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Lithological controls on matrix permeability of organic-rich shales: An experimental study

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Despite considerable gas-in-place (GIP) estimations for shale gas plays, these complex heterogeneous reservoirs require innovative exploration and completion strategies to produce natural gas economically. Economic gas flow rates in these reservoirs, which commonly have permeability coefficients down to the nDarcy-range, are still technically difficult to achieve, partially due to the poor understanding of the fluid transport processes within the fracture and matrix systems of these lithotypes. This contribution will present results from an ongoing laboratory study investigating the fluid transport properties in the matrix system of the organic-rich shales, differing in pore network characteristics (porosity, pore size distribution), mineralogy (calcite, clay, quartz), TOC content (3-14 %) and maturity (0.6-2.4 %R_o).

Single- and two-phase fluid flow experiments were conducted within the frame of the GASH project (www.gas-shales.org). Gas (He, Ar, CH_4) and water flow properties were determined at effective stresses ranging between 8 and 37 MPa and temperatures of 25 and 45˚C. The effects of different controlling factors/parameters on the conductivity were analysed and will be discussed:

- Influence of maturity on intrinsic permeability: Among the sample suite studied, the lowest permeability coefficients in parallel and perpendicular directions were measured at intermediate maturity levels (oil-window; 0.85 - 1.05 %R_o).
- Poro-perm-relationship: The Klinkenberg-corrected gas permeability coefficients increased significantly with porosity (4-16 %) ranging between $4 \cdot 10^{-22}$ and $9.7 \cdot 10^{-17} m^2$.
- Anisotropy of permeability: Permeability coefficients measured parallel to bedding were more than one order of magnitude higher than those measured perpendicular to bedding. The permeability anisotropy appeared, furthermore, to be controlled by the mineral composition.
- Influence of permeating fluid on intrinsic permeability: Permeability coefficients measured with He were consistently up to five times higher than those measured with Ar and CH_4 under similar experimental conditions. A substantial discrepancy between Klinkenberg-corrected gas permeability coefficients and water permeability coefficients ($0.5\text{-}10 \cdot 10^{-21}$ m^2) was observed for both immature and overmature samples.
- Influence of moisture on intrinsic permeability: Klinkenberg-corrected gas (He, Ar, CH_4) permeability coefficients measured on dried samples were about six times higher than those measured on as-received sample (moisture content: 1.1%).
- Stress dependence of permeability: The rate of permeability reduction with increasing effective stress depended significantly on orientation and moisture content. The reduction rate was, however, comparatively independent of the type of permeating gas (He, Ar, CH_4). The most significant permeability reduction with effective stress was observed for as-received sample (moisture content: 1.1 wt%, on as-received basis), compared to those which were dried (105 ˚C, vacuum, overnight) before the tests.
- Capillary gas breakthrough measurement with helium on an immature shale sample occurred between 5.5 and 6.2 MPa. The shut-off pressure (imbibition path) was approximately half the breakthrough pressure ($\sim$2.5 MPa). The effective permeability coefficient was $5.5 \cdot 10^{-21}$ m^2 at a differential pressure of 14 MPa.