
Contribution ID: **69** Type: **Poster Presentation**

# Stress Sensitivity of Fracture Permeability in Shale Oil Reservoirs under Fluid-Solid Coupling

*Wednesday, 15 May 2024 16:10 (1h 30m)*

Introduction
Natural fractures play a crucial role in serving as the primary conduits for seepage in reservoirs, particularly in shale oil reservoirs characterized by ultra-low permeability (Zou et al., 2009; Sun et al., 2023; Bai et al., 2023). Despite the acknowledged significance of these fractures, a notable gap exists in understanding the stress sensitivity of fracture permeability in shale oil reservoirs. Addressing this knowledge deficit, our approach comprehensively investigates natural fracture permeability. This encompasses a combination of mechanical and CT scanning tests, coupled with advanced numerical modeling techniques, to bridge the existing gap and enhance our understanding of fracture permeability in shale oil reservoirs.
Methodology
We conducted multi-scale CT scanning at 25 mm and 100 mm scales, followed by the establishment of a numerical model (Fig. 1a-d). The models were constructed with specific parameters: a density of 2.65 $g/cm^3$, a tensile strength of 8.00 MPa, a compressive strength of 46.67 MPa, a Young's modulus of 1.33 GPa, and a Poisson's ratio of 0.21. The applied confining pressure during the numerical simulation varied from 2 MPa to 10 MPa. This study introduces a fully coupled simulation that accounts for the reciprocal interactions between fluids (CH4) and solids in shale, employing COMSOL Multiphysics.
Results and Discussion
The fracture permeability of the 100 mm core ranged from 2.04×10^4 $\mu m^2$ to 8.67×10^4 $\mu m^2$, while that of the 25 mm core decreased from 1.3×10^3 $\mu m^2$ to 5.45×10^2 $\mu m^2$. Remarkably, the fracture permeability of the 100 mm core was nearly ten times higher than that of the 25 mm core (Fig. 1e). Despite the substantial difference in fracture size between the two models, their permeability exhibited a similar changing trend under varying confining pressures. Additionally, the permeability demonstrated a linear decrease with increasing confining pressure, evidenced by a reduction of 2.35 and 2.39 times the initial values for the 100 mm and 25 mm shale cores, respectively. These findings suggest a consistent stress sensitivity of fracture permeability across different fracture scales. However, it is important to note that fractures with smaller scales may experience complete closure under higher confining pressures, resulting in the total loss of permeability.

Fig. 1. A detailed description of the model creation process based on CT scanning data shale cores. (a) Identifying fractures from scanned sections, (b) segmenting the data based on specific thresholds, (c) reconstructing a 3D model structure, and (d) refining appropriate grids based on the size of the structure. (e) The fracture permeability varies vs. the confining pressures.

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## References

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## Conference Proceedings

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**Session Classification:** Poster

**Track Classification:** (MS17) Complex fluid and Fluid-Solid-Thermal coupled process in porous media: Modeling and Experiment