BHARATHIDASAN UNIVERSITY

Tiruchirappalli - 620 024
Tamil Nadu, India

Programme : 6 year Integrated M.Tech in Geological Technology and Geoinformatics

Course title : Petroleum Geology
Course code : MTIGT 0701

UNIT – III

Reservoir Engineering

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Reservoir engineering is a branch of petroleum engineering that applies scientific principles to the problems arising during the development and production of oil and gas reservoirs so as to obtain a high economic recovery of hydrocarbons.

For the same **petrophysical** properties of the reservoir rocks are very important. The term "**Petrophysics**" denotes the study of the physical and chemical properties of rocks and their contained fluids.

Role of the **Petrophysicists**

The evaluation of subsurface formations requires the combined efforts of geologists, petrophysicists, drilling engineers and geophysicists. However, it is the geologist and petrophysicist that has the most influence.

The petrophysicist's job is to use all available information to analyze the physical and chemical properties of the rocks in the subsurface.

The petrophysicist will use extensively wireline log data and data from experiments done on cores extracted from the well, and will also use mud logging data.

The aim of the petrophysicist is to differentiate between oil, gas and water bearing formations, estimate the porosity of the formations and the approximate amount of hydrocarbons present in each formation.

For any given well, petrophysicist helps to :

1. Distinguish between reservoir and non-reservoir rock (Reservoir rock contains a reasonably high connected porosity)

2. For the reservoir intervals only, distinguish between hydrocarbons and water filling the pores, hence calculate water saturation in reservoir rocks. (Hydrocarbons are electrical insulators, while water conducts)

3. For the hydrocarbon fraction, distinguish between oil and gas, hence calculate gas and oil saturations in reservoir rocks. (Gas has a much lower density than oil)

POROSITY

The porosity of a rock is the fraction of the volume of pore spaces available in the rock to the total rock volume.

This includes all pores, cracks, voids, etc. The porosity is conventionally given the symbol f, and is expressed either as a fraction varying between 0 and 1, or a percentage varying between 0% and 100%. Sometimes porosity is expressed in 'porosity units', which are the same as percent (i.e., 100 porosity units (pu) = 100%).

Porosity is calculated using the relationship

$$f = \frac{V_{pore}}{V_{bulk}} = \frac{V_{bulk} - V_{matrix}}{V_{bulk}} = \frac{V_{bulk} - \left(W_{dry} / r_{matrix}\right)}{V_{bulk}},$$

where: V_{pore} = pore volume
V_{bulk} = bulk rock volume
V_{matrix} = volume of solid particles composing the rock matrix
W_{dry} = total dry weight of the rock
r_{matrix} = mean density of the matrix minerals

Estimation of Porosity does not give any information concerning pore sizes, their distribution, and their degree of connectivity.

Rocks of the same porosity can have widely different physical properties. An example of this might be a shale and a sandstone. Each could have a porosity of 0.2, but shale pores are often not connected resulting in its permeability being much lower than that of the sandstone.

A range of differently defined porosities are recognized and used within the hydrocarbon industry.

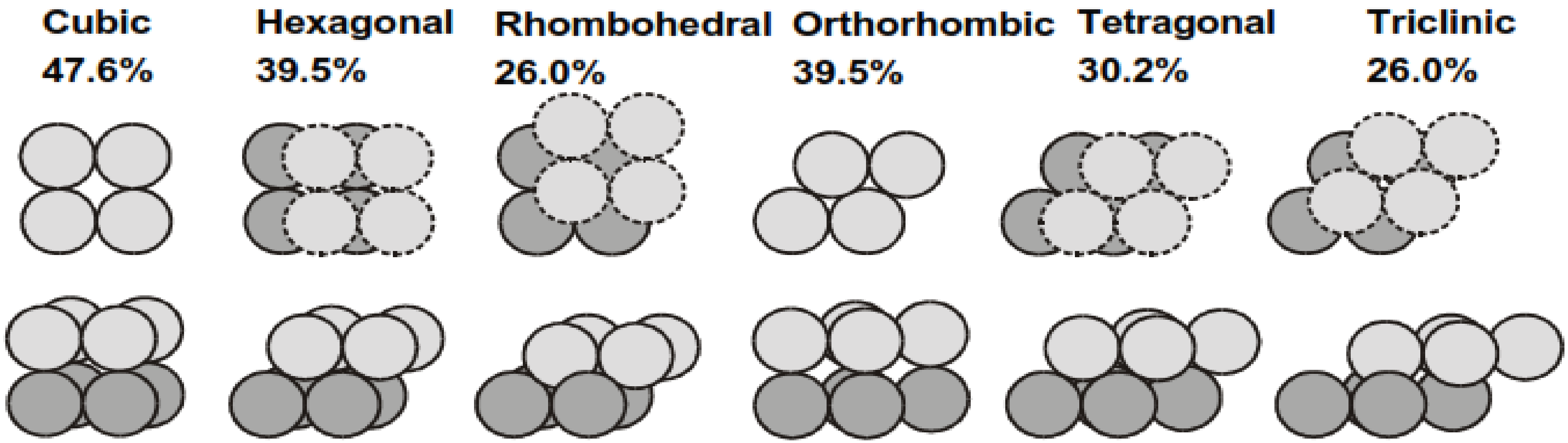
Total porosity - Defined above.
Connected porosity - The ratio of the connected pore volume to the total volume.
Effective porosity - The same as the connected porosity.
Primary porosity - The porosity of the rock resulting from its original deposition.
Secondary porosity - The porosity resulting from diagenesis.
Microporosity - The porosity resident in small pores (< 2 mm) commonly associated with detrital and authigenic clays.
Intergranular porosity - The porosity due to pore volume between the rock grains.

Controls on Porosity

The initial (pre-diagenesis) porosity is affected by the following parameters: 1. Grain packing, 2. Grain size, 3. Particle shape, and 4. the distribution of grain sizes.

Grain Packing

The theoretical porosities for various grain packing arrangements can be calculated. The theoretical maximum porosity for a cubic packed rock is 47.6% and is independent of grain size.

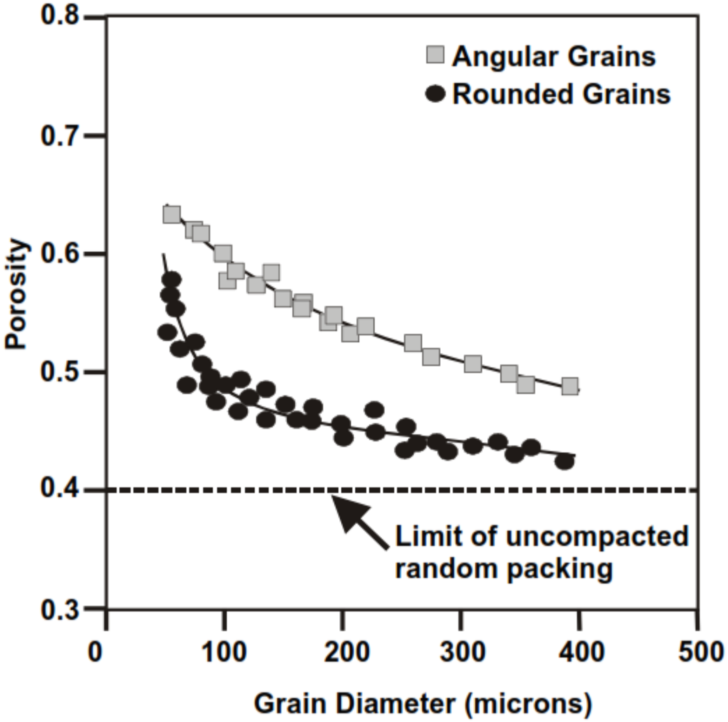


Grain Size

The ordered cubic packing of identical sphere leads to a porosity that is grain size independent.

This is also true for the other ordered packing lattices, but not true for the random arrangement of spheres. In real depositional environments, ordered packings are not formed and the grains are randomly distributed.

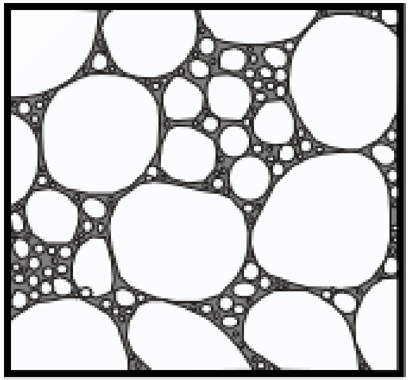
Studies have indicated that coarse grains will be stabilized at a lower porosity than the finer grains.



Grain Shape

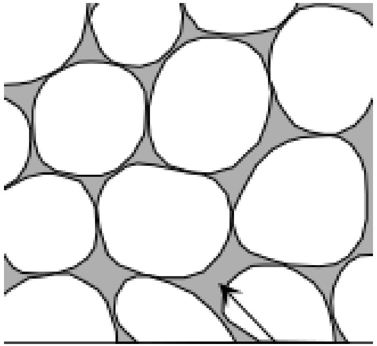
Several studies have been carried out on the angular and rounded grains, and in all cases the resulting porosities are larger than those for angular. The comparison of rounded and angular grains, again shows that the porosity of the angular grains is larger than those that are sub-spherical.

Grain Size Distribution



Poorly sorted sediments usually have lower porosity because the fine-grained fragments tend to fill in the open space.

Well-rounded coarse-grained sediments usually have higher porosity than fine-grained sediments, because the grains do not fit together well.



PERMEABILITY

The permeability is a measure of the ease with which the rock / formation will permit the passage of fluids.

About 150 years ago Darcy carried out simple experiments on packs of sand, and developed an empirical formula that remains the main permeability formula in use in the oil industry today.

Darcy's formula can be expressed as

$$Q = \frac{k\,A\,(P_i - P_o)}{m\ \ L}$$

Q = the flow rate (cm^3/s or m^3/s)
P_o = the outlet fluid pressure ($dynes/cm^2$ or Pa)
P_i = the inlet fluid pressure ($dynes/cm^2$ or Pa)
m = the dynamic viscosity of the fluid (poise or Pa.s)
L = the length of the tube (cm or m)
k = the permeability of the sample (darcy or m^2)
A = the area of the sample (cm^2 or m^2)

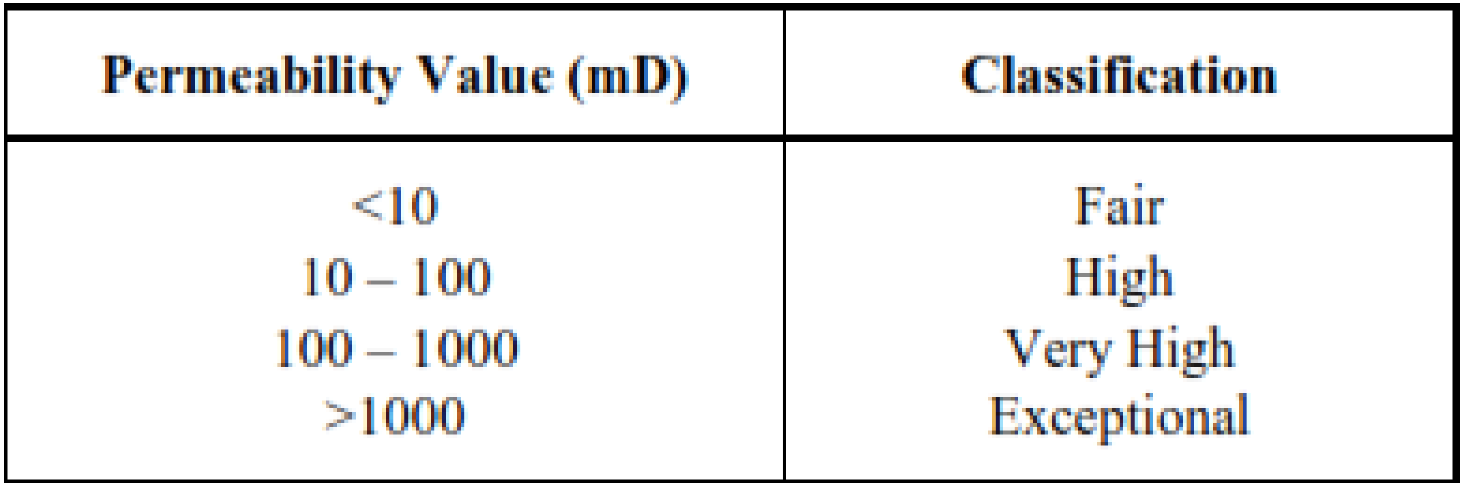
Permeability will depend on porosity; the higher the porosity the higher the permeability. However, permeability also depends upon the connectivity of the pore spaces, in order that a pathway for fluid flow is possible.

The connectivity of the pores depends upon many factors including the size and shape of grains, the grain size distribution etc.

However, we can make some generalizations if all other factors are held constant:

- *The higher the porosity, the higher the permeability.*
- *The smaller the grains, the smaller the pores and lower the permeability.*
- *The smaller the grain size, the larger the exposed surface area to the flowing fluid, which leads to larger friction between the fluid and the rock, and hence lower permeability.*

For reservoir rocks permeability can be classified as



Permeability Value (mD)	Classification
<10	Fair
10 – 100	High
100 – 1000	Very High
>1000	Exceptional

Reservoir Fluids

Reservoir fluids are a complex mixture of many hundreds of hydrocarbon components plus a number of nonhydrocarbons (referred to as inerts).

Hydrocarbons will be C_1 to C_n where $n > 200$. The main inerts are carbon dioxide (CO_2), nitrogen (N_2) and hydrogen sulphide (H_2S).

Hydrocarbons are generated in “source rock” by the breakdown of organic material at high temperature and pressure, then migrate upwards into “traps” where permeable rock above displaces the water originally present.

The fluid properties of any particular mixture will depend on reservoir temperature and pressure. The nature of the hydrocarbon mixture generated will depend on the original biological material present, the temperature of the source rock and the pressure, temperature and time taken.

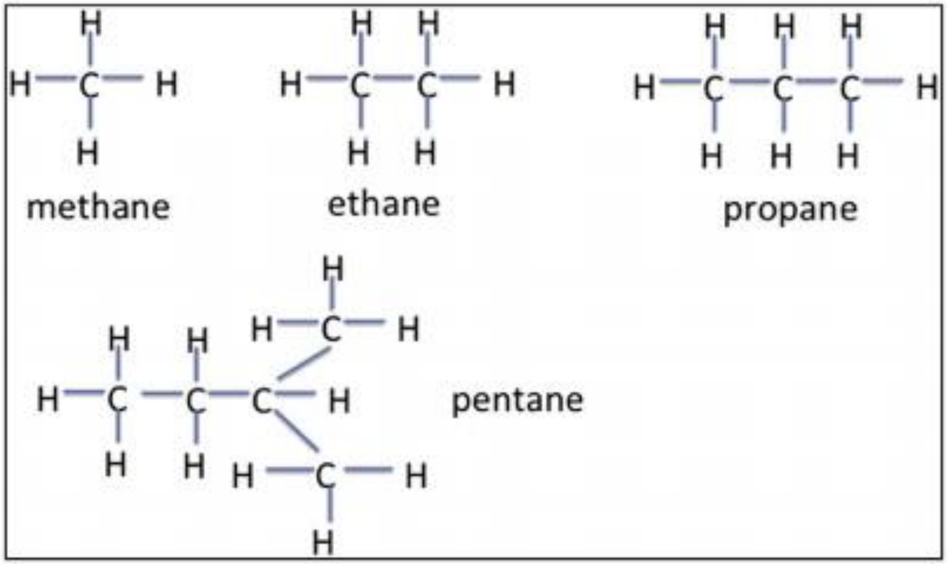
A number of phases of migration can occur, with different inputs mixing in the reservoir trap. In the reservoir we can eventually have single-phase (unsaturated) or two-phase (saturated) systems.

Hydrocarbons

Methane, ethane, and propane are always present in varying amounts (dominating in gases); normal and isobutane and pentane are also normally present. C_{6+} *(up to* C_{200} *or more) will dominate in oils.*

Inerts

Carbon dioxide and hydrogen sulphide are a problem for they give acid solutions in water which are corrosive to metal pipelines and wellbore pipes. We also have the cost of removal, and in some H_2S *cases even the disposal of unwanted sulfur is a problem.*



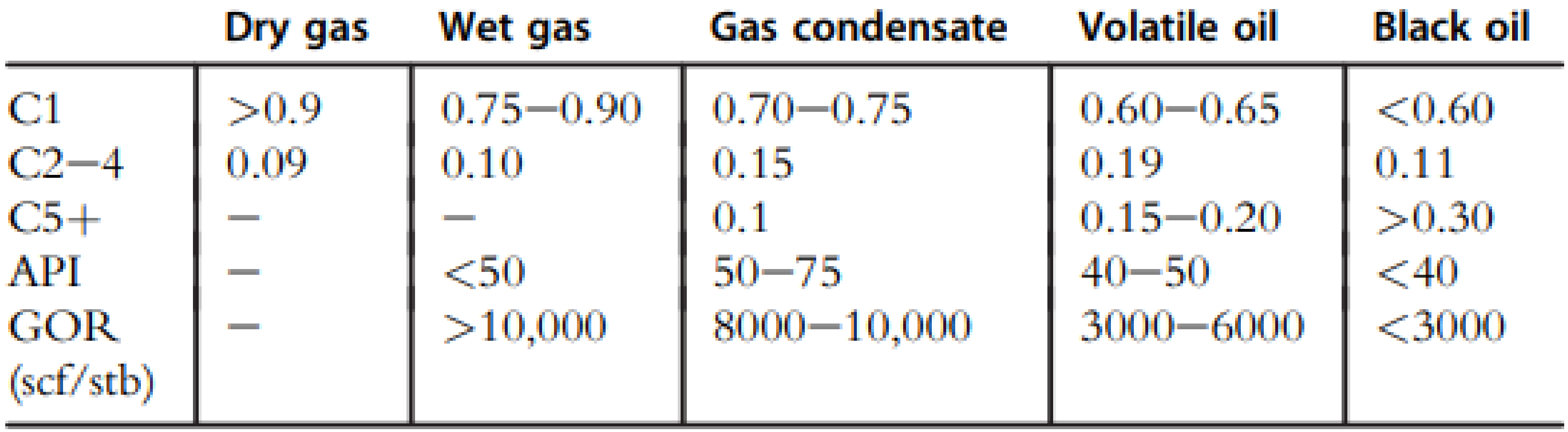
Some common reservoir hydrocarbons.

Types of Reservoir Fluid

There are five types of reservoir fluid.

- *Dry gas reservoirs.*
- *Wet gas reservoirs.*
- *Gas condensate.*
- *Volatile oil.*
- *Heavy oil.*

Which fluid is present will depend on the total hydrocarbon mixture composition and its pressure and temperature.



	Dry gas	**Wet gas**	**Gas condensate**	**Volatile oil**	**Black oil**
C1	>0.9	0.75–0.90	0.70–0.75	0.60–0.65	<0.60
C2–4	0.09	0.10	0.15	0.19	0.11
C5+	–	–	0.1	0.15–0.20	>0.30
API	–	<50	50–75	40–50	<40
GOR (scf/stb)	–	>10,000	8000–10,000	3000–6000	<3000

The methane (C_1) molar fraction will typically be above 90% for a dry gas and below 60% for heavy (black) oil. The C_{5+} content will be negligible in a dry gas and more than 30% in heavy oil. API (American Petroleum Institute) is a measure of density (API ¼ 141.5/Sg60d131.5 relates this to specific gravity relative to water at 60 F). Gas Oil ratio (GOR) is the gas content at 1 atm pressure and 60 F.

The range of temperatures and pressures to be considered by the reservoir engineer needs to cover those found in reservoirs through to atmospheric conditions with all possible temperature and pressures in between which may be encountered in the wellbore, surface pipelines, and separators

Reservoir fluids fall into three broad categories:

1. aqueous solutions with dissolved salts
2. liquid hydrocarbons and
3. gases (hydrocarbon and non-hydrocarbon)

In all cases their compositions depend upon their source, history, and present thermodynamic conditions. Their distribution within a given reservoir depends upon the thermodynamic conditions of the reservoir as well as the petrophysical properties of the rocks and the physical and chemical properties of the fluids themselves.

Thermodynamics deals with heat and temperature, and their relation to energy, work, radiation, and properties of matter.

Fluid Distribution

Reservoir fluids depend not only on the characteristics of the rock-fluid system but depend on several factors and the most important are:

Depth *The difference in the density of the fluids results in their separation over time due to gravity (differential buoyancy).*

Fluid Composition *The composition of the reservoir fluid has an extremely important control on its pressure-volume-temperature properties.*

Reservoir Temperature *Exerts a major control on the relative volumes of each fluid in a reservoir.*
Fluid Pressure *Exerts a major control on the relative volumes of each fluid in a reservoir.*
Fluid Migration *Different fluids migrate in different ways depending on their density, viscosity. The mode of migration helps define the distribution of the fluids in the reservoir.*

Trap-Type *Clearly, the effectiveness of the hydrocarbon trap also has a control on fluid distribution (e.g., cap rocks may be permeable to gas but not to oil).*

Rock structure *The microstructure of the rock can preferentially accept some fluids and not others through the operation of wettability contrasts and capillary pressure.*

For example, it is gravity that ensures, that when all three basic fluids types are present in an uncompartmentalised reservoir, the order of fluids with increasing depth is ***GAS: OIL: WATER.***

Aqueous Fluids

Accumulations of hydrocarbons are always associated with aqueous fluids (formation waters), which may occur as extensive aquifers underlying or interlaying with hydrocarbon bearing layers, but always occur within the hydrocarbon bearing layers as connate water.

These fluids are commonly saline, with a wide range of compositions and concentrations. Usually, the most common dissolved salt is NaCl, but many others occur in varying smaller quantities. The specific gravity of formation waters increases with salinity at a rate of about 0.075 per 100 parts per thousand of dissolved solids.

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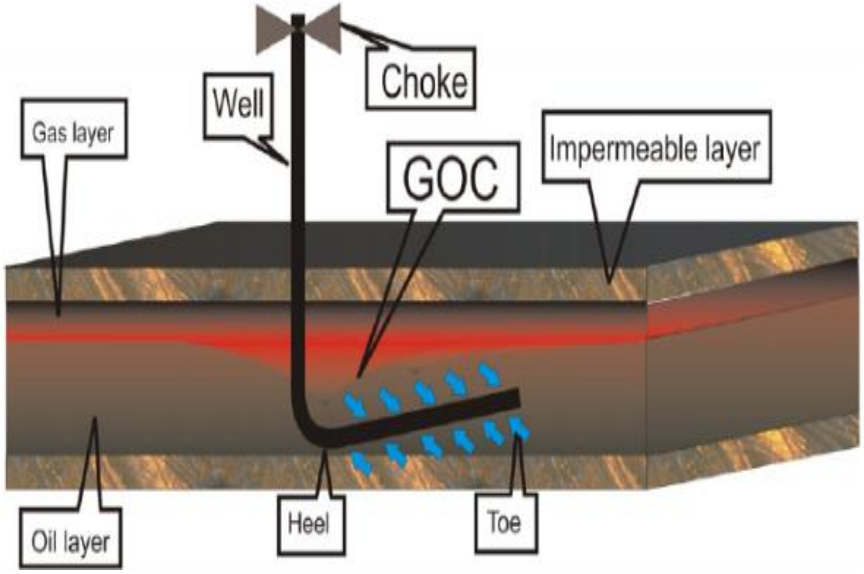
Composition of Formation Water

Component	**Concentration, g dm^{-3}**
Pure water	Solvent
$NaCl$	34.70
$CaCl_2.6H_2O$	4.90
$MgCl_2.6H_2O$	2.70
KCl	0.40
$NaHCO_3$	0.40
$SrCl_2.6H_2O$	0.12
$BaCl_2.6H_2O$	0.06
Final pH = 7	

Fluid flow through porous media has been an important research topic for decades especially in the areas of groundwater movement, petroleum engineering, geology, and geophysics.

A petroleum reservoir system is one example of a system where fluid flow control is critically important to maximize recovery of the available hydrocarbon resources. The reservoir is a subsurface pool of hydrocarbons (oil and gas) contained in porous or fractured rock formations. Oil and gas are trapped by overlying rock formations with close to zero permeability. Because the density of the gas is lower than the density of oil, the gas remains at the top of the reservoir. To produce the oil, a reservoir is completed with production wells.



The horizontal part of the well in the figure is perforated between the well heel and the well toe to allow inflow of the reservoir fluid. Due to a viscosity difference between the gas and the oil, the gas will push the oil downward through the well perforation; hence, it will create an inverse cone along the well. The inverse cone, characterized by the interface between the oil and gas, is defined as the gas oil contact (GOC), and the phenomenon is called gas coning.

Reservoir Pressure, also known as formation pressure or hydrostatic pressure is the pressure of the fluids present in a hydrocarbon reservoir. It can also be stated as the pressure which is exerted by column of water on sea level from the depth of a hydrocarbon reservoir inside the earth's surface.

Reserves estimation

The process of estimating oil and gas reserves for a producing field continues throughout the life of the field. There is always uncertainty in making such estimates. The level of uncertainty is affected by the following factors:

1. *Reservoir type,*
2. *Source of reservoir energy,*
3. *Quantity and quality of the geological, engineering, and geophysical data,*
4. *Assumptions adopted when making the estimate,*
5. *Available technology, and*
6. *Experience and knowledge of the evaluator.*

The magnitude of uncertainty, however, decreases with time until the economic limit is reached and the ultimate recovery is realized

The oil and gas reserves estimation methods can be grouped into the following categories:

1. ***Analogy,***
2. ***Volumetric,***
3. ***Decline analysis,***
4. ***Material balance calculations for oil reservoirs,***
5. ***Material balance calculations for gas reservoirs,***
6. ***Reservoir simulation***

In the early stages of development, reserves estimates were restricted to the analogy and volumetric calculations.

The analogy method is applied by comparing factors for the analogous and current fields or wells.

A close-to-abandonment analogous field is taken as an approximate to the current field. This method is most useful when running the economics on the current field; which is supposed to be an exploratory field.

ANALOGY

The analogy method is applied by comparing the following factors for the analogous and current fields or wells:

- Recovery Factor (RF),
- Barrels per Acre-Foot (BAF), and
- Estimated Ultimate Recovery (EUR)

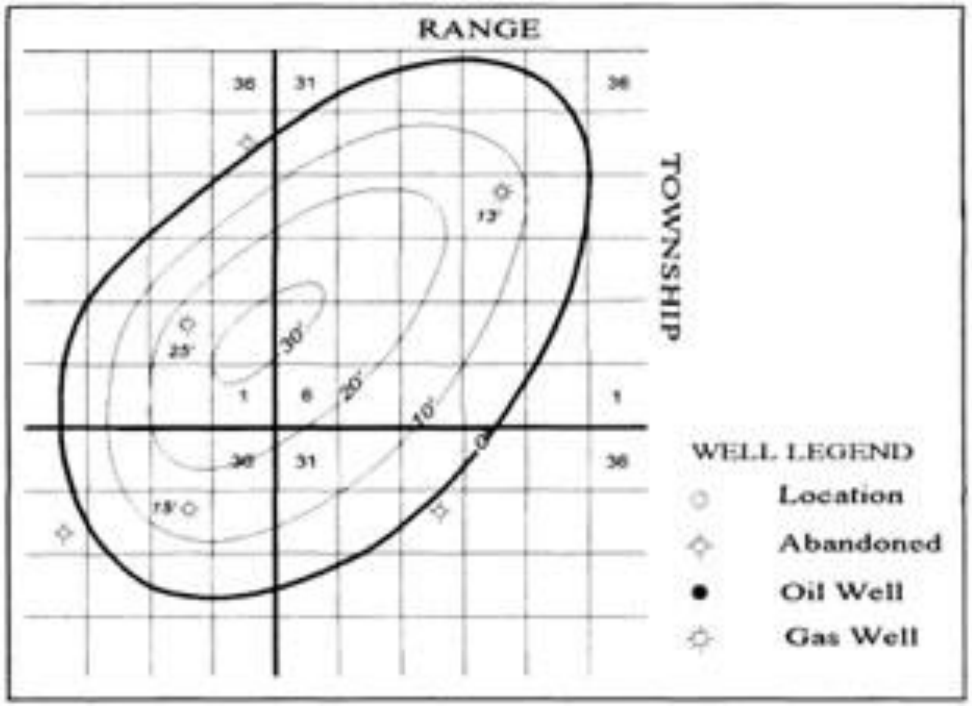
The RF of a close-to-abandonment analogous field is taken as an approximate value for another field.

Volumetric method

Volumetric method entails determining the physical size of the reservoir, the pore volume within the rock matrix, and the fluid content within the void space.

This provides an estimate of the hydrocarbons-in-place, from which ultimate recovery can be estimated by using an appropriate recovery factor.

Each of the factors used in the calculation have inherent uncertainties that, when combined, cause significant uncertainties in the reserves estimate. The below figure is a typical geological net pay isopach map that is often used in the volumetric method.



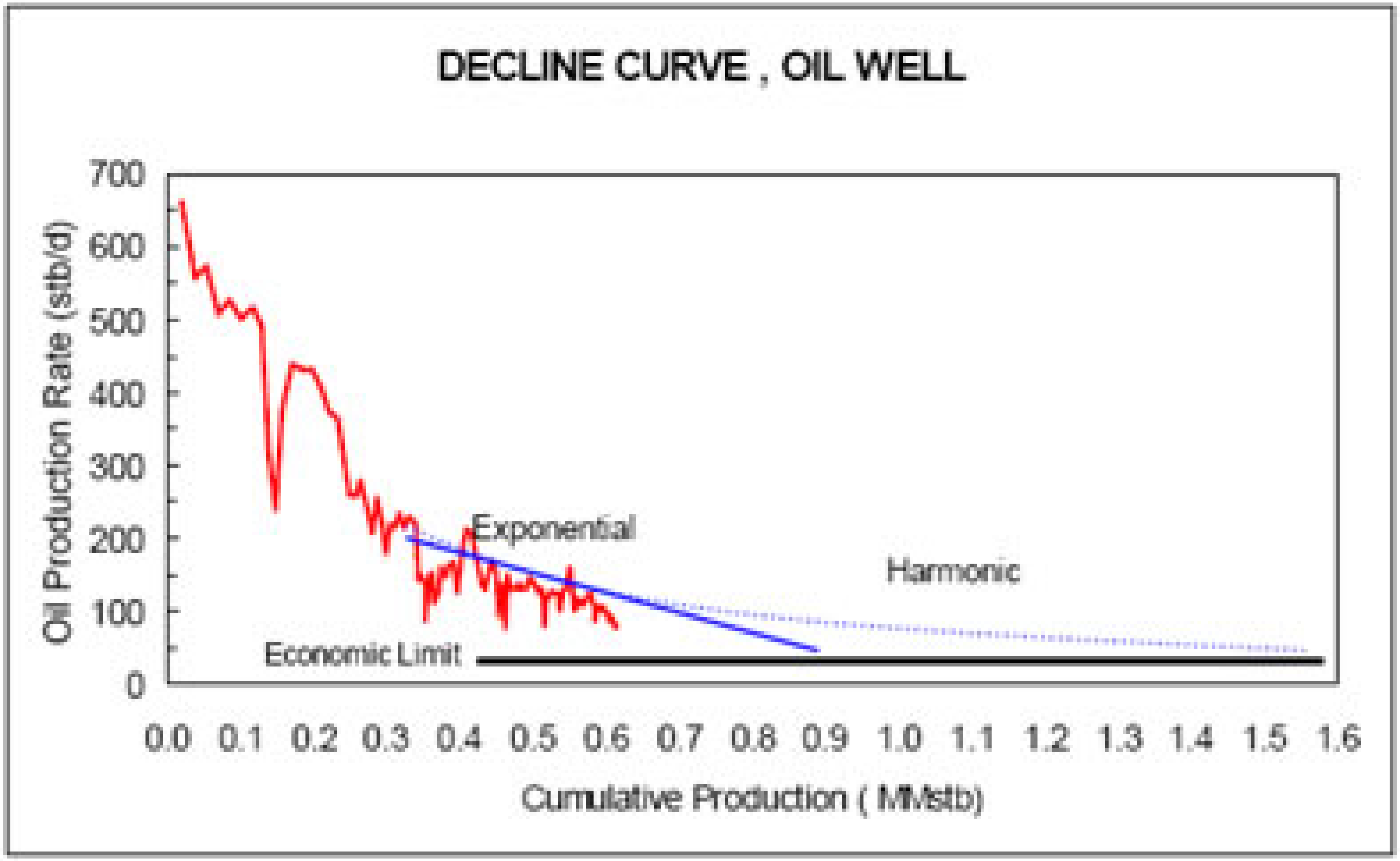
DECLINE CURVE

A decline curve of a well is simply a plot of the well's production rate on the y-axis versus time on the x-axis. The plot is usually done on a semilog paper; i.e. the y-axis is logarithmic and the x-axis is linear.

When the data plots as a straight line, it is modeled with a constant percentage decline "exponential decline". When the data plots concave upward, it is modeled with a "hyperbolic decline". A special case of the hyperbolic decline is known as "harmonic decline".

The most common decline curve relationship is the constant percentage decline (exponential). With more and more low productivity wells coming on stream, there is currently a swing toward decline rates proportional to production rates (hyperbolic and harmonic).

Although some wells exhibit these trends, hyperbolic or harmonic decline extrapolations should only be used for these specific cases. Over-exuberance in the use of hyperbolic or harmonic relationships can result in excessive reserves estimates. The below figure is an example of a production graph with exponential and harmonic extrapolations.



DECLINE CURVE , OIL WELL

Reservoir simulation

Is the process of inferring the behavior of a real reservoir from the performance of a model of that reservoir. The model may be physical, such as a scaled laboratory model, or mathematical.

A mathematical model of a real reservoir is a set of partial differential equations, together with an appropriate set of boundary conditions, which are believed to adequately describe the significant physical processes taking place in the real reservoir.

The processes taking place in a real reservoir are fluid flow and mass transfer. Up to three immiscible phases (gas, oil, and water) may flow simultaneously where gravity, capillary, and viscous forces play an important role in the flow process. Mass transfer may take place between the phases (chiefly between gas and oil phases).

T

The model equations must account for all forces, and should also take into account an arbitrary reservoir description with respect to heterogeneity and geometry. The equations are obtained by combining the mass conservation equation with the equation of motion (Darcy's law).

To use the mathematical model for predicting the behavior of a real reservoir, it is necessary to solve the model equations subject to the appropriate boundary conditions.

The methods of solution are basically divided into two main methods, analytical and numerical. Analytical methods are applicable only to the simplest cases involving homogeneous reservoirs and very regular boundaries. Numerical methods, on the other hand, are extremely general in their applicability and have proved to be highly successful for obtaining solutions to very complex reservoir situations.

A numerical model of a reservoir, then, is a computer program that uses numerical methods to obtain an approximate solution to the mathematical model."