Quantification of viscous creep influence on storage capacity of caprock

Ludovic Räss¹, Roman Makhnenko², Yuri Podladchikov¹, and Lyesse Laloui²

¹Institute of Earth Sciences, University of Lausanne, Switzerland
²Laboratory of Soils Mechanics – Chair «Gaz Naturel» Petrosvibri, École Polytechnique Fédérale de Lausanne (EPFL), Switzerland

ABSTRACT

CO₂ storage security is largely influenced by the caprock integrity, especially at the early stages after the start of injection. The lower boundary of the caprock will then be in contact with carbon dioxide saturated pore water or pore fluid that consists almost of pure CO₂. Thermal and chemical interactions between the pore fluid and the caprock may change the material properties of the latter one. Geomechanical stability is also crucial for the caprock, since failure would potentially lead to a significant permeability increase and induced seismicity [1]. Considering clay-rich materials (e.g. shales) as potential seals has several advantages. In case the reservoir overpressure is not very important, the thermal, chemical and inelastic deformations of the clay-rich ductile formation might not affect the caprock integrity. Another advantage of considering clay-rich materials as a potential seal is that the upward movement of carbon dioxide through the pore system is resisted by capillary pressure; the breakthrough pressure (CO₂ entry pressure) for shale is on the order of 10 MPa. Even if clay-rich formations show interesting self-sealing features, their ease to flow (or creep) might become a serious issue when assessing long-term storage integrity of a reservoir. This viscous (time-dependent) deformation is therefore considered below.

The deformation of fluid-filled sedimentary rock is usually assumed to be poroelastic or poroelastoplastic. However, some observations show time-dependence in the response of subsurface material even at relatively low mean stresses and temperatures. By analogy with Biot’s poroelastic relationships, time-dependent or poroviscoelastic processes can be included in the constitutive equations [2,3]. It was found that the bulk viscosity \( \eta_\phi \) of water-saturated sedimentary rock decreases when the pore fluid pressure \( p^f \) to the total stress \( \bar{p} \) ratio increases. This viscosity becomes constant at \( \frac{p^f}{\bar{p}} > 0.6 \). For quartz-rich sandstone and carbonate-rich limestone, the bulk viscosity was found to be on the order of \( 10^{15} \text{ Pa} \cdot \text{s} \) and for a clay-rich material \( \sim 10^{12.5} \text{ Pa} \cdot \text{s} \) (Figure 1).

Swiss shale - Opalinus clay is considered to be a representative of the caprock material, because of its high (more than 55%) clay content and 30 nm dominant pore size, and hence high entry pressures (more than 8 MPa for liquid CO₂ at 20°C). Analysis of the poromechanical behavior of the low-permeable shale was performed by measuring drained, undrained, and unjacketed material
parameters. The bulk viscosity was evaluated by monitoring the undrained pore pressure build-up at constant mean stress at almost saturated (98%) and fully-saturated (with brine) conditions. It was found to be $\approx 10^{13.5}$ Pa\(\cdot\)s. This bulk viscosity value is between those of clay-rich material on one side and quartz- and calcite-rich materials on the other side (other minerals that form the shale).

The observation and measurements inferred from the lab are then used to constrain the important parameters of a currently developed TwoPhase numerical model [4]. Poroelastic parameters together with effective bulk viscosities of major reservoir rocks allow the model to predict the time evolution of the porosity of a fluid saturated porous rock sample. The nonlinear poroviscoelastic closed set of equations [3] is solved with an iterative finite-difference scheme in three-dimensions (3D) on an ultra-high resolution. Nonlinearities and residuals are monitored and treated in an appropriate way. Numerical resolution of more than 1.5 billion grid points is reached by using GPUs in parallel on the memory bandwidth optimized computing cluster octopus at ISTE, Unil.

The numerical simulations show elongated pipe features developing over time due to highly focused fluid flow through the deforming porous media (Figure 2). Channel formation, and thus asymmetry in decompaction versus compaction rates is the result of viscosity dependence on $p^f / \bar{p}$ ratio. The effective viscosity drops in region where the pore fluid pressure gets closer to the total stress. The created channels are referred to porosity waves, as the solid grains only get displaced very locally, allowing the fluid to go through the porous media in a wave like motion.

![Figure 1. Measured bulk viscosity of shaly caprock with respect to other sedimentary formations.](image)

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We show that viscous effect should not be excluded when assessing long-term behavior of clay-rich materials, such as shales [5]. The modelling results using parameters from the laboratory experiments predict that nonlinear porosity-dependent permeability can increase up to three orders of magnitude within the porosity waves. Long-term projections for storage behavior should therefore include time-dependent (viscous) deformation of the potential caprocks.

REFERENCES


