Relative Permeability

Relative permeability is the ratio of effective permeability of a particular fluid at a particular saturation to the absolute permeability of that fluid at total saturation. Relative permeability is calculated as follows:

$$k_{r1} = -\frac{Q_1\mu_1}{k_{absolute}AdP/dx} \qquad k_{r2} = -\frac{Q_2\mu_2}{k_{absolute}AdP/dx}$$

Relative permeability of first phase (k_{r1}); Measured flux of first phase (Q_1); Viscosity of first phase (μ_1); Absolute permeability ($k_{absolute}$); Cross-sectional area (A); Pressure head (dP/dx)

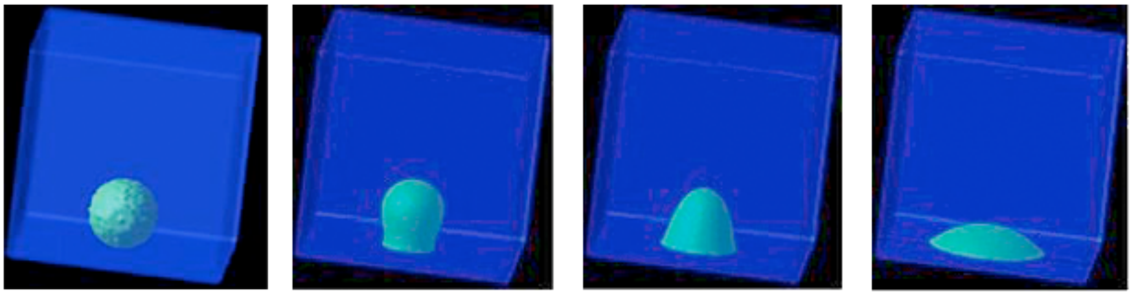
Relative permeability of second phase (k_{r2}); Measured flux of second phase (Q_2); Viscosity of second phase (μ_2)

If a single fluid is present in a rock, its relative permeability is 1.0. Relative permeability allows comparison of the different abilities of fluids to flow in the presence of each other, since the presence of more than one fluid generally inhibits flow.

Key parameters that affect relative permeability include:

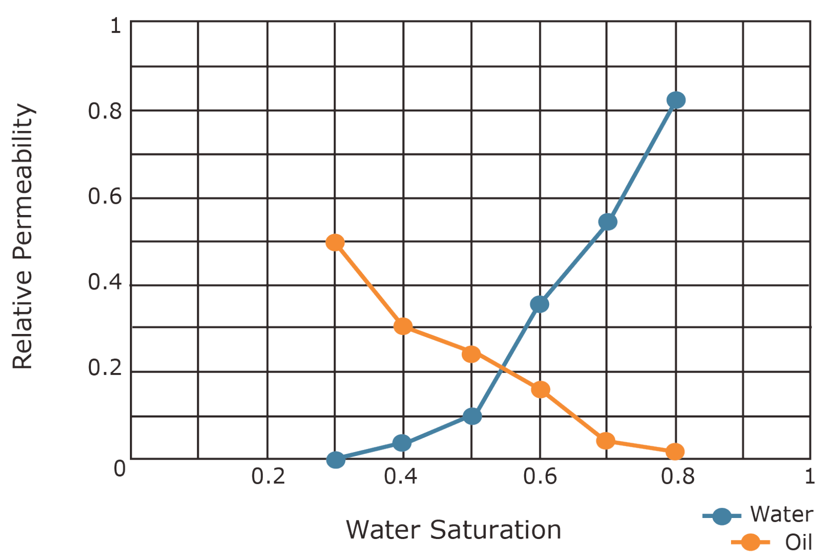
- The pore-space geometry (the distribution of large and small conduits and their sizes)
- Viscosity of the fluid
- Wettability of the mineral surface, and
- The surface tension between the fluid phases and between each fluid phase and the minerals.

These parameters define the wetting (or contact) angles, which are formed at an interface between fluid and mineral. A wetting angle is larger than 90 degrees if the fluid is wetting and smaller than 90 degrees if the fluid is non-wetting.



Wetting fluid gradually spreading along a flat surface. The final contact angle is about 140 degrees. The phenomenon is digitally simulated at Ingrain using the lattice Boltzmann method.

The slow multiphase viscous flow needed for relative permeability estimates is simulated using the lattice Boltzmann method (LBM). LBM mathematically mimics the equations of multiphase viscous flow by treating the fluid as a set of particles with certain interaction rules between the particles belonging to the same fluid, different fluids, and the fluids and pore walls.



Relative permeability curves in oil sand digitally simulated at Ingrain using the lattice Boltzmann method.

LBM directly simulates static and dynamic configurations of the contacts between the fluid phases and the pore walls by taking into account surface tension and contact angles. It allows for the estimation of irreducible water and hydrocarbon saturations.