

Fluid properties as function reservoir depth

The plots below give CO₂ density and viscosity as a function of depth [m]. Also, water viscosity is given in the same manner. The following assumptions are made:

We consider an offshore reservoir. At the sea bottom we have a pressure of 10 bars (100 m depth) and a temperature of 4 degrees Celsius. From here and downwards, we assume the pressure increases 1 bar per 10 meters, and the temperature increases 3,5 degrees Celsius per 100 meters.

Erik Lindeberg has developed a commercial Excel add-in that, amongst others, computes viscosity and density as function of pressure and temperature. It is then straightforward to plot the values as function of depth.

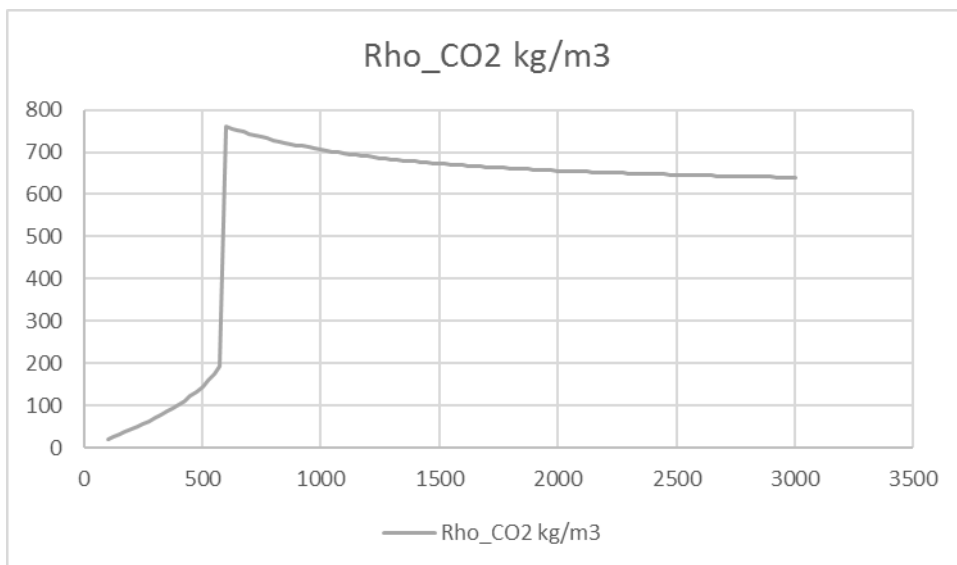


Figure 1 Mass density of CO₂ [kg/m³] as function of reservoir depth [m]. At approximately 650-700 m depth there is a phase transition where the gas condenses to a liquid phase. Thus, all CO₂ storage must take place at depths deeper than 600-700 m (here 1g of CO₂ occupies much less space than when it is in a gas phase). Note that CO₂ is only slightly lighter than water at these depths.

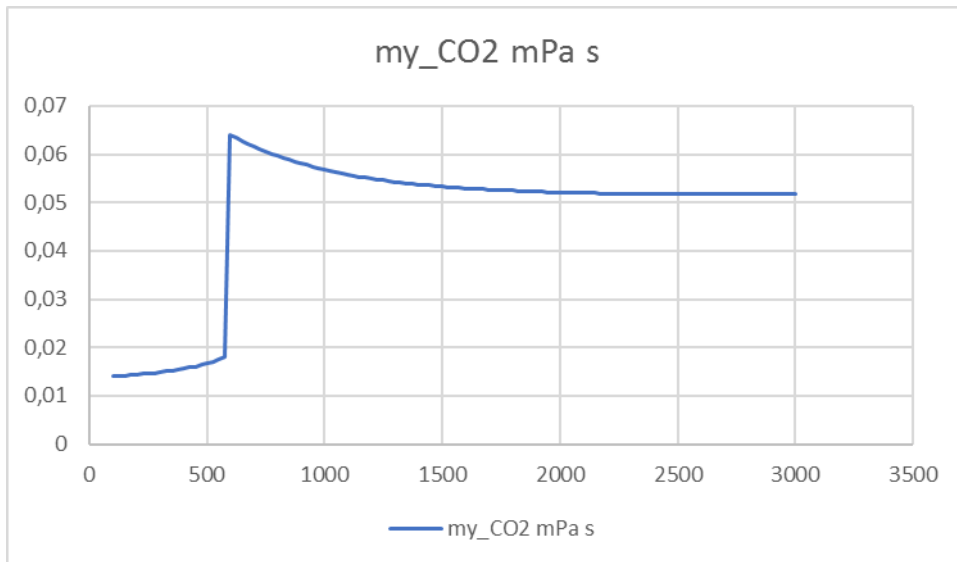


Figure 2 Viscosity of CO₂. as function of depth.

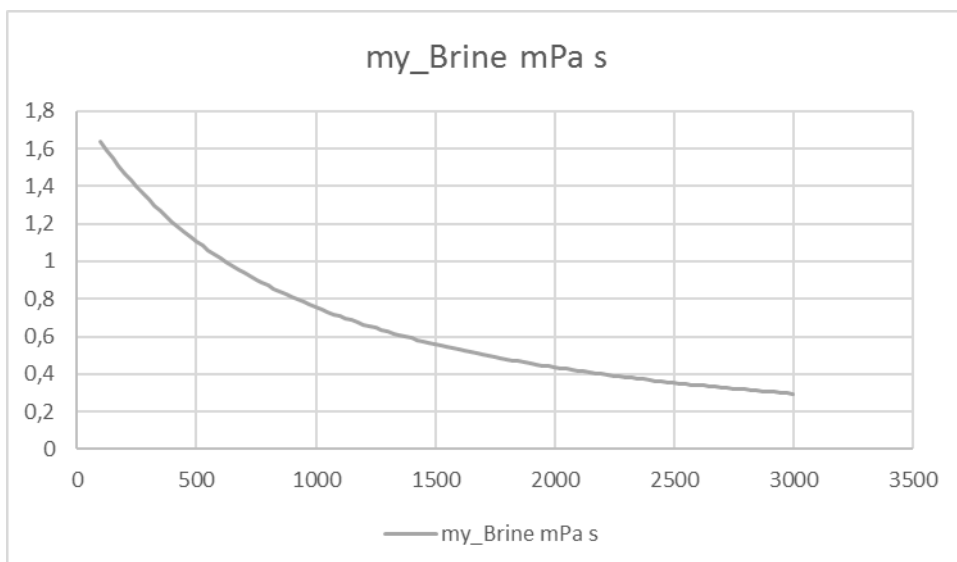


Figure 3 Viscosity of brine (water). It is mainly the increase in temperature that causes the decrease in viscosity. Brine mass density on the other hand is approximately constant (i.e. approximately incompressible).

We observe that the viscosity ratio $\frac{\mu_g}{\mu_w} \approx \frac{1}{10}$ at 1500m depth. Thus, essentially, gas mobility is ten times higher than that of water at this depth.

Other parameters

Absolute permeability varies over many magnitudes on all scales (mm scale to 100 m scale) in real reservoirs. The variation is particularly large in the vertical direction since sedimentary rocks have been deposited under different conditions through the geological era (the reservoir is a “stack of pancakes”).

A reservoir with permeability of order 1 Darcy is called a “good sand”. If you have a small piece ($\approx 1cm^3$) of such a rock, you will be able to blow through it.

For analysis and numerical simulations, $k = 0,1 \text{ Darcy} \approx 10^{-13} \text{ m}^2$ is a typical value to use for absolute permeability.

For capillary pressure, use, say $P_0 = 5 \text{ bars}$ to 10 bars as a reference maximal capillary pressure.

The total rate away from the wells (around the wells the rate is very high) can be estimated from Darcy's law in one dimension

$$u = -\frac{k}{\mu} \frac{dp}{dx} \approx -\frac{k}{\mu} \frac{\Delta p}{L}$$

Assume, for instance, a pressure drop $\Delta p \approx 75 \text{ bars}$ between an injection and production well (say we inject CO_2 and produce water to give space for the gas) with a well distance of 1 km (typical offshore well distance). For a 1700 m deep reservoir (or aquifer), water viscosity is approximately $\mu = 0,5 \text{ centiPoise} = 0,5 \text{ cP} = 0,5 \cdot 10^{-3} \text{ kgm}^{-1} \text{ s}^{-1}$. In the first phase of the CO_2 injection it is mainly water that is moved in the reservoir, so the water viscosity is the appropriate viscosity to use for estimation the total rate. Then, using a permeability value of $k = 0,1 \text{ Darcy}$, we find the volumetric flux density to be $u \approx 1,5 \cdot 10^{-6} \text{ m} / \text{s} = 13 \text{ cm} / \text{day}$.

Also, we include the phase diagram for CO_2 . Reservoir conditions are typically in the top right part, where the CO_2 is so-called supercritical.

Phase diagram for CO_2

Figure 1

