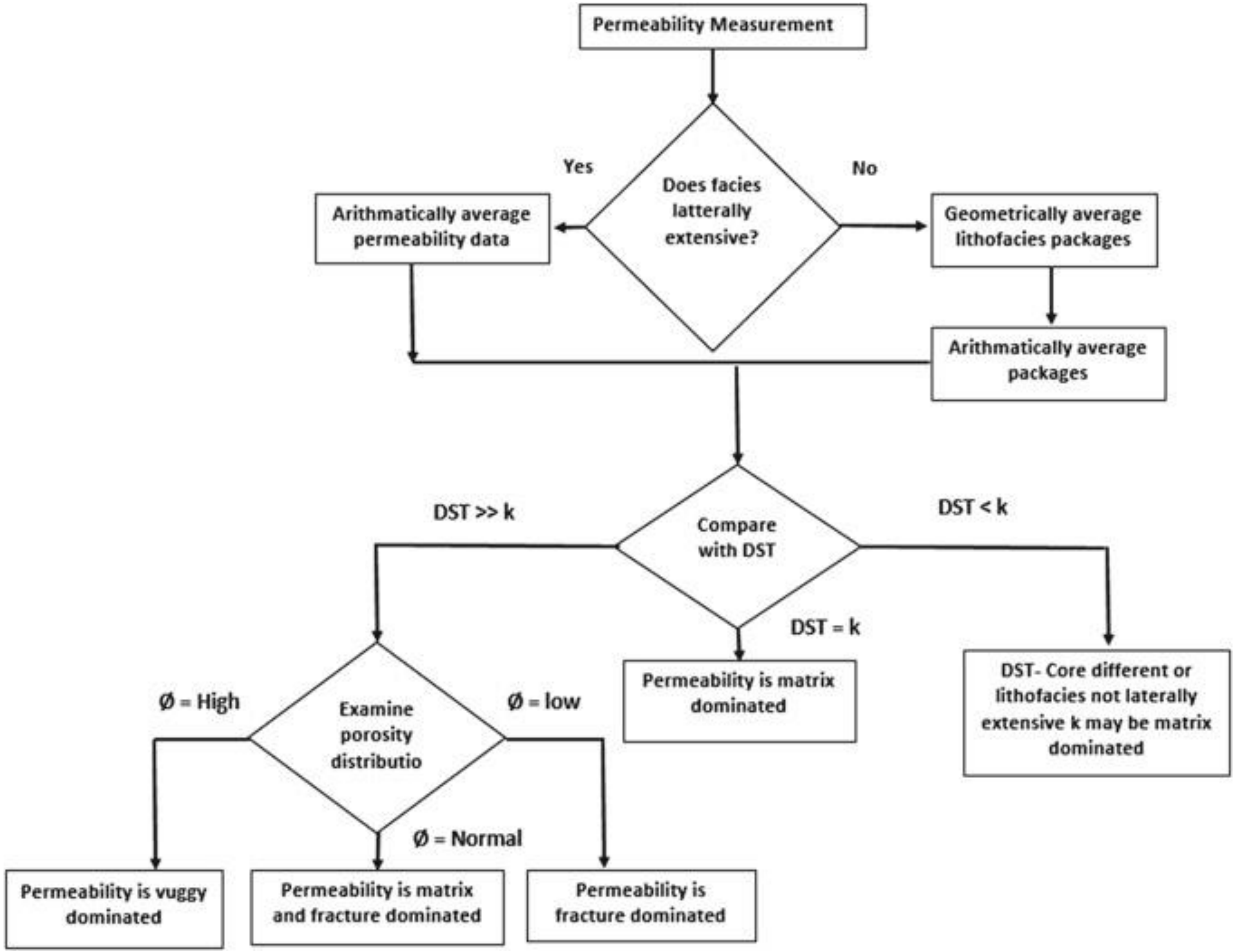
Liquid Permeameter – Injection System



Laboratory Determination of Permeability

Darcy presented an experimental equation which is describing the fluid flow in porous media as a function of pressure gradient and gravitation. Absolute permeability of Single-phase flow is measured on core sample inside a steel cylinder depicted

$$Q = A\left(\frac{K}{\mu}\right)\left(\frac{\Delta P}{L}\right)$$


Permeability Measurement
Does facies latterally extensive?
Yes
No
Arithmatically average permeability data
Geometrically average lithofacies packages
Arithmatically average packages
Compare with DST
DST >> k
DST < k
DST = k
Permeability is matrix dominated
DST- Core different or lithofacies not laterally extensive k may be matrix dominated
Examine porosity distributio
Ø = High
Ø = low
Ø = Normal
Permeability is vuggy dominated
Permeability is matrix and fracture dominated
Permeability is fracture dominated

Klinkenberg noticed that the permeability of the core sample is not constant by using gases as a test fluid. Klinkenberg effect is very important at laboratory scale only, because the permeability is normally determined at low pressures. The following formula is defining the gas permeability (kg) at the mean pressure (Pm) and liquid permeability (kL)

$$K_g = K_L\left(1 + \frac{b}{P}\right)$$

where the coefficient b is obtained experimentally and relies on both, rock aperture size and the type of gas used. It proposes that a scheme of gas permeability versus mean pressure (1/Pm) is a straight line., once the mean pressure raises, the permeability comes close to the liquid permeability. Therefore, regardless of the type of gas used, the same permeability to liquid is obtained for a given rock sample.

Absolute Permeability Correlations

The capillary pressure measurement used to estimate the connate water saturation of varying permeability from a core sample deliver a good accuracy. Therefore, it's achievable to correlate connate water content with the core sample permeability in a particular reservoir to a certain distance. The complication of the relationship between pore geometry and permeability has determined in many studies. No relationship connecting the two parameters has been proved yet. As an alternative, there are overabundance correlations for calculating permeability. The following are the two empirical approaches are widely used to determine the permeability using connate water saturation and porosity parameter.

The Timur Equation

Timur (1968) suggested the below equation to estimate the permeability as a function of connate water saturation and porosity, and the equation can only be applied in hydrocarbon-bearing zones

$$K = 8.58102\left(\frac{\O^{4.4}}{Swc^{2}}\right)$$

The Morris-Biggs Equation
Morris and Biggs (1967) proposed the below two equations to estimate the permeability of both oil and gas reservoirs.

For oil reservoir

$$K = 62.5\left(\frac{\emptyset^3}{Swc}\right)^2$$

For gas reservoir

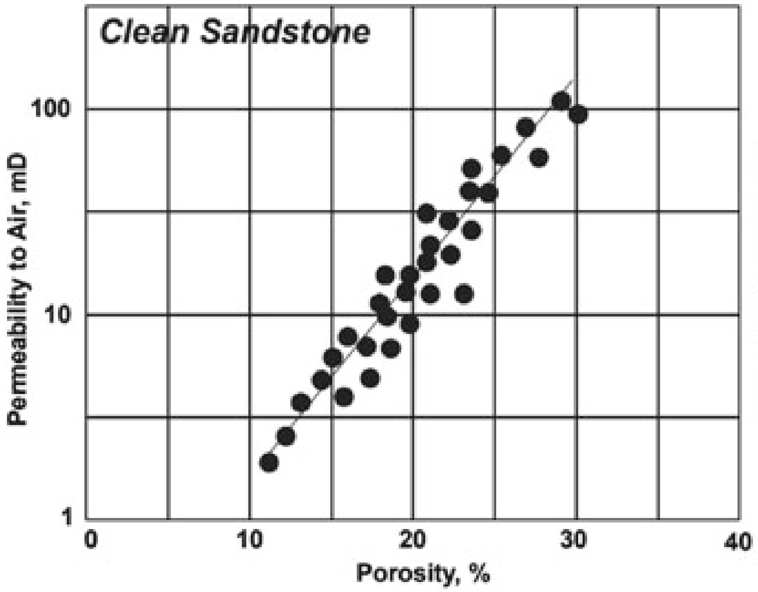
$$K = 2.5\left(\frac{\emptyset^3}{Swc}\right)^2$$

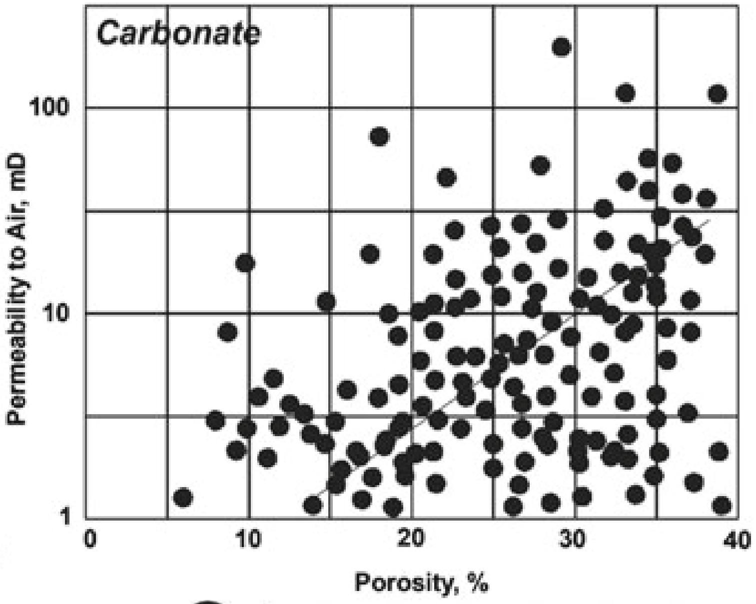
Where ϕe is effective porosity as a bulk volume fraction, k is absolute permeability in millidarcies, and Sw is effective water saturation above the transition zone

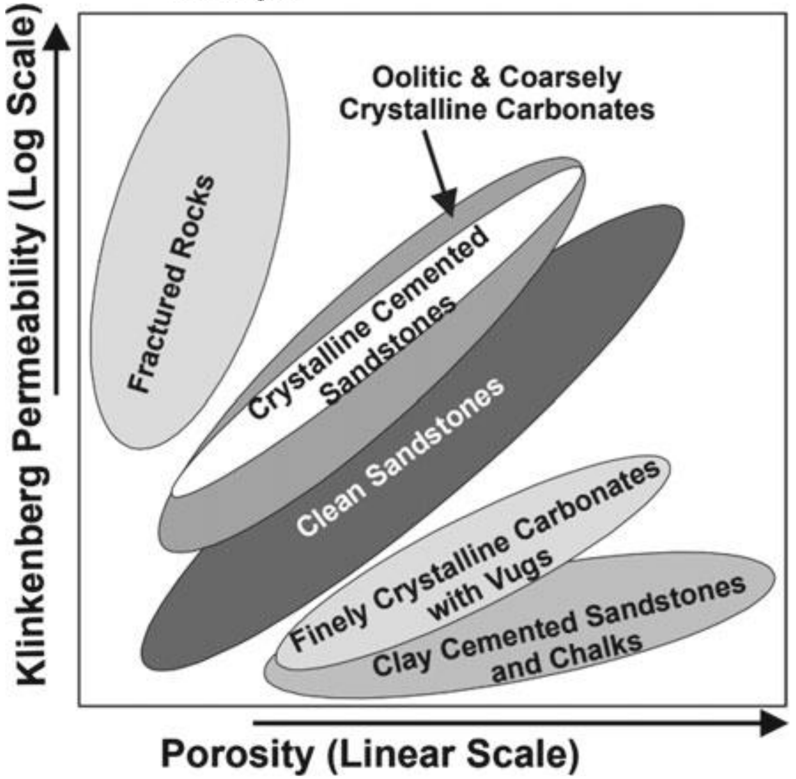
PoroPerm Relationships

Permeability is of paramount importance to the hydrocarbon industry because it defines the viability of the fluids that can be extracted from reservoir rock. The most effective parameter on permeability is porosity. Naturally, higher porosities mean there are many fairways for fluid to flow. One of the important practices that are used to permeability data is to plot it on a logarithmic scale poroperm cross-plot diagram below.

To obtain better results, poroperm cross-plots need to be plotted for clearly defined reservoir zones. In the same time, Poroperm plot for different reservoir rocks can be constructed together on the same plot, and form a map of poroperm relationships, as shown in the below figure. This plot would be time consumed to identify all reservoir rock units, but the interpretation can be made. Normally, there is a sort of relationship within a specific rock unit and the variations between rock units which might be important in the reservoir rock analysis. The main purposes of the poroperm crossplot are to predict the permeability when the porosity data is available only and to create a porosity cut-off. The plotted data on the below figuers, as an example, shows the permeability of the sandstone is very well controlled by the porosity, while the carbonate plot displays more scattering data showing that the porosity has an effect, but there are other main factors governing the permeability. Commonly, some carbonates reservoirs have high porosities and low permeabilities; this is because there is no interconnecting between the effective porosity (vugs or cavity) of the reservoir.


Clean Sandstone
Permeability to Air, mD
100
10
1
0
10
20
30
40
Porosity, %


Carbonate
Permeability to Air, mD
100
10
1
0
10
20
30
40
Porosity, %


Klinkenberg Permeability (Log Scale)
Porosity (Linear Scale)
Fractured Rocks
Oolitic & Coarsely Crystalline Carbonates
Crystalline Cemented Sandstones
Clean Sandstones
Finely Crystalline Carbonates with Vugs
Clay Cemented Sandstones and Chalks

Estimating Permeability Based on Kozeny-Carman Equation

The Carman-Kozeny equation has been used to calculate permeability (k). The equation derived from the combination of Darcy's and Poiseuille's laws. Whereas Darcy's formula macroscopically measures fluid flow, Poiseuille's formula defines the parabolic movement of a viscous fluid in a straight-circular tube.
The Kozeny-Carman equation is proposed as a permeability function of porosity, grain size, and tortuosity (Kozeny 1927). The equation is normally applied to determine fluid pressure drop in pores media that includes consolidated sand grains.

Equation is applicable to calculate permeability models for a particular single-phase flow. As the Kozeny equation is applied to estimate permeability development versus porosity, the particle size and tortuosity are kept constant. Usually, the Kozeny equation relates the absolute permeability k_A (mD) to porosity Ø (fraction) and grain size d (mm) as below equation:

$$kA \sim d2\ Ø3$$

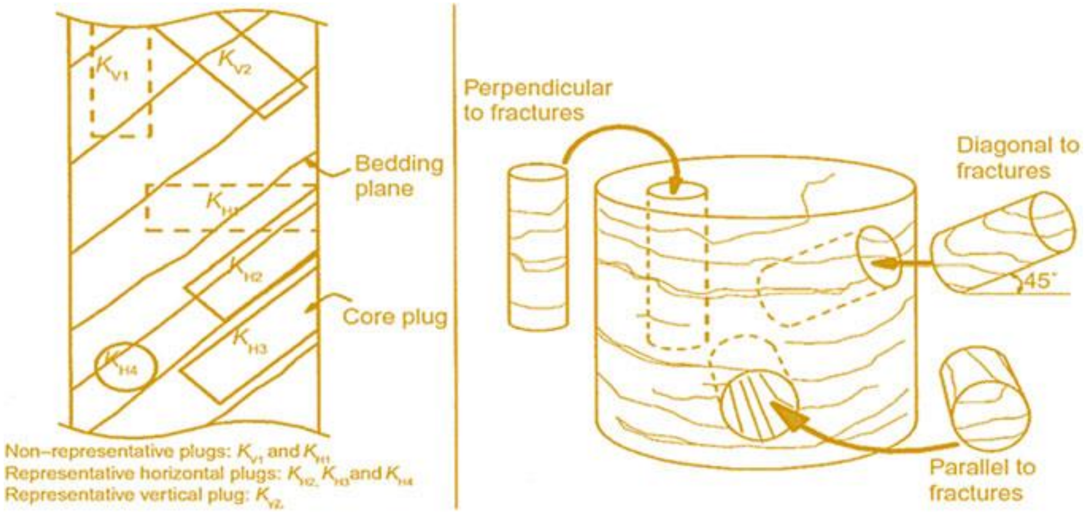
This relation is often applied to simulate permeability versus porosity development in datasets. Therefore, in the calculations, the grain size d is usually held constant. The following is the single-phase Kozeny equation

$$K = a \frac{Ø^3 D_p^2}{(1 - Ø)^2}$$

where a is the proportionality and unity factor [mD/mm^2].

Directional Permeability

Typically, in very homogeneous reservoirs the permeability is considered to be identical in all directions. Conversely, in heterogeneous reservoirs, the permeabilities in all directions are considerably different. Such variations in the permeabilities in all directions have a significant impact on the efficiency of the natural recovery and on the waterflood process. Directional permeabilities can be obtained by using core plugs in the lab and by horizontal well test analysis using selective zonal well testing techniques. Normally, core plugs are cut perpendicularly from the main wellbore core. Also, the vertical permeability is cut perpendicular to the bedding plane,. The latest technological developments in well logging also provide the estimates of directional permeability. Directional permeability is often used to describe the amount of heterogeneity in the reservoir rock. The main effect of anisotropy is either the loss or gain in effective permeability of a reservoir rock. This can occur because the permeability increased in one direction and decreased in another direction. This effect, causing average permeability is less than the highest permeability in any direction. To illustrate these phenomena when a vertical fractured reservoir has higher permeability in the vertical direction and low matrix permeability in the horizontal direction. These differences in reservoir rock permeability known as anisotropy



Lorenz Coefficient

In 1950, Schmalz and Rahme (1950) presented a single factor that defines the degree of reservoir rock heterogeneity within a pay zone section. The term is named Lorenz coefficient and varies between zeros, for a totally homogeneous reservoir rock, to one for a totally heterogeneous reservoir rock.

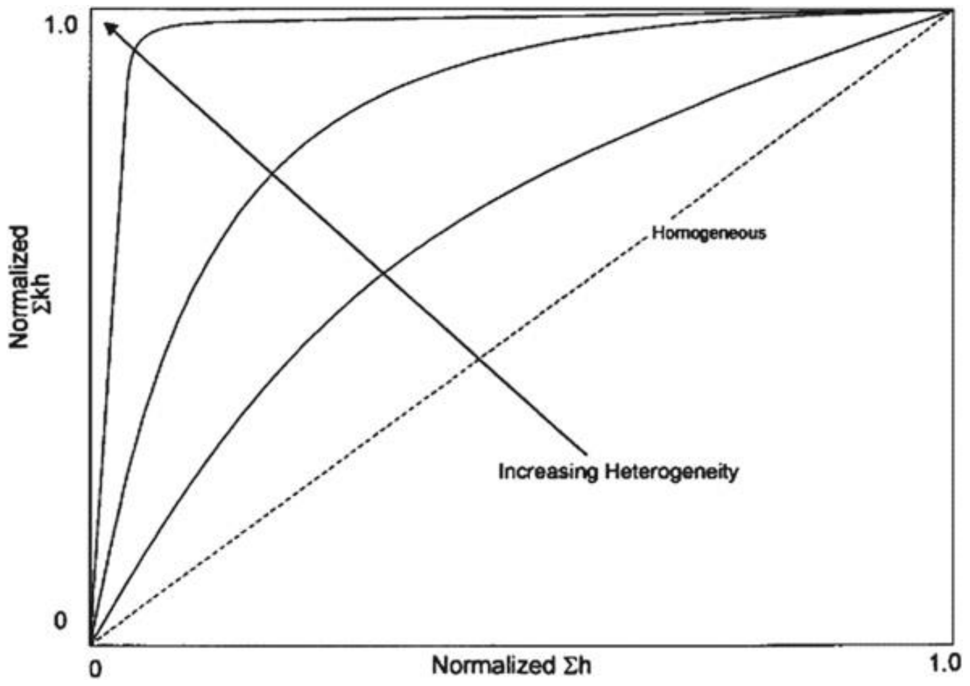
The main steps for calculating the Lorenz coefficient are as follows:

(1) Put all the permeability values in descending order.

(2) Determine both, the cumulative permeability capacity kh and cumulative volume capacityϕh.

(3) Normalize both cumulative capacities from 0 to 1. (0 TOTALLY HOMOGENOUS 1 TOTALLY HETEROGENOUS)

(4) Plot the normalized cumulative permeability capacity against the normalized cumulative volume capacity on a Cartesian scale.



Examples

Example 1: Brine water with viscosity 1.1 cP was flowing in the core sample at a constant rate of 0.35 cm cubic/s with 1.5 atm pressure differential. The core sample long is 3.5 cm and the cross section area is 4 cm square

Calculate the absolute permeability.

Example 2: Use the same data in Example 1 assuming that an oil viscosity used this time is 3 cP to determine the absolute permeability at same deferential pressure with 0.2 cm3/s flow rate?

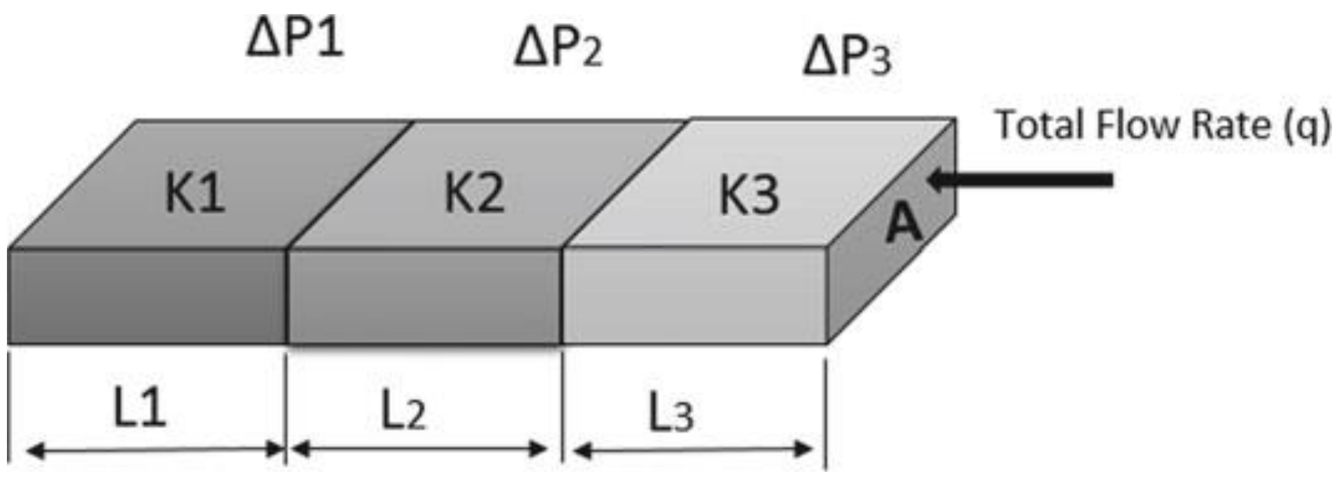
Examples

Example 3: Determine the average permeability of the reservoir rock has the following permeability core data analysis:

Bed	Interval depth (ft)	Permeability value (md)
1	2500–2504	150
2	2504–2508	120
3	2508–2015	180
4	2515–2520	130
5	2520–2525	110
6	2525–2531	200

Examples

Example 4: Calculate an average reservoir permeability for a series reservoir beds have average permeability of 10, 50 and 1000 md, which are 6, 18 and 40 ft respectively in length but of equal cross-section when placed in series as shown in the below Figure.



Examples

Example 5: There are six reservoir stratums were stacked in series. All stratums have equal thickness. The length and permeability for each stratum are given in the below table.
Estimate the average reservoir permeability of linear flow system

Bed	Length (ft)	Permeability (md)
1	100	90
2	200	70
3	150	60
4	300	45
5	150	30
6	200	15

Examples

Example 5: There are six reservoir segments were stacked in series. All stratums have equal thickness. The length and permeability for each stratum are given in the below table. By assuming wellbore radius is 0.24 ft, Estimate the average reservoir permeability of redial flow system

Bed	r_i (ft)	k_i (md)	$\ln(r_i/_{riB1})$
1	150	80	6.397
2	350	50	0.847
3	650	30	0.619
4	1150	25	0.571
5	1350	10	0.160

Examples

Example 6: Using Timur equation, calculate the absolute of an oil-bearing zone has the average porosity of 20% and water saturation 25%.

Example 7: Using Morris and Biggs equation, calculate the absolute of an oil-bearing zone has the average porosity of 20% and water saturation 25%.

Examples

Example 6: A gas flow test is performed at two pressures:

Test 1; applied P = 12 atm

Test 2; applied P = 3 atm.

The test used a rock has absolute permeability of 2.0 md, and the gas viscosity of 0.01 cP, can be considered as constant value for both tests. Klinkenberg's b-factor approximately equal to 1.0 for rock has a permeability of 2.0 mD.

Calculate the apparent gas permeability for the two tests?