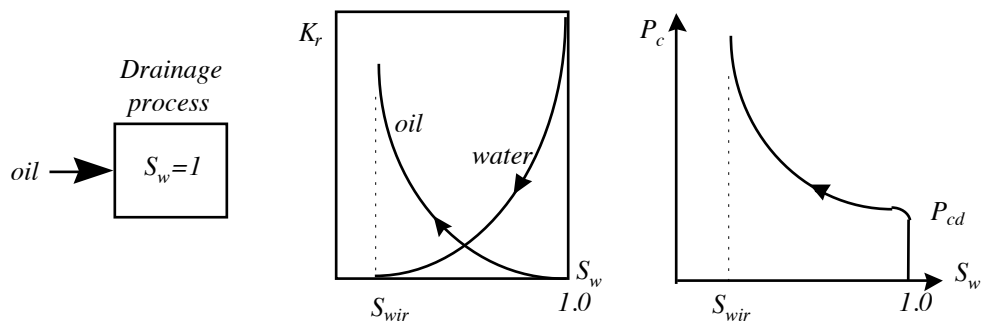


**REVIEW OF RELATIVE PERMEABILITIES AND CAPILLARY PRESSURES**

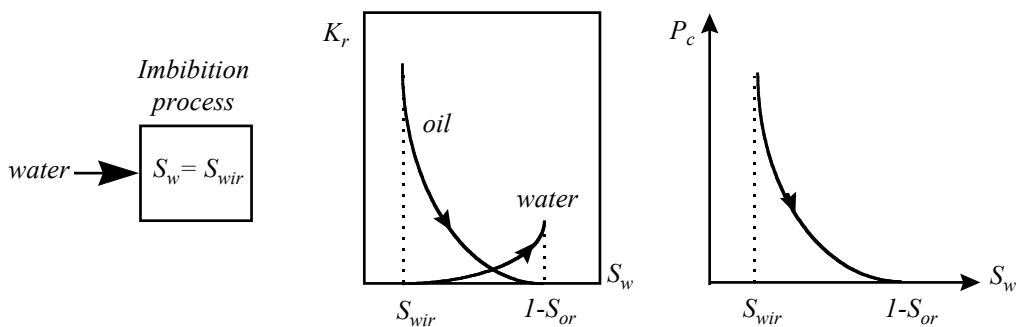
**Oil-water systems**

Both drainage and imbibition curves may be required in studies of oil-water system, depending on the process considered. Although most processes of interest involve displacement of oil by water, or imbibition, the reverse may take in parts of the reservoir due to geometrical effects, or due to changes in injection and production rates resulting in reversals of flow directions. Therefore, drainage curves may be required. Also, the initial saturations present in the rock will normally be the result of a drainage process at the time of oil accumulation. Thus, for initialization of saturations, the drainage capillary pressure curve is required.

Starting with the porous rock completely filled with water, and displacing by oil, the drainage relative permeability and capillary pressure curves will be defined:



Reversing the process when all mobile water has been displaced, by injecting water to displace the oil, imbibition curves are defined:



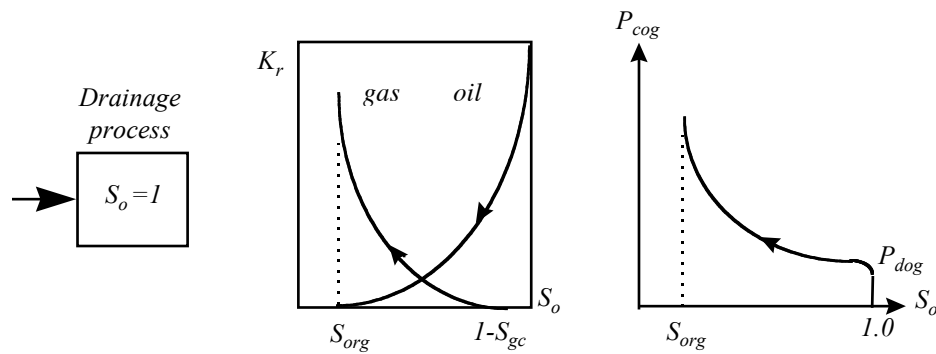
The above curves are typical ones for a completely water-wet system, which of course is not possible in reality. For mixed wet systems, the capillary pressure curve will have a negative part at high water saturation. The shape of the curves will depend on rock and wetting characteristics. Please see the article on wettability in Oilfield Review<sup>1</sup>

<sup>1</sup> Fundamentals of Wettability, Oilfield Review, 2007 (on webpage)

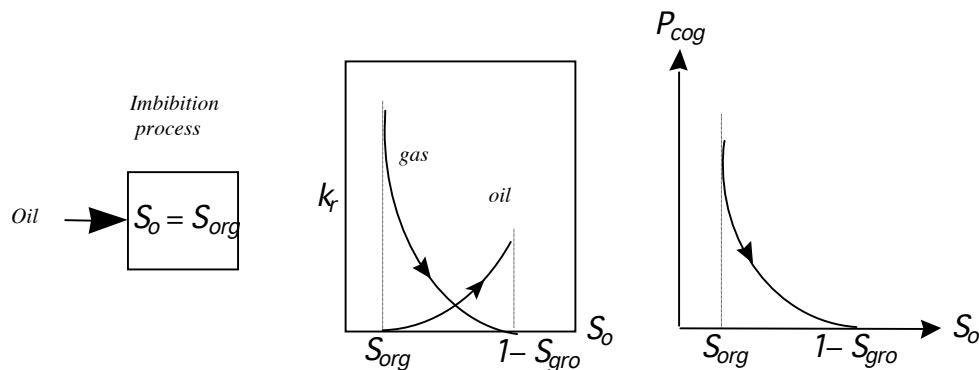
**Oil-gas systems**

Normally, only drainage curves are required in gas-oil systems, since gas displaces oil. However, sometimes reimbibition of oil into areas previously drained by gas displacement may happen. Reimbibition phenomena may be important in gravity drainage processes in fractured reservoirs.

Starting with the porous rock completely filled with oil, and displacing by gas, the drainage relative permeability and capillary pressure curves will be defined:



If the process is reversed when all mobile oil has been displaced, by injecting oil to displace the gas, imbibition curves are defined:



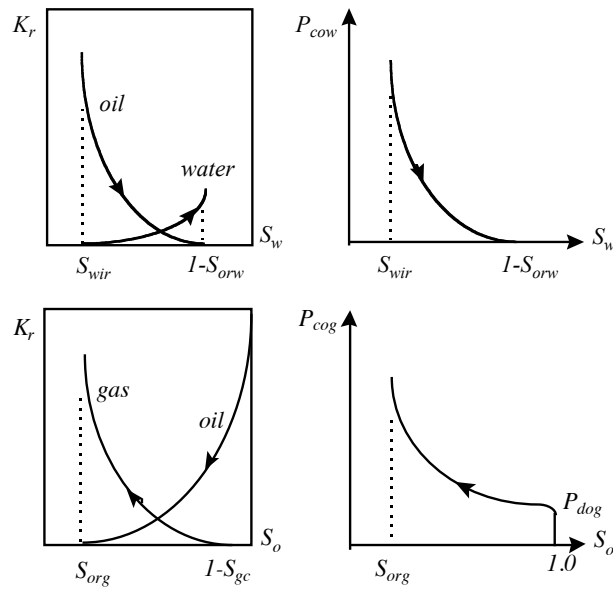
The shape of the gas-oil curves will of course depend on the surface tension properties of the system, as well as on the rock characteristics.

**Three phase systems**

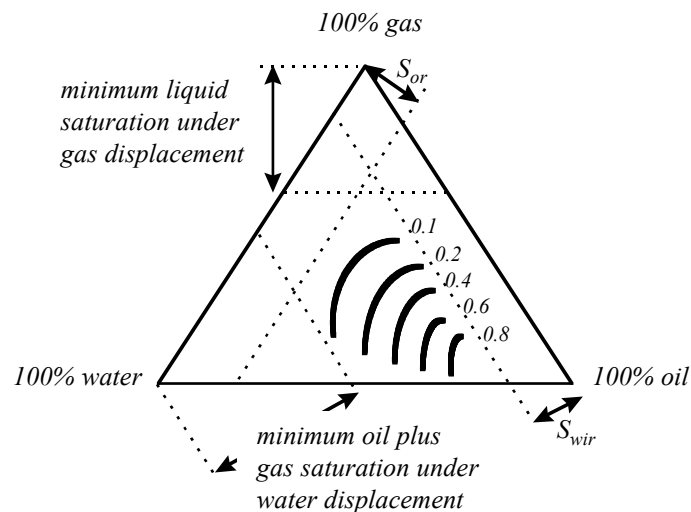
Since we now have three phases flowing, we need to define the relative permeabilities and capillary pressures anew. Although the following functional relationship not always are valid in practice, we will here use the conventional definitions for a completely water wet system with no contact between gas and water phases. Thus, the parameters below are functions only of the saturations indicated:

- $k_{rw}(S_w)$
- $k_{rg}(S_g)$
- $k_{ro}(S_w, S_g)$
- $P_{cow}(S_w)$
- $P_{cog}(S_g)$

Except for the relative permeability to oil,  $k_{ro}$ , these parameters may be measured in two-phase measurements since they depend on one saturation only. In the discussion of three-phase relative permeability to oil,  $k_{ro}$ , we will start with typical two-phase oil-water and oil-gas relationships:



The two oil relative permeability curves are two phase curves. However, as indicated above, in a three-phase flow situation, the oil relative permeability would be a function of both water and gas saturations. Plotting it in a triangular diagram, so that each saturation is represented by one of the sides, we can define an area of mobile oil limited by the system's maximum and minimum saturations (which not necessarily are constants). Inside this area,  $iso-k_{ro}$  curves may be drawn, as illustrated below:



In principle,  $k_{ro}$  may be measured in the laboratory. However, due to the experimental complexity of three-phase experiments, we most of the time construct it from two phase oil-water  $k_{row}$  and two phase oil-gas  $k_{rog}$ . The simplest approach is to just multiply the two:

$$k_{ro} = k_{rog} k_{row}$$

However, since some of the limiting saturations in three phase flow not necessarily are the same as for two phase flow, this model is not representative. For instance, the minimum oil saturation,  $S_{or}$ , for three phase flow is process dependent and a very difficult parameter to estimate.

The so-called *Stone-models* may be used for construction of three-phase relative permeability curves. A variety of other models exist, but these have been the most commonly used models. For the purpose of illustration, we will describe Stone's model 1 and model 2.

For **Stone's model 1**, we define normalized saturations as

$$S_{oD} = \frac{S_o - S_{or}}{1 - S_{wir} - S_{or}}$$
$$S_{wD} = \frac{S_w - S_{wir}}{1 - S_{wir} - S_{or}}$$
$$S_{gD} = \frac{S_g}{1 - S_{wir} - S_{or}}$$

Then we define the functions

$$\beta_w = \frac{k_{row}}{1 - S_{wD}}$$

$$\beta_g = \frac{k_{rog}}{1 - S_{gD}}.$$

The three phase oil relative permeability as constructed by Stone's model 1 may now be defined as

$$k_{ro} = S_{oD} \beta_w \beta_g$$

Please note that the above formulas assume that end point relative permeabilities are 1. If this is not the case, the relative permeability formula must be modified accordingly.

**Stone's model 2** does not require the estimation of  $S_{or}$ , as it attempts to estimate it implicitly by its formulation. The model simply is

$$k_{ro} = (k_{rog} + k_{rg})(k_{row} + k_{rw}) - (k_{rw} + k_{rg}).$$

In this model,  $S_{or}$  is defined at the point where  $k_{ro}$  becomes negative. The two models of Stone predict quite different  $k_{ro}$ 's in many cases, and one should be very careful in selecting which model to use in each situation.