Gas relative permeability and its modeling in tight and ultra-tight porous rocks

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BACKGROUND

Factors affecting gas permeability in tight media

- Connectivity
- Pore-throat size distribution
- Slip flow and Knudsen diffusion
- Tortuosity
- Porosity
- Pore shape geometry
- …

Theoretical upscaling techniques

- Bundle of capillary tubes approach
- Effective-medium approximation (EMA)
- Critical path analysis (CPA)
- Perturbation theory
- Volume averaging method
- …

PURPOSES AND ASSUMPTIONS

Objectives

- ✓ To evaluate EMA's reliability in the estimation of gas transport and more specifically gas relative permeability k_{rg} in tight and ultra-tight porous rocks.
- ✓ To estimate k_{rg} from mercury intrusion capillary pressure curve or pore-throat size distribution.
- ✓ To compare EMA results with pore-network model simulations and experiments.

Assumptions

- ❑ Pores can be either cylindrical or slit-shaped.
- ❑ Gas transport is dominated by two mechanisms contributing in parallel: (1) slip flow, and (2) Knudsen diffusion.
- ❑ Contact angle is about 140° for mercury.
- ❑ The air-mercury interfacial tension is 485 mN/m.

MATERIALS AND METHODS

Hydraulic flow in a tube

$$g_h = \beta F \frac{\pi R^4}{8\mu l} \qquad F = 1 + \left(\frac{8\pi R_g T}{M_m}\right)^{0.5} \frac{\mu}{pR}\left(\frac{2}{TMAC} - 1\right)$$

β is the gas compressibility factor.

Molecular flow in a tube

$$g_m = \alpha \pi R^2 \sqrt{\frac{R_g T}{2\pi M_m}}$$

$$\alpha = 1 + y^2 - y\sqrt{1+y^2} - \frac{\left[(2-y^2)\sqrt{1+y^2} + y^3 - 2\right]^2}{4.5y\sqrt{1+y^2} - 4.5\ln\left(y + \sqrt{1+y^2}\right)}$$

$y = l/(2R)$.

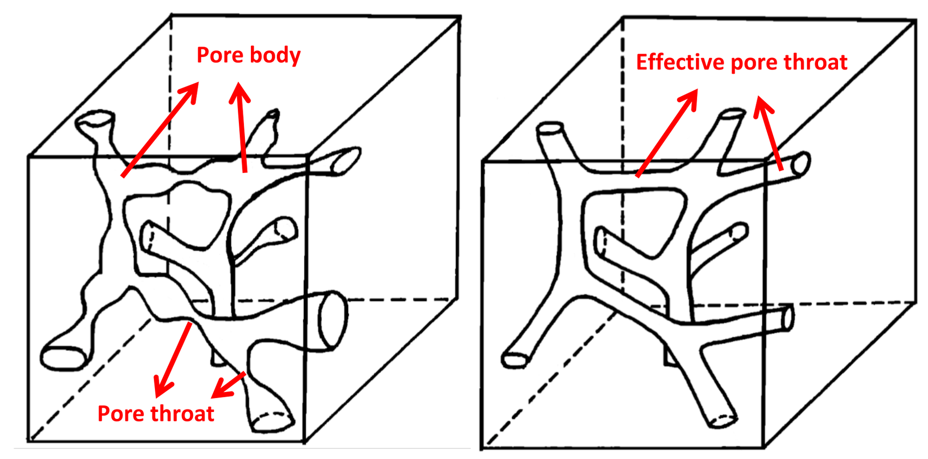
Assuming that gas flow is mainly controlled by hydraulic and molecular flow (two mechanisms contributing in parallel) in a single cylindrical nanotube with radius R and length l, the total conductance, g_t, in the pore throat is given by

$$g_t = g_h + g_m = \beta F \frac{\pi R^4}{8\mu l} + \alpha \pi R^2 \sqrt{\frac{R_g T}{2\pi M_m}}$$

The effective-medium approximation (EMA)

An upscaling technique from statistical physics appropriate in homogeneous and relatively heterogeneous porous rocks. Effective conductance can be determined from the following EMA governing equation:

$$\int_{g_{tmin}}^{g_{tmax}} \frac{g_e(S_g = 1) - g_t}{g_t + \left[\frac{1 - S_{gc}}{S_{gc}}\right] g_e(S_g = 1)} f(g_t)\, dg_t = 0$$



Single-phase permeability

The upscaled EMA permeability model is (Ghanbarian and Javadpour, 2017):

$$k = \frac{2 r_e \mu M}{3 R_g \rho} \frac{\phi}{\tau} \left(\frac{8 R_g T}{\pi M}\right)^{0.5} + F \frac{\phi}{C_s \tau} \frac{r_e^4}{\langle r_b^2 \rangle} \qquad \mathrm{TMAC} = 1 - \log(1 + K_n^{0.7}) \qquad K_n = \frac{k_B T}{2\sqrt{2}\pi d_m^2 p r_e}$$

Gas relative permeability

For partially-saturated conditions, one has

$$\int_{g_{tmin}}^{g_t} \frac{g_e(S_g) - 0}{0 + \left[\frac{1 - S_{gc}}{S_{gc}}\right] g_e(S_g)} f(g_t)\, dg_t + \int_{g_t}^{g_{tmax}} \frac{g_e(S_g) - g_t}{g_t + \left[\frac{1 - S_{gc}}{S_{gc}}\right] g_e(S_g)} f(g_t)\, dg_t = 0$$

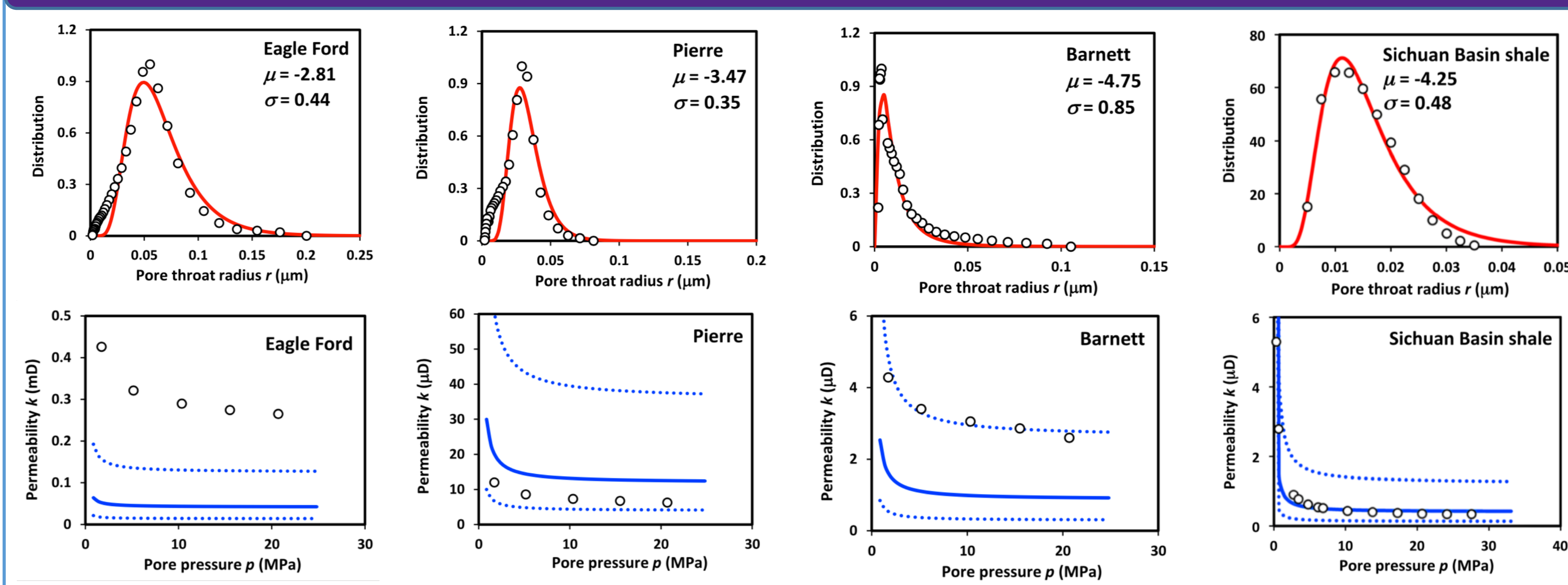
Since gas permeability is proportional to the effective conductance, we define k_{rg} as (Ghanbarian, 2018)

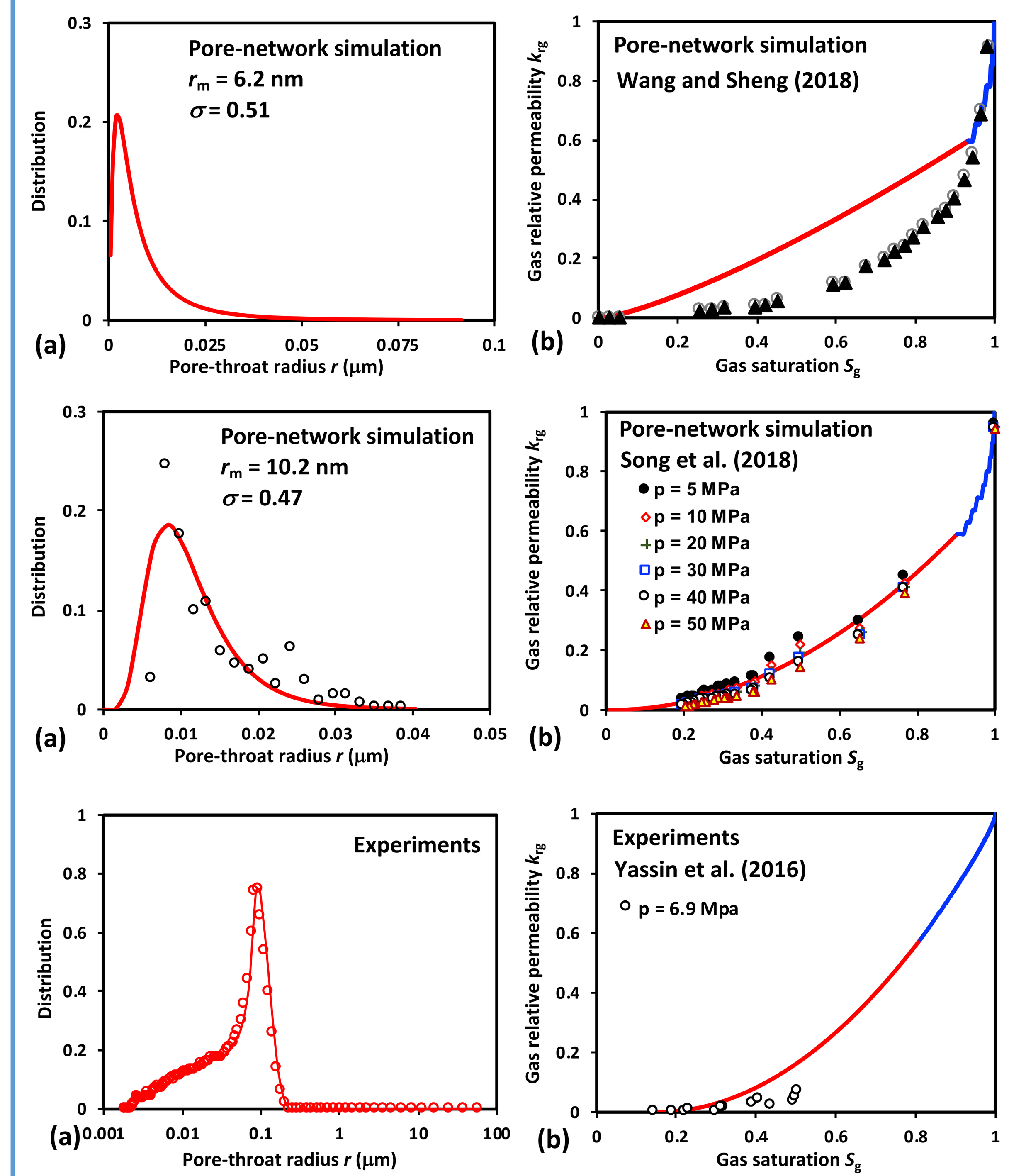
$$k_{rg} = \frac{k_g(S_g)}{k_g(S_g = 1)} = \frac{g_e(S_g)}{g_e(S_g = 1)}$$

We use the EMA at high to intermediate gas saturations and apply the following universal power-law scaling from percolation theory at low gas saturations near S_{gc}

$$k_{rg} = k_0 (S_g - S_{gc})^2, \qquad S_g > S_{gc}$$

RESULTS





CONCLUSION

- ❑ Comparison with 2D pore-network simulations showed that the proposed model estimated gas relative permeability well at high gas saturations. However, it overestimated k_{rg} at intermediate saturations.
- ❑ By comparison with 3D pore-network simulations, we found that our model estimated k_{rg} over the entire range of gas saturation accurately.
- ❑ Using experimental data reported in Yassin et al. (2016) including samples from the Western Canadian Sedimentary Basin, we showed that our model estimated k_{rg} reasonably well, although it slightly overestimated k_{rg}.

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