Let us speak about reservoir Engineering

Fluid distribution in a virgin field – Consolidation, gravity and capillarity.

The reservoir rock is built through conventional consolidation and diagenesis processes. Coarse sediments (sands or lime grains) saturated by sea water are deposited on the sea bed then progressively buried and loaded by overlying sediments (**Figure 1**).

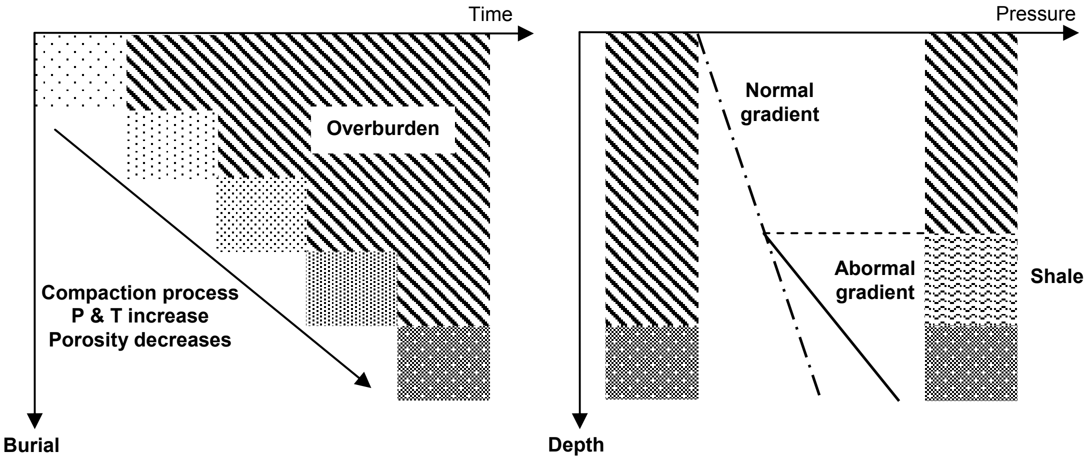


Figure 1 – Compaction process
Normal and abnormal pore pressure gradient

Following this loading process, grains compact, porosity decreases and, as water is expelled, pore pressure increases either with a normal pressure gradient (pressure equal to the weight of the hydrostatic column) or sometimes with an abnormal gradient (pressure greater than hydrostatic pressure) when water cannot be expelled because of an impermeable overburden that totally seals the reservoir. As the burial increases, the temperature of the rock also increases according to the local geothermal gradient. In this hot and pressurised environment the sediments are themselves subjected to very slow thermodynamic transformations (diagenesis) which progressively build the future rock fabric. At this stage, the reservoir is therefore solely saturated by hot water under pressure.

The phase during which the oil will progressively move from the source rock towards the reservoir where it will be trapped is called "migration". As water and oil have quite different physical properties (density, viscosity, surface tension) and given the small size of the pores, migration will be a long and complex process mainly governed by capillary (oil migrates into most reservoirs as the non-wetting phase) and gravity forces. In particular, gravity will segregate the different fluids with the heavier (water) at the bottom and the lighter (gas) at the top.

A general picture of the final equilibrium of a virgin reservoir (anticline configuration) is shown in **Figure 2**. Due to its lower density, oil migrates to the upper part of the anticline whereas water, which is heavier, remains in the lower part. However, due to capillary forces (Jurin's law), water is not totally expelled from the oil zone. This remaining water phase can be quantified via the water saturation (ratio between local water volume and total pore volume) which evolves from 100% in the aquifer to a constant minimum value S_{WI} called irreducible water saturation within the oil zone. Therefore, above the OWC (Oil Water Contact) there is a transition zone in which the water saturation will decrease from 100% to S_{WI}.

The rock also plays a major role in the fluid distribution. The preference of a solid to contact a liquid or a gas (known as the "wetting phase") rather than another is called "wettability". Thus, depending on their surface tension, different fluids will spread out differently over a solid surface.

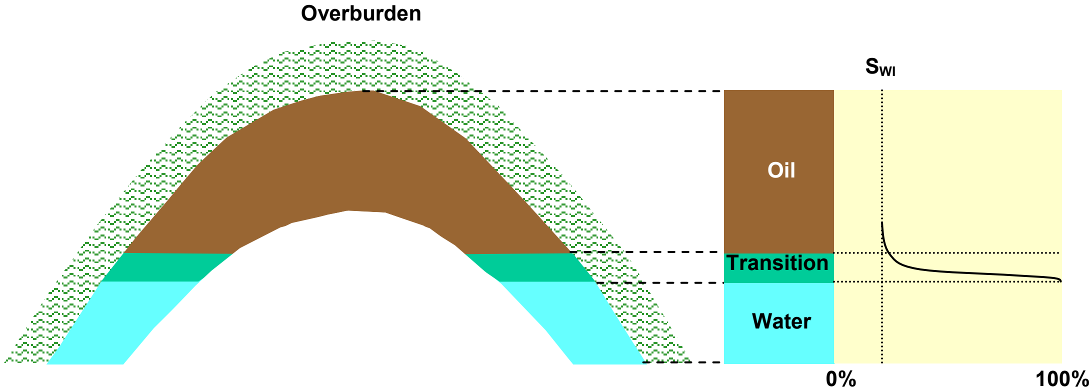


Figure 2 – Initial state of a virgin reservoir

Most rocks are generally water wet, which means that water will tend to coat the grains of the rock whereas the oil drops remain immersed in the central part of the pore (**Figure 3**).

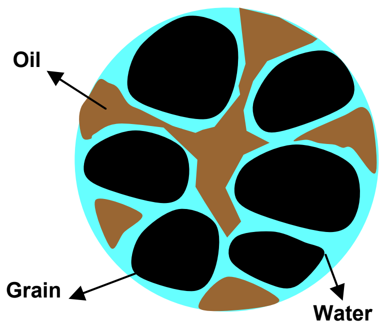


Figure 3 – Oil / water distribution in a porous medium

Furthermore, oil always contains dissolved gas and if the initial reservoir pressure is equal to the saturation pressure of gas in oil (called the bubble pressure p_b), gas appears as a free phase which forms a "gas cap" at the top of the reservoir (**Figure 4**). In a similar manner to the OWC, the limit between the oil and the gas is called the GOC (Gas Oil Contact). The gas oil transition zone again depends on the rock characteristics but is much thinner than the water oil transition zone. However, if the initial reservoir pressure is higher than the bubble pressure, there is no gas cap and the hydrocarbon remains single phase.

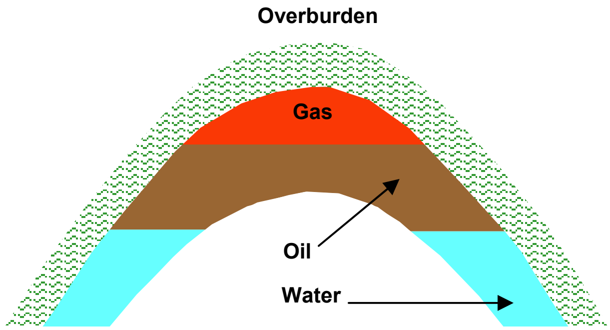


Figure 4 – Presence of a gas cap ($p_b = p_i$)

The extraction of hydrocarbons from the reservoir will profoundly disturb the initial state (the pressure will continuously decrease as hydrocarbons are extracted) and also the initial distribution of the fluids. Let us first analyse the case of a single phase flow for which fluid interactions can be ignored

Depletion of a reservoir filled by a single fluid

The main source of energy allowing hydrocarbons to flow out of the reservoir is their pressure. When a pressure gradient is created in the reservoir (e.g. by introducing a new well), pressure acts as a driving force and pushes the fluid out of the reservoir to the well. The pressure and flow rate decrease progressively while hydrocarbons are produced. This phenomenon is called "**natural depletion**". Natural depletion is similar to the decompression of an undeformable steel bottle filled with a pressurised gas. When opening the bottle, the gas is subjected to a pressure gradient and flows out. The pressure and flow gradually decrease as the bottle empties. When the inside and outside pressures equalise, the flow stops. During the whole process, the flow depends on the bottle orifice size and also on the properties of the fluid, i.e. viscosity (resistance to flow) and compressibility (ability to accumulate or release volumes of fluid when subjected to pressure variations). This can easily be transposed to the reservoir depletion scheme: the initial pressure in the bottle is the initial reservoir pressure, the bottle orifice is the rock permeability and the outside pressure is the downhole flowing well pressure.

Darcy's law and the diffusivity single phase flow equation

The velocity v_x of a fluid of viscosity μ flowing through a sample of porous medium section A, length dx and permeability k can be described using Darcy's law and written as follows (**Figure 5**):

$$v_x = -\frac{k}{\mu}\frac{\partial p}{\partial x} \qquad (1)$$

dp is the pressure gradient along the sample. The ratio k/μ is called the "fluid mobility".

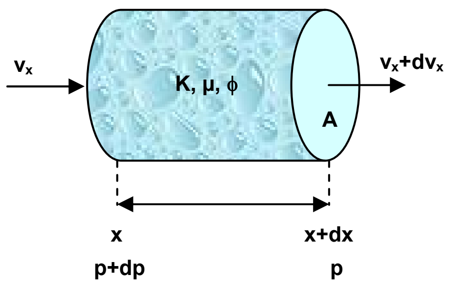


Figure 5 – Flow through a porous medium element

For the same element of porous medium (assumed incompressible), if we consider an inflow velocity v_x and an outflow velocity $v_x + dv_x$, the mass balance during a time increment dt is written[1]

$$(v_x + dv_x)A\,dt - v_x A\,dt = -C_f\,(A dx \phi)\,dp \qquad (2)$$

ϕ and C_f are respectively the rock porosity[2] and the fluid compressibility. Eliminating v_x between equations (1) and (2) leads to the diffusivity equation

[1] The minus sign of the right-hand side of equation (2) is explained by the fact that the fluid volume contained within the porous element decreases.

[2] Porosity is equal to the ratio between pore and total volumes.

$$\frac{k}{\phi\,\mu\,C_f}\,\frac{\partial^2 p}{\partial x^2}=\frac{\partial p}{\partial t} \qquad (3)$$

which can be generalised to 3D cases and compressible rocks

$$\frac{k}{\phi\mu\left(C_r+C_f\right)}\nabla^2 p=\frac{\partial p}{\partial t} \qquad (4)$$

where C_r is the rock compressibility. The sum of the fluid and the rock compressibilities is called the total compressibility and written C_t. For complex geometries, digital simulators must be used to solve equation (4). However, for simple boundary conditions it can be integrated analytically.

Depletion of a portion of reservoir around a single well

To qualitatively analyse the effect of each physical variable on depletion, let us consider an ideal cylindrical reservoir (**Figure 6**) of external radius R_d (called the "drainage radius") and height h crossed by a central borehole of radius R. Initially the reservoir is saturated by a single Newtonian fluid at pressure p_r. A zero flow rate is imposed on the external boundary (natural barriers or effect of neighbouring wells) whereas, at the borehole, a constant flow rate history is imposed i.e. a flow rate Q_i during a time increment t_{i-1}, t_i.

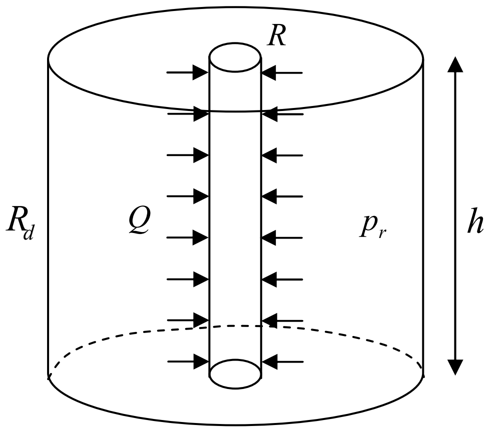


Figure 6 – Ideal axisymmetric well reservoir model

If we wait a sufficient time to obtain a pseudo permanent flow regime (pressure evolving linearly with time during a given time increment), the well pressure change can be calculated using the following equation:

$$p_w(t)=p_r-\sum_{i=1}^{n}C_1\left(Q_i-Q_{i-1}\right)\left[C_2\left(t-t_{i-1}\right)+C_3\right] \qquad (5)$$

where

$$C_1=\frac{\mu}{\pi\,k\,h} \quad C_2=\frac{k}{\phi\,\mu\,C_t R_d^2} \quad C_3=\frac{1}{2}\ln\frac{R_d}{R}-\frac{3}{8} \qquad (6)$$

Solving equation (5) by successive approximations allows the flow history corresponding to a constant well pressure to be calculated for a given set of parameters. These parameters can be divided into three categories (flowing pressure, volumetric parameters and flowing properties) which are studied below. All the cases have been calculated using a same initial reservoir pressure equal to 400 bars.

Flowing pressure
The pressure drawdown (also called "Delta p"), which is the difference between the current reservoir and well pressures, is the main driving force boosting the fluid from the reservoir to the well. If the well pressure is assumed to be constant as natural depletion occurs, the average reservoir pressure decreases during the process; the same will apply to the flowing pressure and production flow rate (**Figure 7**). In contrast to this, lowering the well pressure will boost both the production rate and the ultimate recovery (which only depends on the abandonment pressure). Water injection and artificial lift are major tools acting either on mean reservoir pressure or on well pressure to give the fluid additional energy when natural lift is no longer sufficient to produce the well economically.

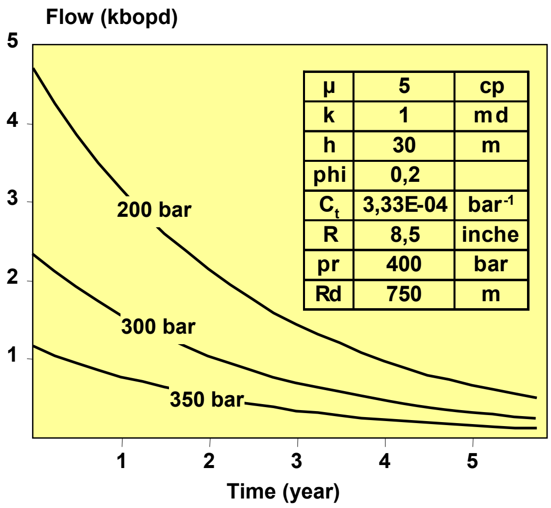


Figure 7 – Impact of well pressure on production.

Volumetric (static) parameters (**Figure 8)**
Several parameters (drainage radius, reservoir height and porosity) characterise the total amount of oil inside the drainage radius.

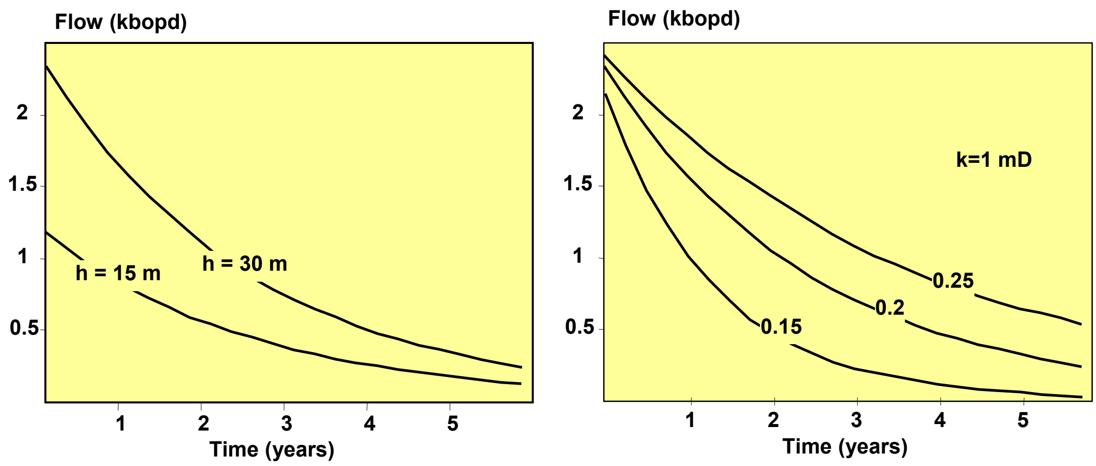


Figure 8 – Impact of volumetric natural parameters (on the left: reservoir thickness; on the right: porosity) on depletion history around a single well.

However we have to clearly distinguish the reservoir thickness and the rock porosity which are natural volumetric properties (characterising local Original Oil In Place _ OOPI) from the drainage radius.

Higher porosities and thicker reservoirs will correspond to an increasing OOIP (all other parameters remaining constant) and will induce higher production rates and ultimate recoveries. In contrast to this, the drainage radius is a key parameter linked to the development scheme since resulting from the number of wells and the spacing between them. It cannot therefore be properly analysed using a single well model and will be discussed in the next paragraph.

Fluid and rock flowing (dynamic) properties
For a constant well pressure and volumetric properties (including drainage radius - **Figure 9**), the higher the mobility the larger the initial flow rate but the quicker the decline rate (if we use our gas bottle analogy again, high permeability corresponds to a full opening of the valve so the bottle empties faster). However, mobility does not affect the ultimate recovery. But compressibility, which represents a supply of elastic energy for the rock and fluid system, affects both the flow and the recovery: the smaller the compressibility, the higher the elastic energy and therefore the higher the recovery.

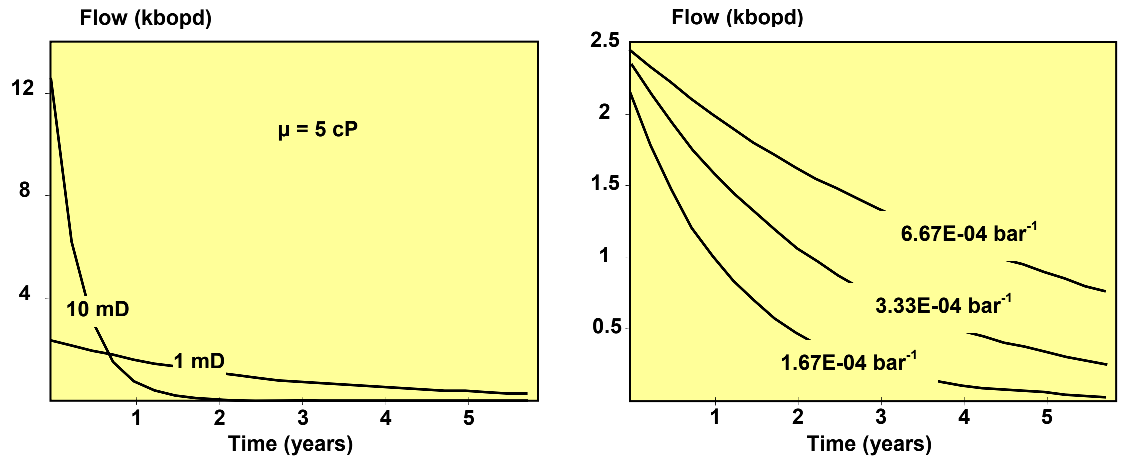


Figure 9 - Impact of mobility and compressibility on depletion history around a single well

Depletion of a reservoir – Optimisation of the spacing
In contrast to reservoir thickness and porosity, the drainage radius which is directly linked to the spacing between wells (the spacing is roughly equal to twice the drainage radius) appears as a key design parameter of the development scheme. It must be optimised for a field to be produced properly at an economical level over a sufficiently long period and strongly depends on natural (volumetric and dynamic) properties.

Using the same analytical formula (5), the case presented in **Figure 10** has been obtained by simply adding individual wells. It corresponds to a reservoir of 9km x 9km developed from a pattern of 9 production wells with a spacing of 3 km (drainage radius to 1.5 km). Flowing pressure is maintained constant at 100 bars throughout the whole process. The following drilling sequence is considered: first oil is produced from 4 initial wells, then 5 additional development wells are drilled and regularly put on stream every 3 months. Due to the supply from these additional wells, production increases over the first one and a half year, reaches a peak of 92 kbopd then decreases quite sharply. After six years and for the considered flowing conditions (remember that flowing pressure is 100 bars), production is nearly zero and around 81 MMbbls have been recovered.

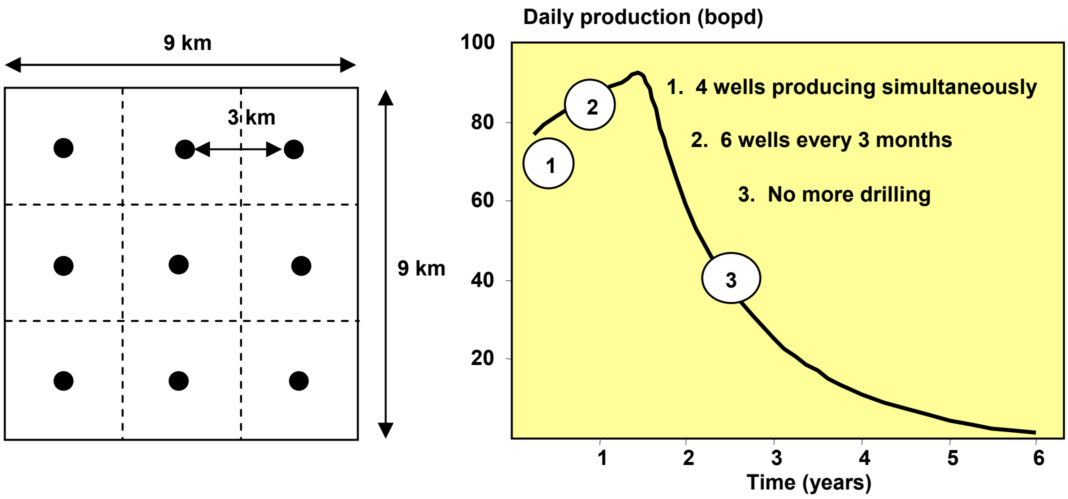


Figure 10 – Example of a development scheme with 9 production wells producing with natural depletion

Let us compare the case in **Figure 10** with a tighter well pattern using a well spacing reduced by a factor 2 (1.5 km that is 750 m of drainage radius), all the other parameters (including the flowing pressure) are kept constant. In this case the reservoir must be produced by 36 wells (instead of 9). The drilling sequence is qualitatively similar to that of the first case: first oil produced from 18 wells then 18 additional development wells drilled and regularly put on stream every 3 months. The drilling programme is stopped after nearly five years. As shown in **Figure 11**, although the initial production is higher, the final recovery after 6 years is the same. The tighter well pattern simply accelerates production.

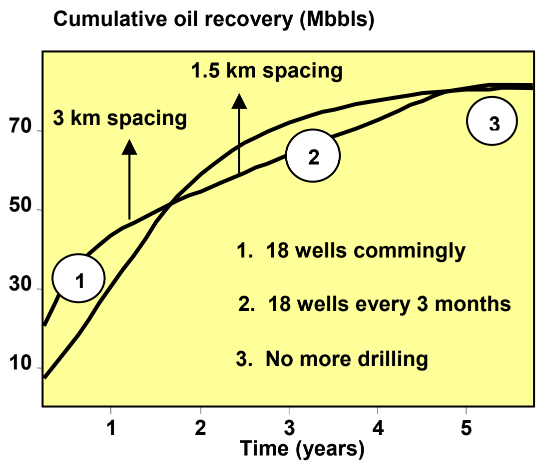


Figure 11 – Comparison of two development schemes with 750 m and 1500 m well spacings respectively

This simple analysis (it must be considered more qualitatively than quantitatively) highlights three initial conditions for limiting the decline phase of a field and for providing the fluid with sufficient mechanical energy over a sufficiently long period. They can be summarised as follows:

- Limit the decline rate of the (average) reservoir pressure. **Injection** (water or gas) will be the main tool to reach this first condition,
- Decrease the well pressure progressively when depletion occurs. **Artificial lift** will be the main tool to reach this second condition

- Adapt the well pattern to the change in reservoir conditions. Drilling **in-fill (production and/or injection) wells** will be the main tool to reach this third condition

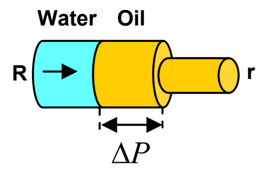
The above analysis has been perfomed using a single fluid flow analysis. Let us now study how the presence of two (oil + water) or three mobile fluids (oil + water + gas) can seriously complicate the flow and recovery processes.

Depletion of a biphasic reservoir (oil + water)

S_{WI} and S_{OR}

As mentioned earlier, during migration, oil from the source rock only displaces part of the water initially in place in the reservoir. For capillarity reasons a certain amount of water remains "stuck" to the rock, resulting in an initial water saturation equal to S_{WI} .

The (slow) displacement of the oil by the water in a porous medium (called "imbibition" if in a water wet system) is governed by the competition between viscous, gravity and capillary forces. When a drop of oil displaced by the water encounters a sharp restriction in the porous medium, the pressure required to overcome the capillary barrier (called the capillary pressure) can be calculated using a simple Laplace model (**Figure 12**).



$$\Delta P = 2\sigma\left(\frac{1}{r} - \frac{1}{R}\right)\cos\theta$$

Figure 12 – Capillary forces in a capillary doublet

For example, using[3] $\sigma \cos \theta$ = 30 dyn/cm, R = 5µ and r = 0,5µ we obtain a capillary barrier of 1 bar which corresponds to a very high threshold when compared with pressure gradients prevailing during production. Consequently, after complete water imbibition, a certain amount of oil remains trapped in the porous medium leading to a residual oil saturation, written S_{OR}. S_{OR} depends on the type of rock (typically between 15% and 40%).

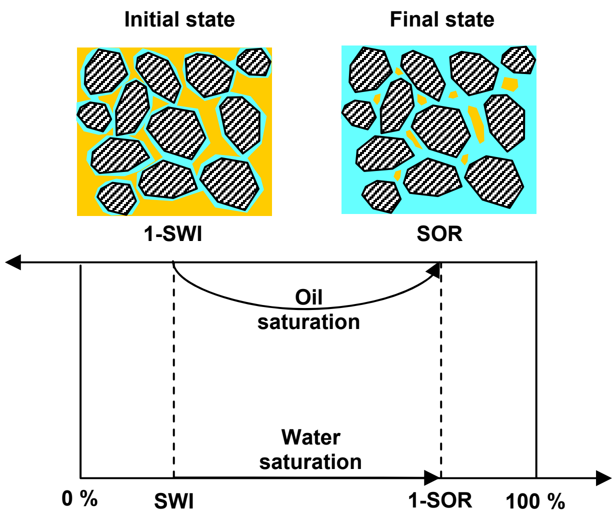


Figure 13 – Change in water and oil saturations during the depletion/imbibition process

3 σ is the superficial tension and θ the contact angle.

The change in the saturations during the depletion process is summarised in **Figure 13**: the initial state with respective water and oil saturations equal to S_{WI} and $1 - S_{WI}$ and the final state with respective water and oil saturations equal to $1 - S_{OR}$ and S_{OR}. The final state corresponds to that of a reservoir perfectly swept by water injection.

Relative permeability

Saturations are not purely static (i.e. volumetric) concepts. They also have a determinant effect on flow and consequently on production as shown in

Figure 14. Apart from the capillary pressure (fluid/fluid interaction), multiphase flow in a porous medium is also dependent on rock/fluid wettability. In the case of a single fluid, the flow is governed by the intrinsic or absolute permeability of the rock (i.e. the physical restriction between the two grains in

Figure 14) whereas for a biphasic oil/water flow, water stuck to the rock (the rock is supposed to be water wet) decreases the diameter of the restricted area. The flow of oil through the porous medium is no longer governed by the intrinsic (or absolute) permeability of the porous medium but by an "apparent permeability" highly dependent on the water saturation: the higher the water saturation the lower the permeability to oil but the higher the permeability to water.

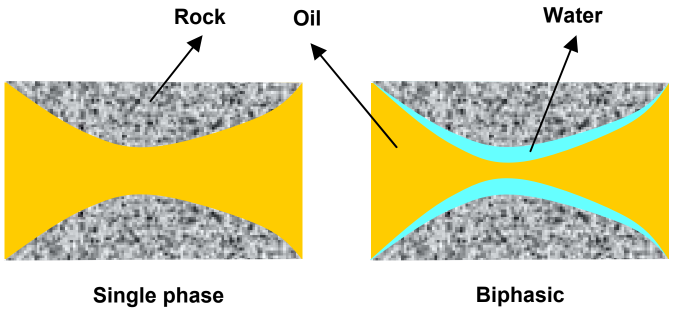


Figure 14 – Effect of saturation on permeability

This can be demonstrated quantitatively by performing a simple experiment in the laboratory consisting of slowly injecting water into a sample in which the initial state has been carefully restored (sample saturated with oil and water at S_{WI}). The results are summarised as follows:

- Water only circulates through the sample for a water saturation greater than or equal to S_{WI} which means that at S_{WI} the permeability to water is nil,
- Above S_{WI}, the permeability to water (written k_w) increases whereas the permeability to oil (written k_o) decreases. However, the sum of the water and oil permeabilities is always lower than the intrinsic single phase permeability ($k > k_o + k_w$). This means that the two fluids are mutually obstructed,
- For an oil saturation equal to S_{OR} (i.e. saturation to water equal to $1 - S_{OR}$) the oil stops circulating which means that the permeability to oil becomes nil

The biphasic flow range is therefore between S_{WI} and S_{OR}. To easily simulate a biphasic flow we introduce the concept of relative permeability to oil and water such that:

$$k_{rw} = \frac{k_w}{k} \qquad k_{ro} = \frac{k_o}{k} \qquad k_{ro} + k_{rw} < 1 \qquad (7)$$

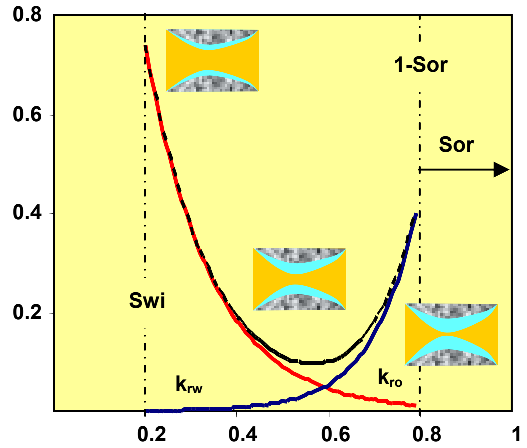


Figure 15 – Concept of relative permeability – Typical curves.

Relative permeability curves have an exponential shape as shown in **Figure 15**. These curves can be obtained from laboratory measurements. The concept of relative permeability gives a global description of multiphase flow but ignores complex microcapillary phenomena (saturation must be understood as an average value at centimetric or even metric scale). It allows the single phase theory to be extended to multiphase flow and Darcy's law to be generalised for each fluid, i.e.:

$$v_w = -\,k\frac{k_{rw}(S_w)}{\mu_w}\frac{\partial p}{\partial x} \qquad v_o = -\,k\frac{k_{ro}(S_O)}{\mu_o}\frac{\partial p}{\partial x} \qquad (8)$$

Water fraction and water cut (BSW)

The change in the (increasing) water fraction f_w produced during depletion can be easily calculated using relation (9):

$$f_w = \frac{q_w}{q_w + q_0} = \frac{\dfrac{k_{rw}}{\mu_w}}{\dfrac{k_{rw}}{\mu_w} + \dfrac{k_{ro}}{\mu_O}} = \frac{1}{1 + \dfrac{k_{rO}}{k_{rw}}\dfrac{\mu_w}{\mu_O}} \qquad (9)$$

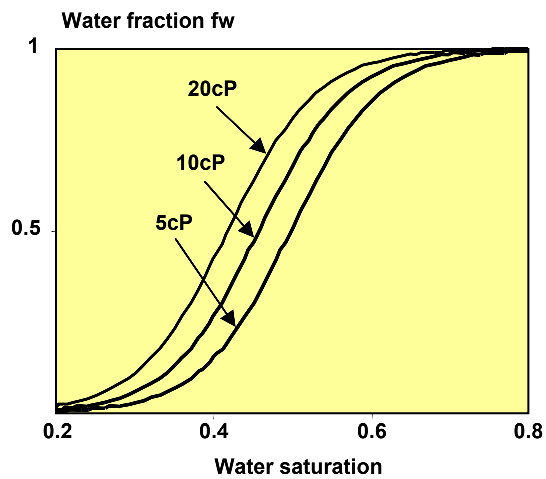


Figure 16 – Typical change in water fraction for various values of oil viscosity

Water fraction curves exhibit typical S-shaped changes like those in **Figure 16**. The higher the oil viscosity, the steeper the water fraction curve. As oil and water do not have the same volumetric properties, it is better to express f_w in standard rather than in downhole conditions. Introducing formation volume factors[4] B_w and B_o such that:

$$Q_w = \frac{q_w}{B_w} \qquad Q_0 = \frac{q_O}{B_O} \tag{10}$$

we obtain the water fraction in standard (i.e. surface) conditions such that:

$$BSW = \frac{1}{\frac{1-f_w}{f_w}\frac{B_w}{B_0}+1} \tag{11}$$

Depletion of a triphasic reservoir

Whatever the physical conditions, oil and water are never miscible. However, oil and gas can be miscible fluids and, depending on pressure and temperature, we can have gas dissolved in oil (single gas/oil phase), bubbles of gas in oil (two phases), gas alone or gas condensate in the form of oil.

Clapeyron diagram – Liquid & gas equilibrium

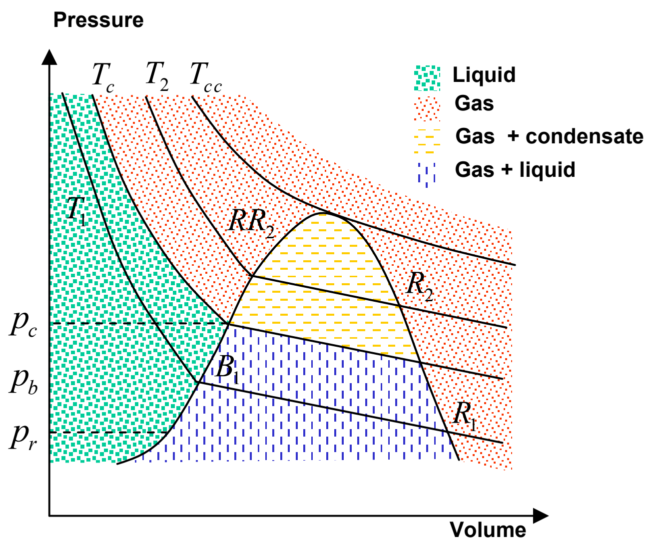


Figure 17 – Clapeyron's diagram

Let us consider a mixture of oil and gas in a monophasic state (gas is dissolved in oil) at a temperature T_1 and let us progressively decrease the pressure at constant temperature (**Figure 17**). The mixture remains liquid until point B_1 where a vapour phase appears. B_1 is called the bubble point. If we continue to decrease the pressure, the last oil drop will vaporise at point R_1 called the condensation

[4] The oil formation factor is the ratio between the liquid volume of oil in downhole conditions (reservoir pressure and temperature, gas dissolved in oil) and surface conditions (oil in standard conditions, oil freed from its dissolved gas). For water, there will only be a compressibility effect (no gas dissolved in the water).

point and a further decrease in pressure will bring the mixture to a single vapour phase. This behaviour is observed below a critical temperature T_C. Starting from an initial gas phase above the critical temperature T_C but below the critical condensation temperature T_{CC}, and by decreasing the pressure at constant temperature T_2, a liquid phase will appear at the retrograde condensation point RR_2. After a further decrease in pressure, the proportion of liquid (light oil called gas condensate) will increase then decrease and the last drop of liquid will disappear at the condensation point R_2. Below R_2 all the mixture will be in a gas state. For any temperature above T_{CC} only a gas phase will be observed, whatever the pressure.

Effect of free gas on flow dynamics

If a sample of oil (initial temperature below critical temperature) is depleted below the bubble pressure, dissolved gas is released. Like water, the presence of free gas in the porous space will strongly affect the effective permeability to oil and consequently production. These observations are quite similar to those already obtained with water and can be summarised as follows:

- Gas will only flow above a critical saturation S_{gc} (below S_{gc}, bubbles of gas remain trapped by capillary forces in the pore network). S_{gc} (a few %) is generally much lower than S_{wi} (typically a few %)
- For a gas saturation greater than S_{gc} the permeability to gas increases and the permeability to oil decreases
- For a maximum gas saturation equal to S_{gM} the permeability to oil becomes nil. S_{gM} is generally much smaller than $1 - S_{OR}$.

The relative permeabilities for the oil/gas couple are similar to those already obtained for the oil/water couple except that, in the initial state (i.e. above the bubble pressure), the gas saturation is nil and the relative permeability to oil is equal to 1.

Classification of reservoirs according to their initial state

The above considerations are used to classify various reservoirs according to their initial state:

- If the initial temperature is lower than the critical temperature ($T_i > T_c$) a gas cap will be present or not depending on the initial reservoir pressure:
    - If the initial reservoir pressure is equal to the bubble pressure ($P_i = P_b$), the liquid and gas phases are in equilibrium. The gas phase which is located at the top of the reservoir is called "primary gas cap" (see **Figure 4**). While the reservoir is being depleted, part of the gas freed by depletion moves up to the gas cap. The gas cap will have a top piston effect similar to the bottom piston effect in an active aquifer and will improve recovery providing the oil zone is thick enough to avoid gas coning into perforations,
    - If the initial reservoir pressure is greater than the bubble pressure ($P_i > P_b$), the reservoir is undersaturated. As depletion occurs, pressure decreases. However, the gas remains dissolved in the oil as long as the current reservoir pressure is higher than the bubble pressure. When the reservoir pressure drops below P_b, bubbles of gas appear in the oil, the oil viscosity increases (the gas/oil mixture is much less viscous than black oil) and the effective permeability to oil and the oil production decrease. Most of the

free gas is generally produced with the oil and penalises the production (sharp increase of the GOR, see next paragraph). However, in some exceptional cases, gas is not produced but segregated at the top of the reservoir to form a secondary gas cap supporting production

- If the initial temperature is between the critical and condensation critical temperatures ($T_c < T_i < T_{cc}$):
  - Above the retrograde condensation pressure, only gas will be produced,
  - Below the retrograde condensation pressure, both gas and gas condensate will be produced,
  - The initial state is generally close to the retrograde condensation point and gas condensate is produced from an early depletion stage
- If the initial temperature is higher than the condensation critical temperature ($T_i > T_{cc}$), the mixture will remain a gas whatever the pressure.

1.2.1 Gas-Oil Ratio (GOR)

In a similar manner to water, the increasing amount of gas produced while depletion occurs has to be continuously measured. Below the bubble point, part of the gas is free and circulates in the porous space whereas another part is still dissolved in the oil. A portion of the liberated gas may segregate under gravity and form a secondary gas cap whereas the rest is produced at the well. Parallel to the BSW, we define the GOR as the gas-oil ratio under standard conditions. The GOR can easily be calculated from each of the three fractions Q_o, Q_{gf}, Q_{gd} for the oil rate, free gas rate and dissolved gas rate respectively, under standard conditions:

$$GOR = \frac{Q_{gf} + Q_{gd}}{Q_O} = R_s + \frac{k_{rg}}{k_{ro}} \frac{\mu_o}{\mu_g} \frac{B_o}{B_g} \qquad (12)$$

where R_s is the dissolution fraction (volume of gas recovered per unit of oil under standard conditions) and B_g the gas volumetric factor (ratio between the downhole and surface gas flows). Apart from its miscibility in oil, gas strongly differs from water by its viscosity. Therefore, when the reservoir pressure drops below the bubble pressure, the gas which is typically 100 times less viscous than oil flows much more easily. A massive gas production can quickly kill a well. For an oil field, keeping the reservoir pressure above the bubble point will therefore be of a prime importance.