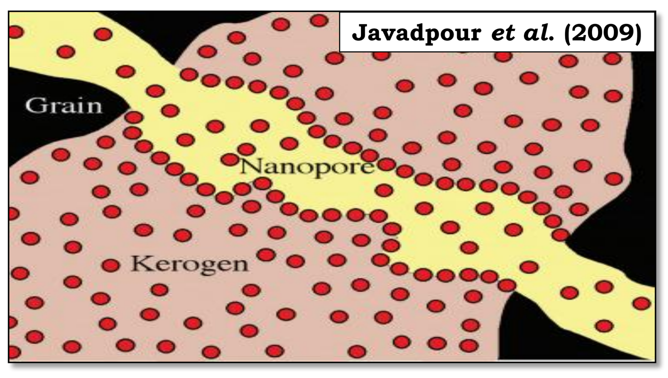
Numerical Study of Flux Models for CO_2: Enhanced Natural Gas Recovery & Potential CO_2 Storage in Shale Gas Reservoirs



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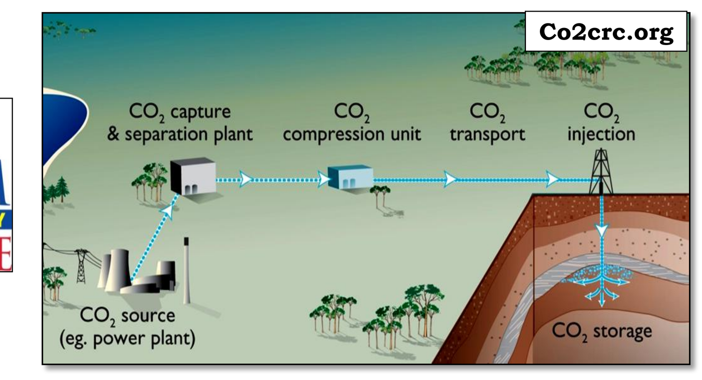


Introduction

Gas production from gas shale has become a major source of fossil energy in United States. Because of low porosity and ultra-low permeability, shale reservoirs often reach peak production in a very early stage as compared to the conventional sandstone reservoirs. Various attempts have been made to describe the fluid flow behavior in these reservoirs. Slip flow, diffusion and adsorption/desorption are mainly considered as primary flow mechanisms in shale nano-pores while Darcy flow can be attributed for flow in natural fractures. The emphasis of this research is to model a shale reservoir using COMSOL Multiphysics. This poster focuses on comparing the performance of various specie transport flux models by accounting for inter-molecular interactions and gas-rock interactions.

Objectives

- Investigate mechanisms of gas transport in shale nano-scale pores to develop better insight on competitive adsorption of CO_2 on pore walls compared to CH_4 and other hydrocarbon gases.
- Develop a rigorous modeling framework that accounts for diffusion, adsorption, and Darcy flow in a shale reservoir dual-pore system using different flux models.
- Compare predictions of species transport for different flux models and establish an appropriate methodology for validation using data from an actual reservoir.

Governing Equations

Species Mass Balance for Dual Porosity Model

Matrix

$$\frac{\partial\left(\rho\varphi+\rho_q(1-\varphi)\right)_i}{\partial t}+\nabla.(\rho u)_{m,i}+Q_{mf,i}=0$$

$$Q_{mf,i}=\alpha^*(\rho u)_{i_{matrix-fracture}}$$

*Using Lim and Aziz (1994) transfer shape factor

Fracture

$$\frac{\partial(\rho\varphi)_i}{\partial t}+\nabla.(\rho u)_{f,i}-Q_{mf,i}=Q_{g,i}$$

where: i = 1 for Methane (CH_4)

i = 2 for Carbon Dioxide (CO_2)

$$\rho_i=G_iP_i \text{ where } G_i=\frac{M_i}{Z_iRT} \text{ and } P_i=x_iP$$

Extended Langmuir Adsorption Isotherm

$$q_{ads,i}=\frac{V_{L,i}B_iP_i}{1+\sum_{j=1}^{2}B_jP_j} \Rightarrow \rho_{q,i}=\frac{\rho_sM_i}{V_{std}}*q_{ads,i}$$

Modeling Shale Reservoir for CO_2-EGR

Table 1. Reservoir Parameters

Molar mass of methane, kg/mol	0.016
Molar mass of carbon dioxide, kg/mol	0.044
Matrix permeability, m^2	1.0×10^{-14}
Fracture permeability, m^2	1.0×10^{-10}
Matrix porosity	8.0 %
Fracture porosity	1.0 %
Rock density, kg/m^3	2560
Absolute temperature, K	353
Gas deviation factor (Z_s) of mixture in shale	1.0
Rock compressibility, Pa^{-1}	1×10^{-5}
Langmuir pressure of CH_4*, Pa	3.05×10^{6}
Langmuir pressure of CO_2*, Pa	1.68×10^{6}
Langmuir volume of CH_4*, std.m^3/kg	9.80×10^{-4}
Langmuir volume of CO_2*, std.m^3/kg	1.91×10^{-3}

*H. Sun *et al.*, 2013, *Intl Journal of Greenhouse Gas Control* 19 406-418

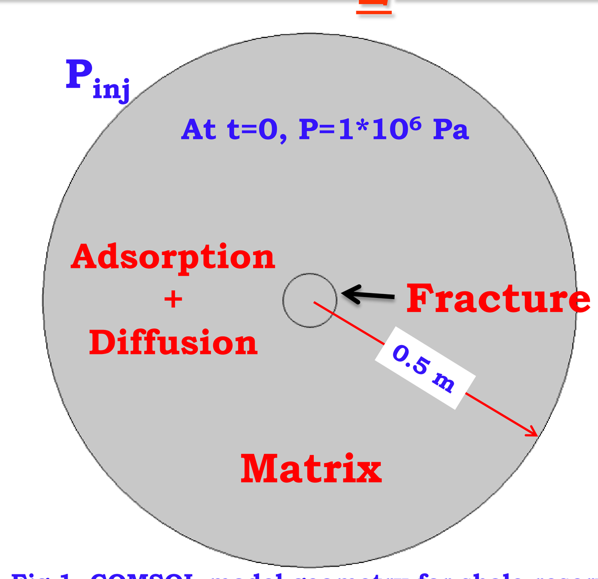


Fig.1 COMSOL model geometry for shale reservoir

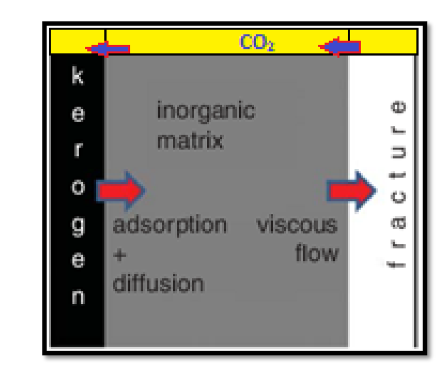


Fig.2 Schematic of gas flow in shale reservoir

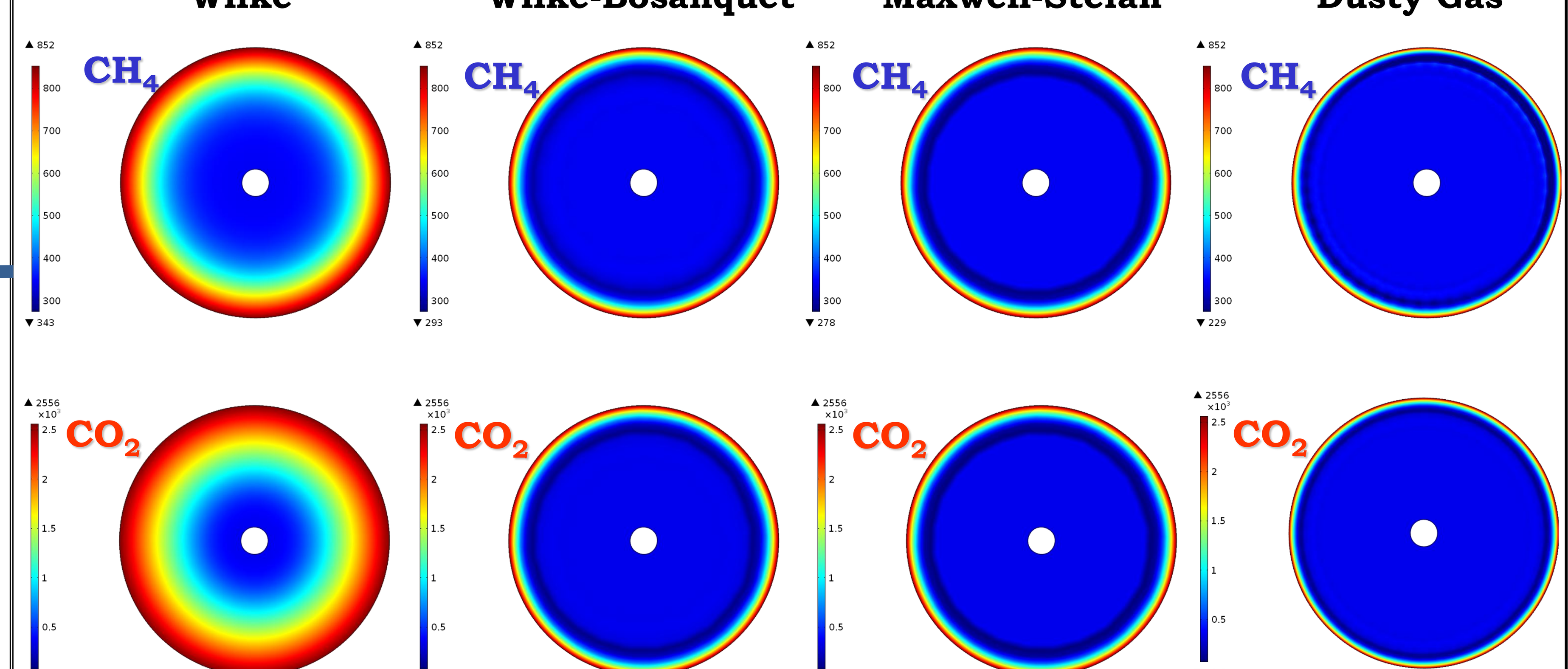
Assumptions

- Gas species follow the ideal gas law. [Note: Real gas can be modeled using an EOS]
- Reservoir temperature remains constant.
- Single phase gas flow exists.
- No variation in rock compressibility.
- Horizontal and vertical permeabilities are assumed to be equal (isotropic media).
- Porosity of both media (matrix and fracture) remain constant.

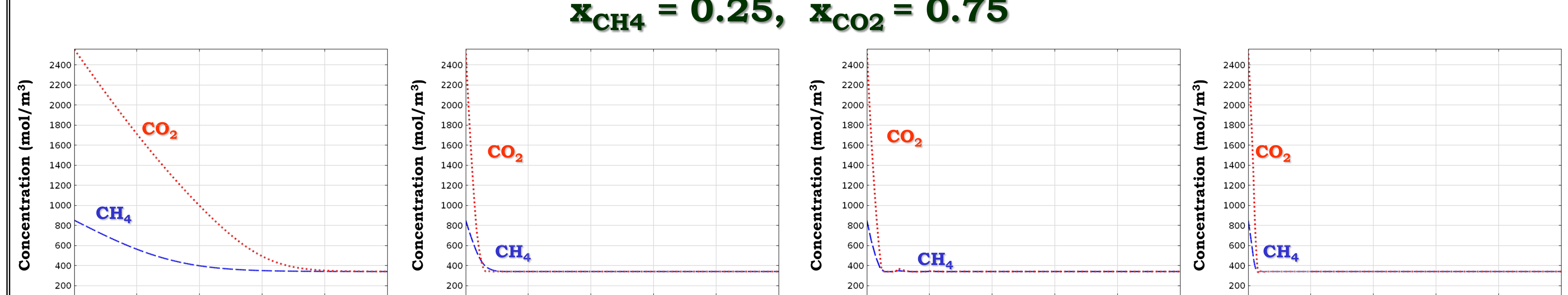
Results for Binary Component Model

$x_{CH4} = 0.25, \; x_{CO2} = 0.75$

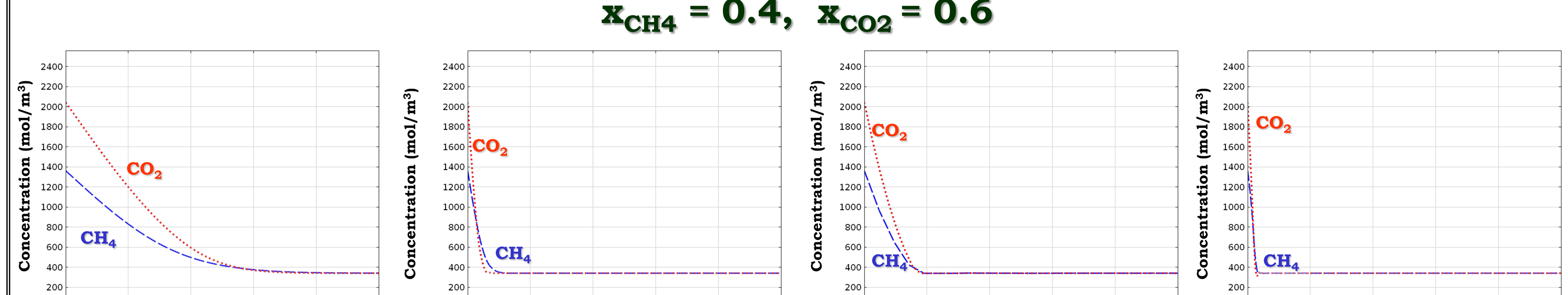
Wilke | Wilke-Bosanquet | Maxwell-Stefan | Dusty Gas



$x_{CH4} = 0.25, \; x_{CO2} = 0.75$



$x_{CH4} = 0.4, \; x_{CO2} = 0.6$



Diffusion Flux Models

Wilke Model

$$N_i=\left(-D_{ei,m}\nabla C_i\right) \quad \text{where} \quad D_{ei,m}=\frac{1}{\left(\sum_{j=1,j\neq i}^{n}\left(x_j/D_{ij}^e\right)\right)}$$

Wilke-Bosanquet Model

$$N_i=\left(-D_{i,eff}\nabla C_i\right) \quad \text{where} \quad \frac{1}{D_{i,eff}}=\frac{1}{D_{ei,m}}+\frac{1}{D_{ei,k}}$$

Maxwell-Stefan Model

$$N_i=\frac{-\nabla C_i+\sum_{j=1,j\neq i}^{n}\frac{x_iN_j}{D_{ij}^e}}{\sum_{j=1,j\neq i}^{n}\frac{x_j}{D_{ij}^e}}$$

$$x_i=\frac{P_i}{\sum_{j=1}^{2}P_j}$$

$$C_i=\frac{P_i}{Z_sRT}$$

Dusty-Gas Model

$$N_i=\frac{\sum_{j=1,j\neq i}^{n}\frac{x_iN_j}{D_{ij}^e}-\frac{C_iv^*}{D_{ei,k}}-\nabla C_i}{\sum_{j=1,j\neq i}^{n}\frac{x_j}{D_{ij}^e}+\frac{1}{D_{ei,k}}}$$

Dimensionless Velocity

$$V^*=-\frac{\varepsilon\, d_{pore}^2}{32\,\tau\,\mu}\nabla P$$

d_{pore} = 100 nm

ε = 0.04

τ = 4

*Reference: M. E. Davis, (1982) *Chem. Eng. Sci.*, 37(3) pp 447-452

1. Binary Diffusion Coefficient (Reid *et al.* 1972)
2. Knudsen Diffusion Co-fficient (Sun *et al.* 2013)

Conclusions

- The various flux models show that the pressure wave propagates at a higher rate with the Wilke model compared to other flux models for both gas species. This shows the importance of Knudsen diffusion for creating shale nano-pore fluid flow models.
- Binary diffusion and adsorption play the key roles for the fluid flow in shale nano-pores by promoting a hopping mechanism in vicinity of pore walls. Shale rock has higher adsorption preference for linear CO_2 molecules as compared to tetrahedral C_1 molecules, which causes liberation of methane from pores where the pressure wave cannot reach.
- An increase in the methane concentration at injection points causes the pressure wave to propagate faster in the model as compared to lower concentrations of methane. This shows that the displacement efficiency of methane in shale is higher than carbon dioxide. Therefore, to achieve higher production, it would be advisable to seal off the well after injection of CO_2 for a particular time and then restart the production.
- This model can be extended by including other physical phenomena, such as fracture flow mechanics, shale heterogeneity, other gas species and multi-phase flow due to variable pressure, temperature and water concentration.