Integrated Multiscale Research of Fluid Flow in Shale: Molecular-to-Core Scales*

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Search and Discovery Article #42244 (2018)**
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See similar article Search and Discovery Article #41780 (2016)

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Abstract

One of the great challenges in modeling fluid flow in shale system is the existence of heterogeneities at different scales. While the goal is to predict gas and oil production from a well, we learned that processes at the very small scale control the flow. At the molecular scale the interaction of fluid molecules with pore inner walls control the process. We have measured interactive forces and performed extensive molecular dynamics simulations (MD) to study fluid molecules interactions with pore walls. At the pore scale, SEM images reveal the locale of the pores and by using image analysis we extracted important information about pore geometries. We also utilize high pressure mercury injection capillary pressure (MICP) and low pressure nitrogen sorption tests to learn about porosity and pore size distribution in shale samples. Information about interactive forces, pore size distribution, pore geometry, porosity, and TOC are input data in our models and apparent permeability is the model prediction. We present a realistic model that honors heterogeneity of organic matter patchiness and its effect on apparent permeability. We validated our model using a set of detailed experimental data on shale samples. These results suggest that heterogeneity at small scale could affect the permeability at core scale and pore sizes corresponding to each compartment; organic and inorganic should be considered to estimate permeability. The model results also confirm permeability enhancement during sorption process in organic matter below critical sorption pressure.

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AAPG, Salt Lake City, UT
May 22, 2018

Mudrock Systems Research Laboratory MSRL

Bureau of Economic Geology

$The value of a reservoir$

Oil & gas reserve

- Pores and porosity
  - SEM, MICP, He, N2 sorption,
- Oil-in-place
  - Saturations
  - Preferential adsorption of HC components
- Gas-in-place
  - Pressurized gas in pores
  - Sorbed gas
  - Lost gas estimation

Oil & gas production, fracture fluid injection

- Effective liquid permeability
  - Water and HC slip flow
  - Fracture fluid loss
- Effective gas permeability
  - Langmuir slip & Knudsen diffusion
  - Gas perm measurement & models

Key research questions related to storage and production of mudrock

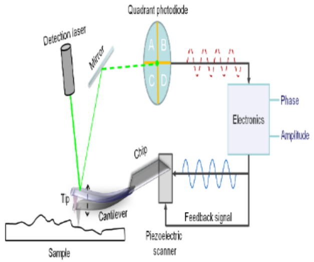
What are the sizes of the pores and their connectivity?

How does fluid flow in such pore system?

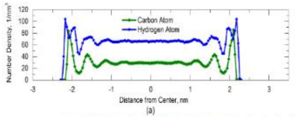
Molecular-to-core plug

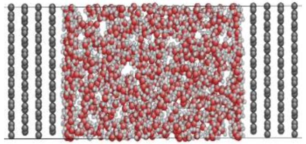
Subpore

Atomic force microscope (AFM) study for detailed study of fluid molecule interactions with pore inner walls



Molecular dynamics (MD) study of fluid molecules and pore inner walls

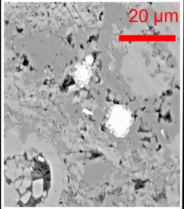




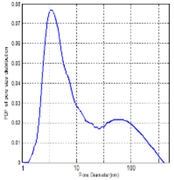
Metrology developed.

Pore

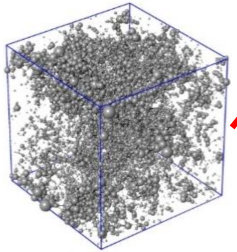
SEM study of organic, inorganic, and pores

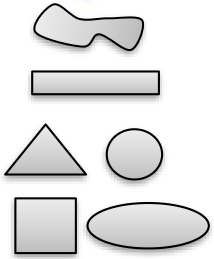


N2 adsorption data for pore size distribution



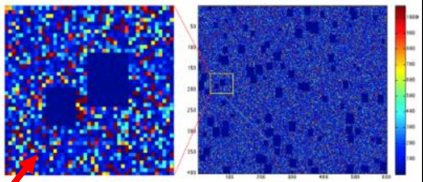
Pore network

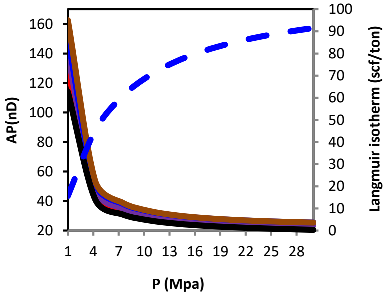




Network of pore networks

Stochastic permeability model to relate subpore interactions and information from SEM images, N2 adsorption, etc

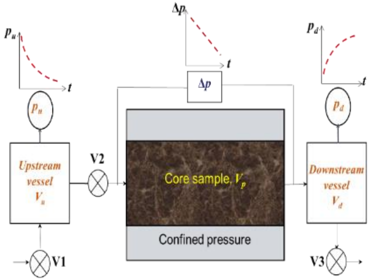




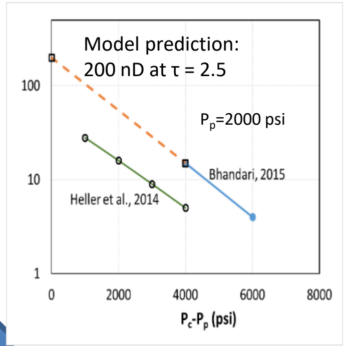
Model developed. New version with geomechanical effects.

Core plug

Pulse decay permeability measurements. Effect of effective stress

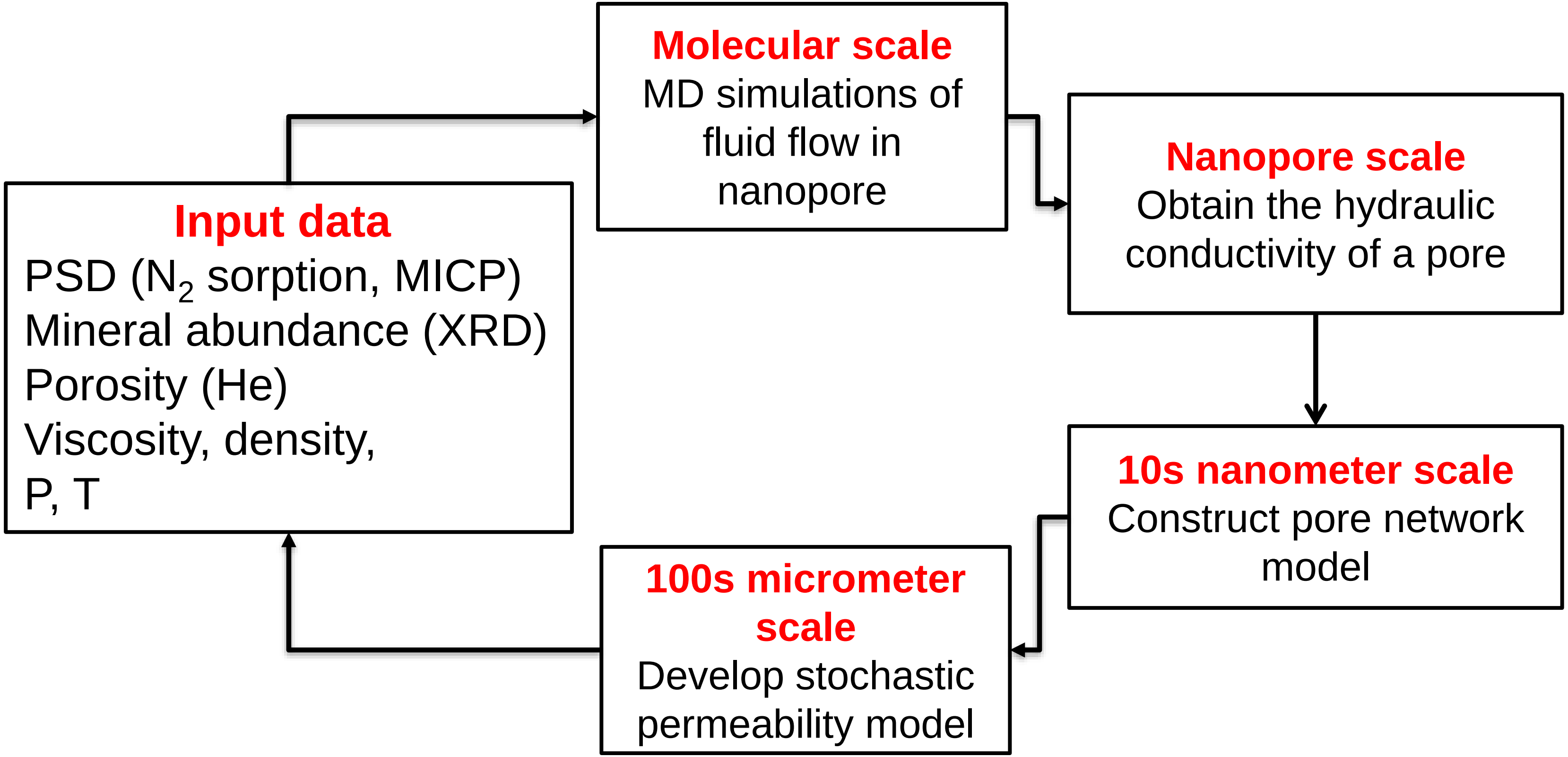


Many data at different confining stress was collected and used in model validation.



We have developed the technology of multiscale research and have tested our approach for samples from different basins such as Eagle Ford.

Framework


Molecular scale
MD simulations of fluid flow in nanopore
Nanopore scale
Obtain the hydraulic conductivity of a pore
10s nanometer scale
Construct pore network model
100s micrometer scale
Develop stochastic permeability model
Input data
PSD (N_2 sorption, MICP)
Mineral abundance (XRD)
Porosity (He)
Viscosity, density,
P, T

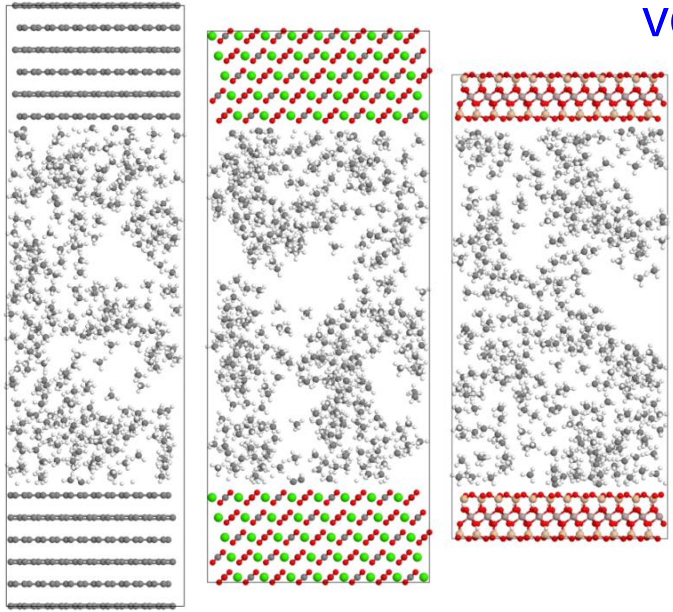
Exploring the Flow Behavior Using MD

CH_4 adsorption slip length

Solid model | Liquid model | EMD | NEMD | Flow characterization

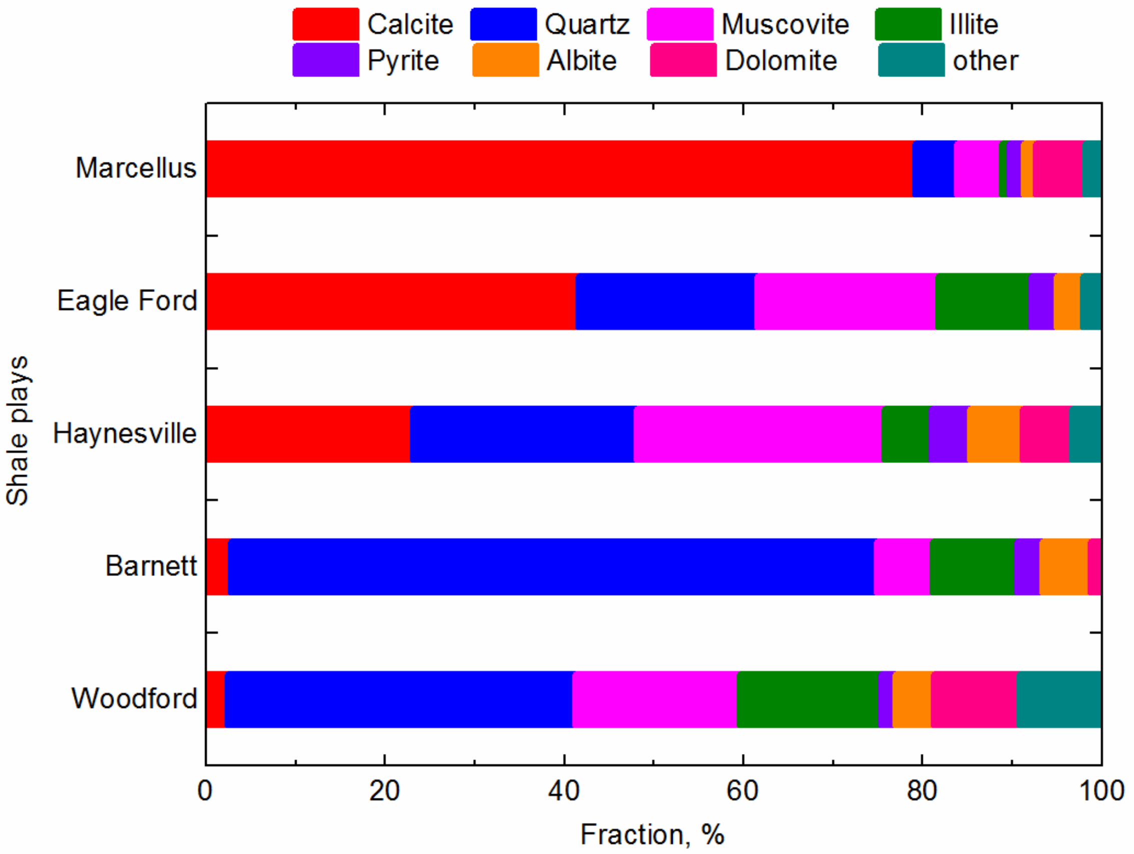
velocity profile

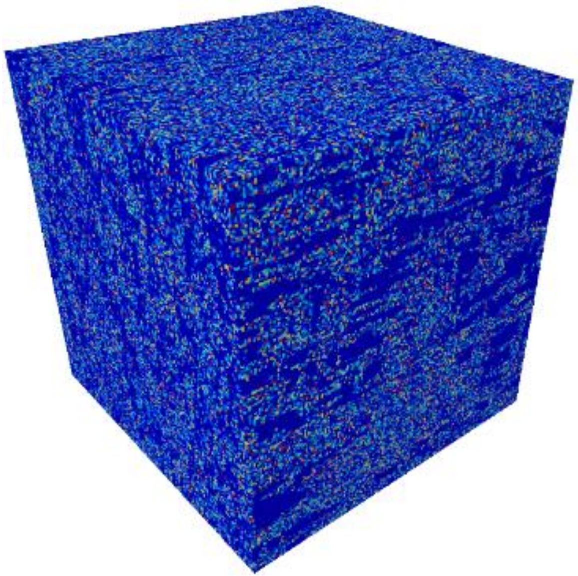
- OM
- calcite
- montmorillonite



T=386 K, P=39.5 MPa

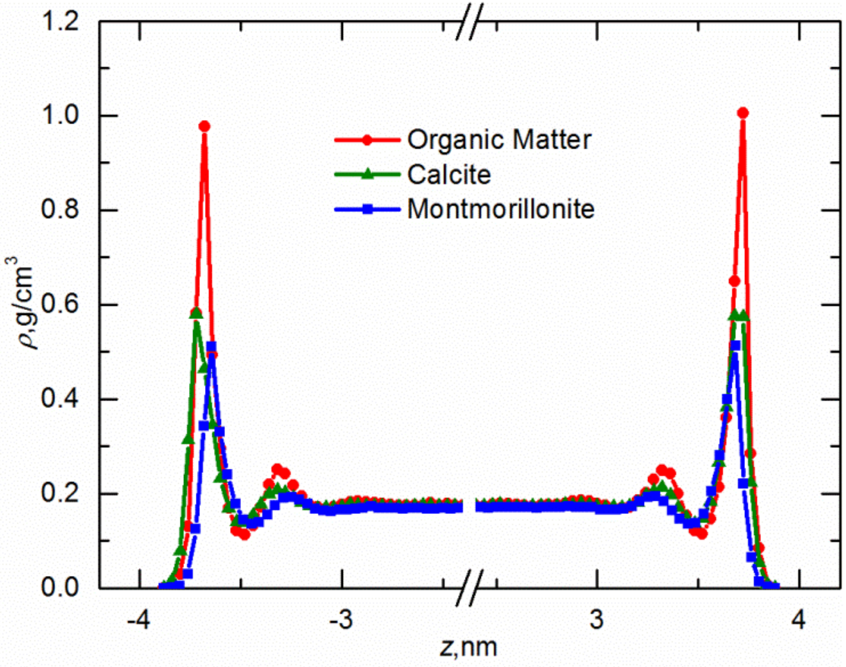
Slit aperture：3.44 nm

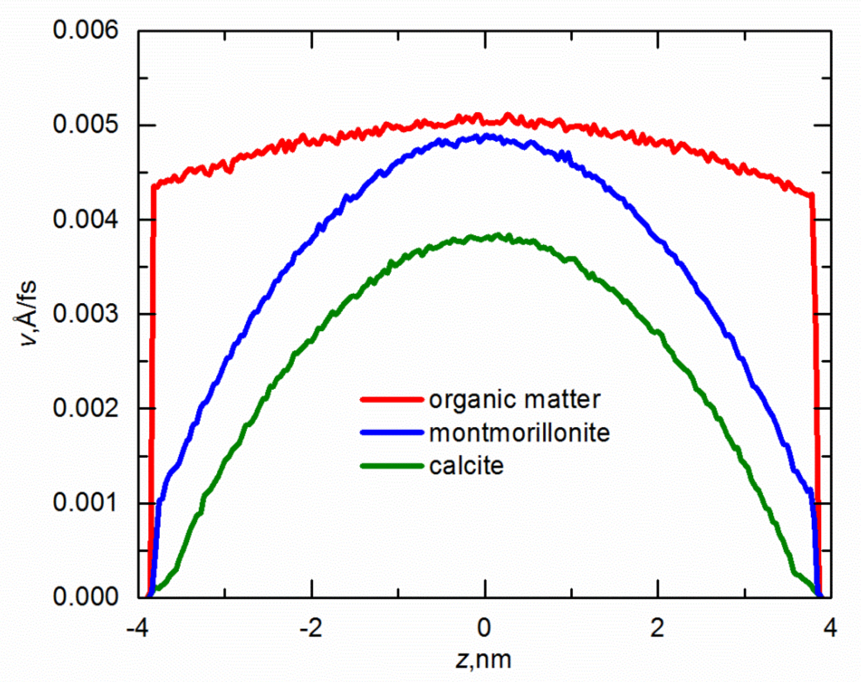




(After Clarkson et al., 2013)

Density and velocity profiles





Flow characterization

$$\begin{cases} \boxed{v = -\dfrac{\mathrm{grad}P}{2\eta_{eff}}\left(z^2 - \dfrac{w^2}{4} - wL_s\right)} \\ \boxed{Q = \dfrac{\mathrm{grad}P \cdot w^3}{12\eta_{eff}}\left(1 + \dfrac{6Ls}{w}\right)} \end{cases}$$

$v = az^2 + b$

$\eta_{eff} = -nF/(2a)$ $\quad L_s = \left(\dfrac{b}{a} - \dfrac{w^2}{4}\right)\dfrac{1}{w}$

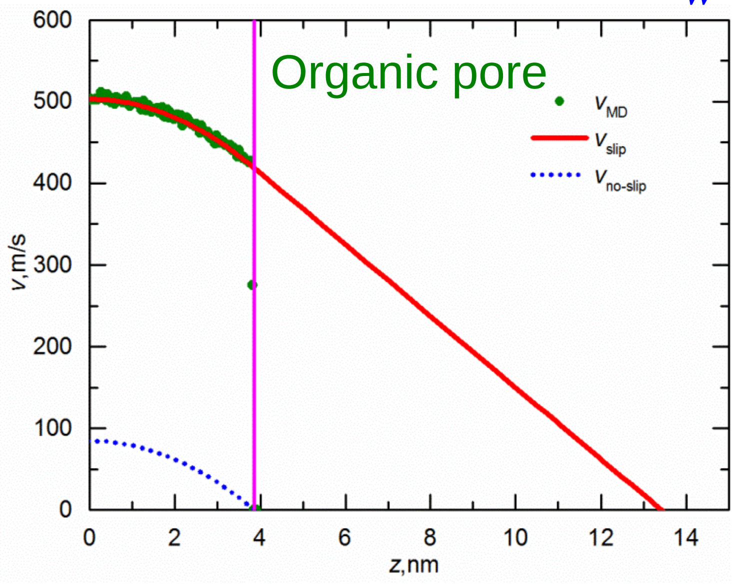
Enhancement factor $En = 1 + \dfrac{6L_s}{w}$

$\eta_{eff} = 24.3 \times 10^{-3}$ Pa.s

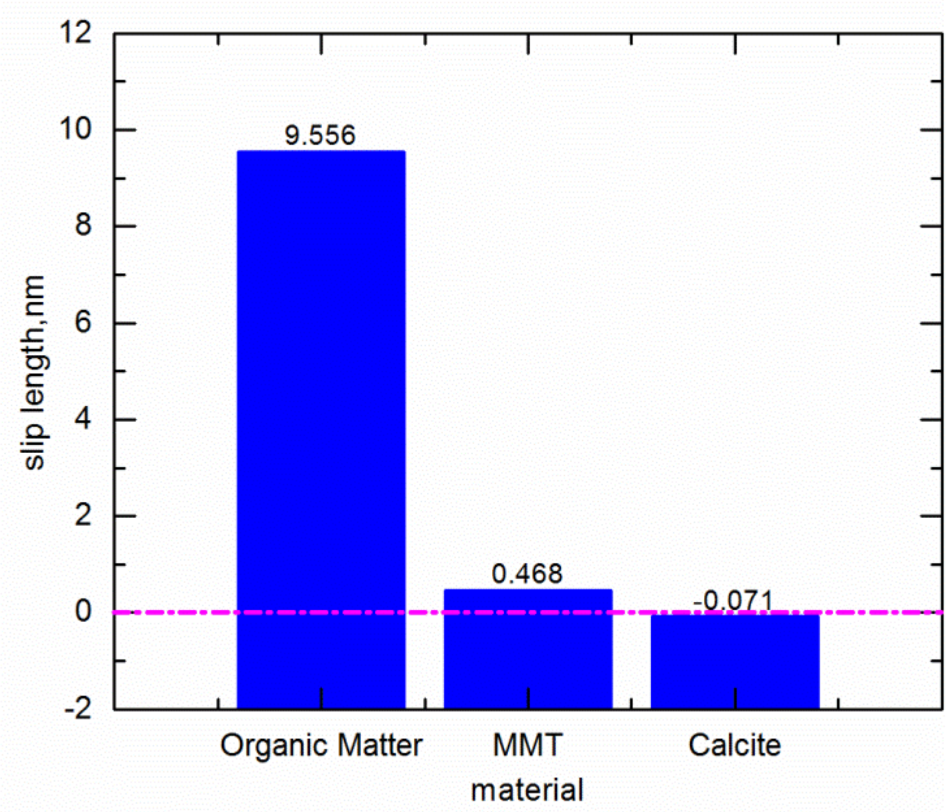
$\eta_{bulk} = 24.178 \times 10^{-3}$ Pa.s

$L_s = 9.56$ nm

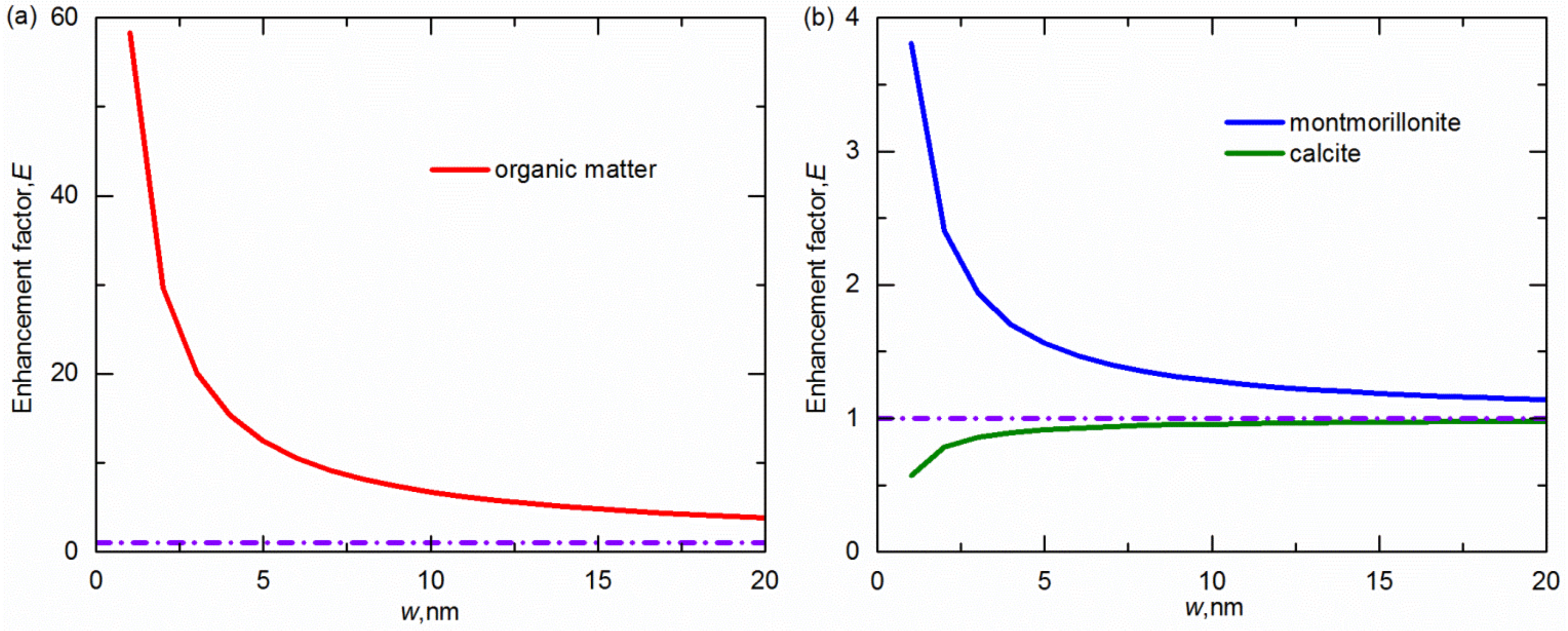
$En = 8.4$



Slip lengths in different nanoslits



Enhancement factor versus slit aperture

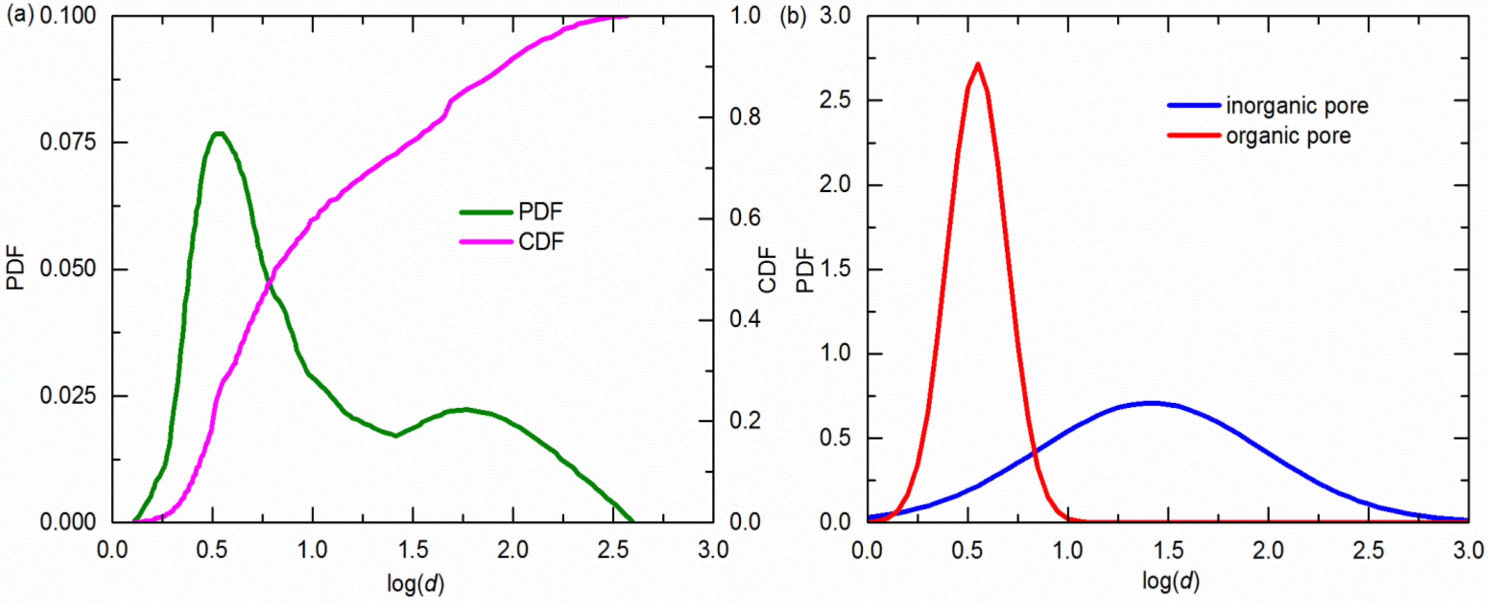


Estimating the Apparent Permeability Using PNM

$$P(R<r)=\sum_{i=1}^{N}P(F_i)P(R<r|F_i)$$

$$P(R<r|F_i)=N(\mu_i,\sigma_i)$$

$$OBF=\sum_{k=1}^{N_{\text{data}}}\left(P_{\text{data}}(R<r)-P_{\text{model}}(R<r)\right)^2$$

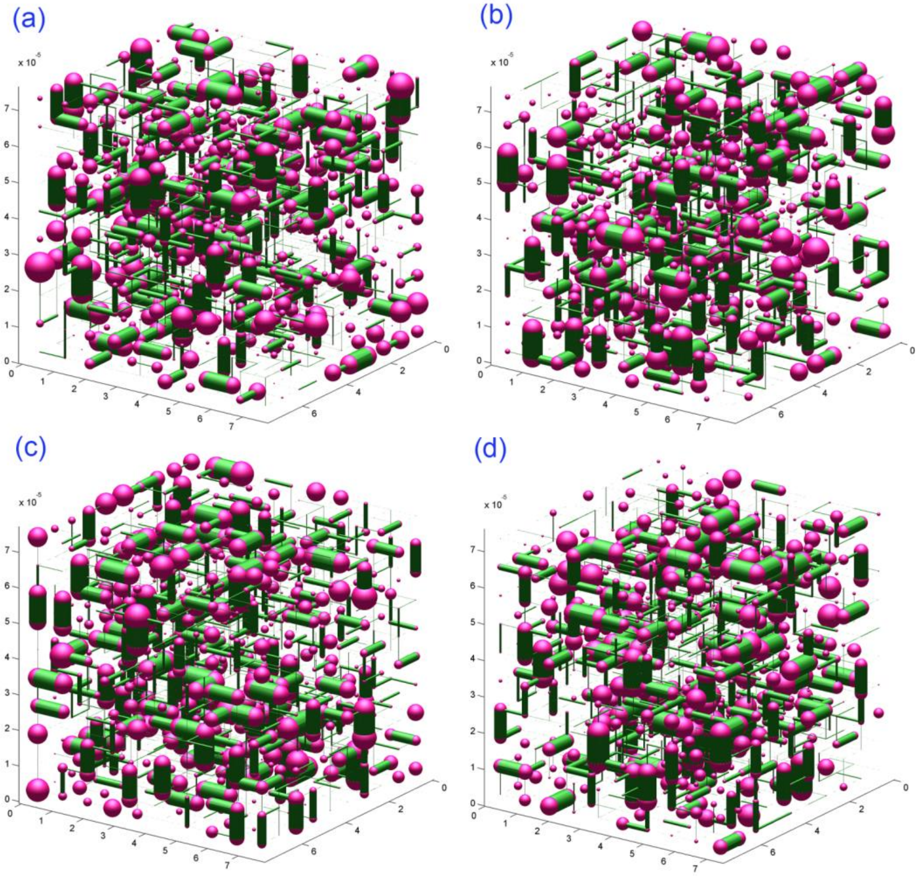


Shale pore network model

Pore type	μ	σ	fraction
OM	0.5474	0.1469	0.4094
IM	1.4124	0.5622	0.5906

Fraction of each kinds of pores

$$C_i = P\left(F_2\right)\alpha_i$$



Flow modeling in pore network model

$$Q=\frac{\nabla p\pi r^4}{8\mu}\left[1+\frac{4L_p}{r}\right]$$

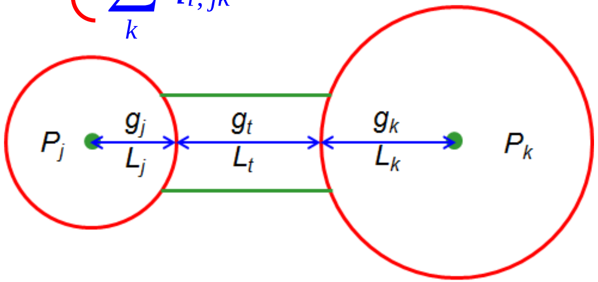
$$g=\frac{Q}{\nabla p}$$

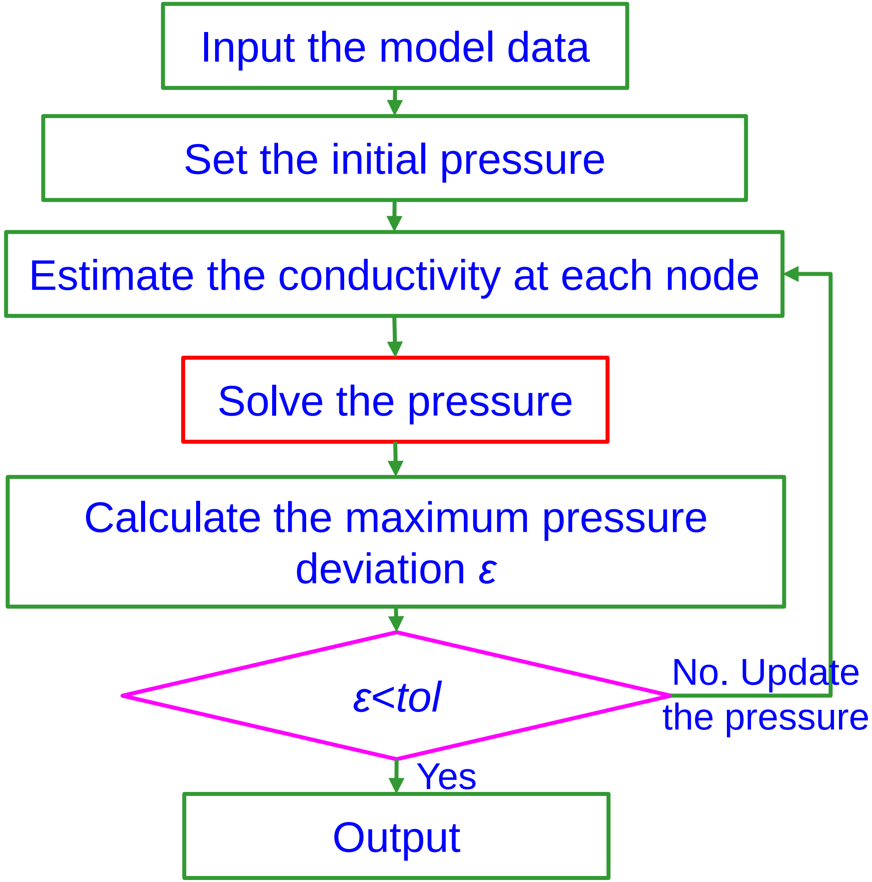
$$g=\frac{\pi r^4}{8\mu}\left[1+\frac{4L_p}{r}\right]$$

At each node

$$\begin{cases} q_{i,jk}=\dfrac{g_{i,jk}}{L_{jk}}\left(P_{i,j}-P_{i,k}\right) \\ \sum_k q_{i,jk}=0 \end{cases}$$

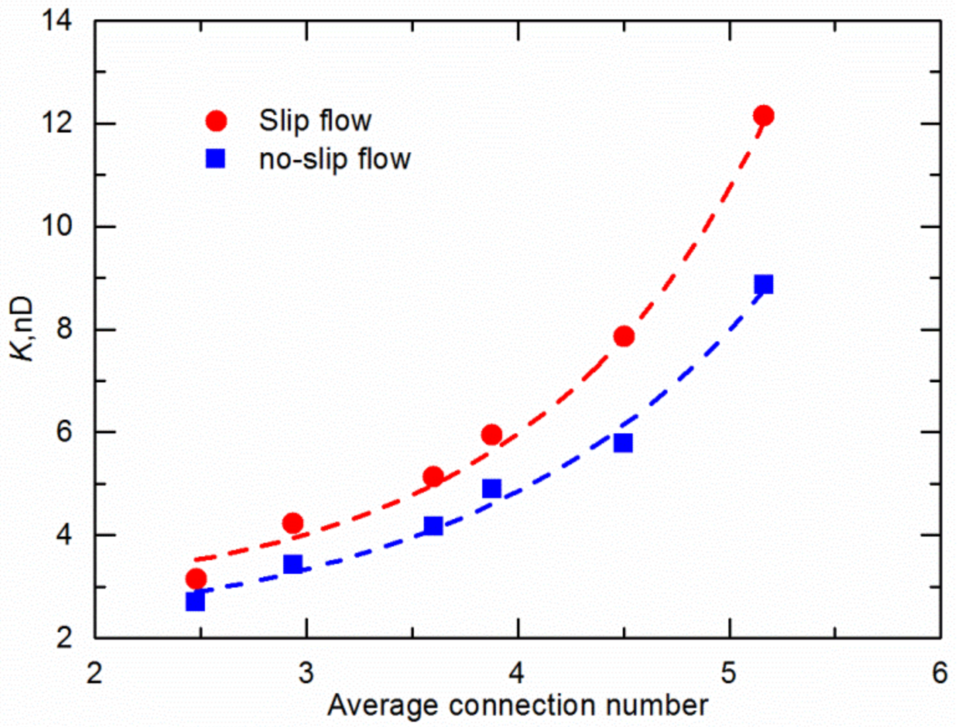
$$g_{i,jk}=\frac{L_{jk}}{\dfrac{L_j}{g_{i,j}}+\dfrac{L_t}{g_{i,t}}+\dfrac{L_k}{g_{i,k}}}$$



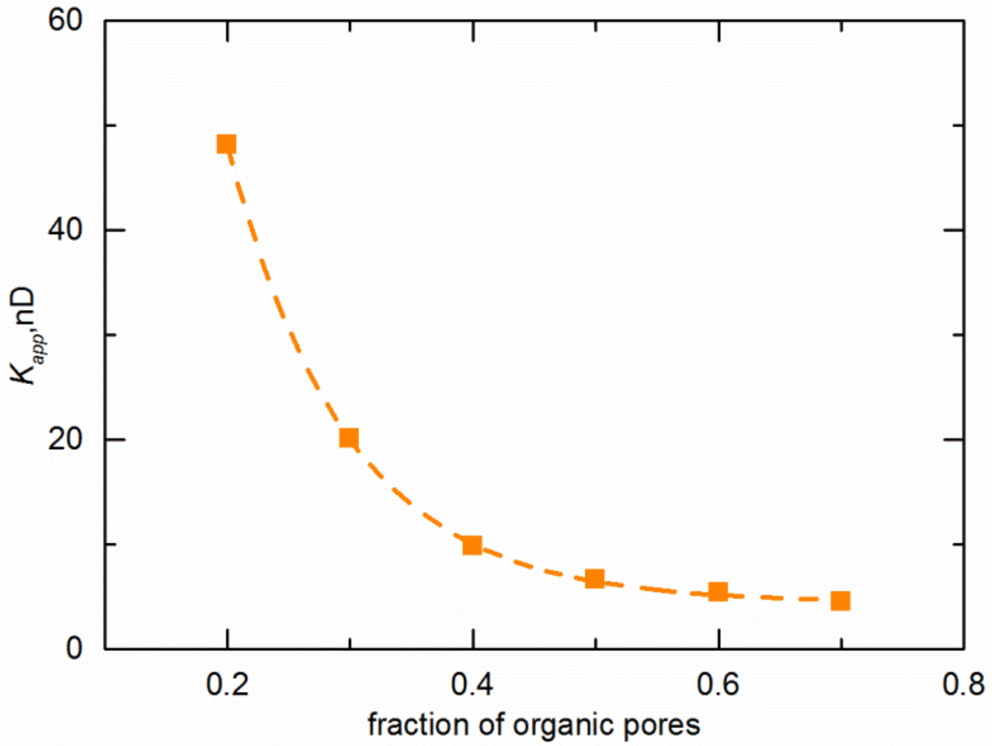


Sensitivity analysis

Property	Value
Number of pores	10×10×10
Cube size	~75 µm
Pore-throat ratio	1-3
Fraction of each pore type	40.94% OM, 24.56% calcite, and 34.50% MMT
Average coordination number	4.5
Average pressure	39.5 MPa
Temperature	386 K
Porosity	9.18%±0.34%
Permeability	7.86±1.23 nD



Apparent permeability versus fraction of organic pores



Size and shape of different mineral types in Eagle Ford

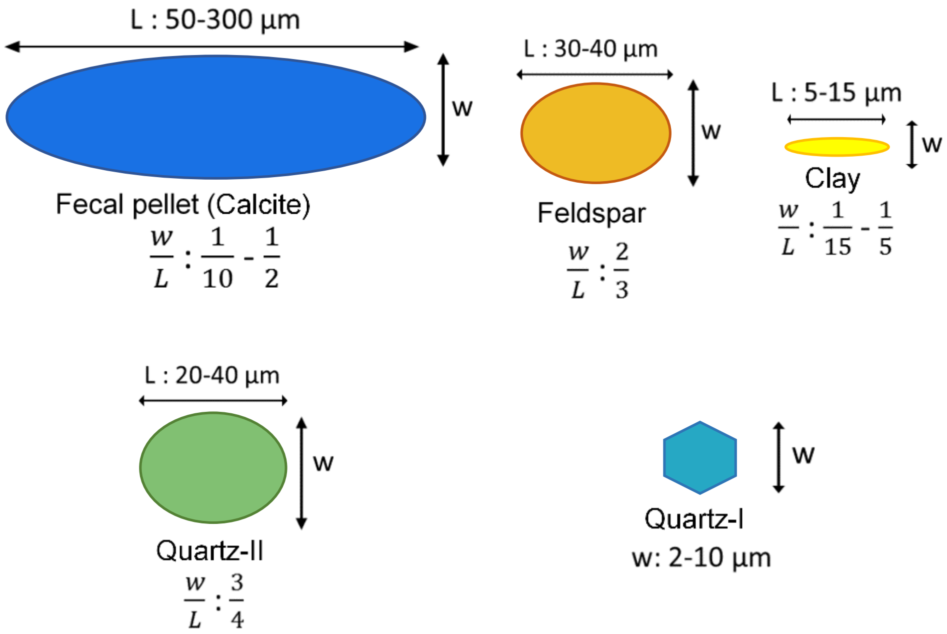
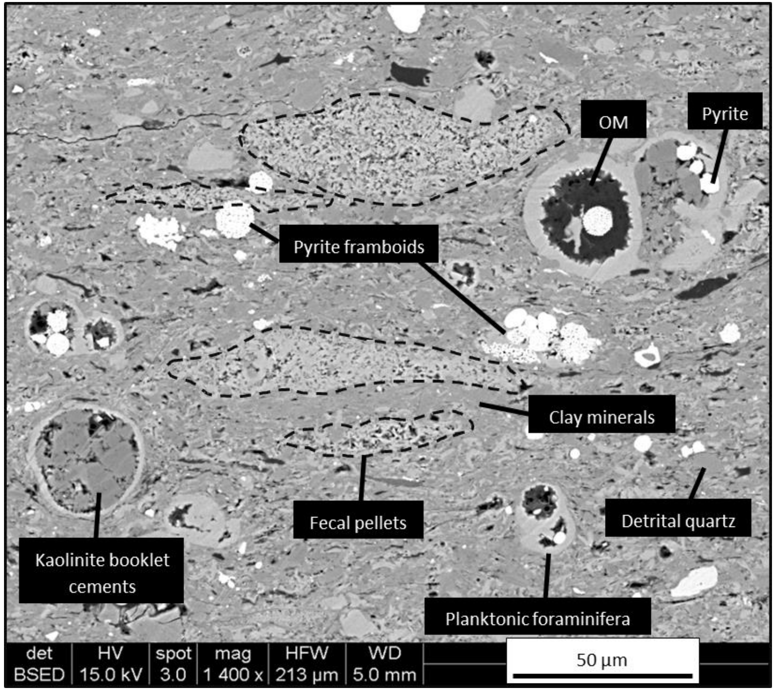
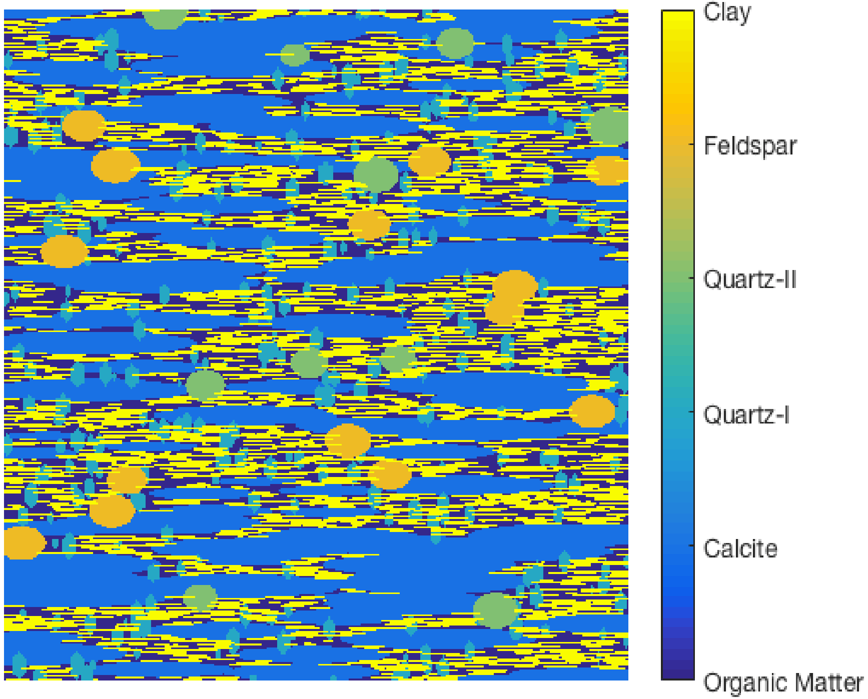


Fig. 1 Illustration of size and shape of different minerals in the studied Eagle Ford samples

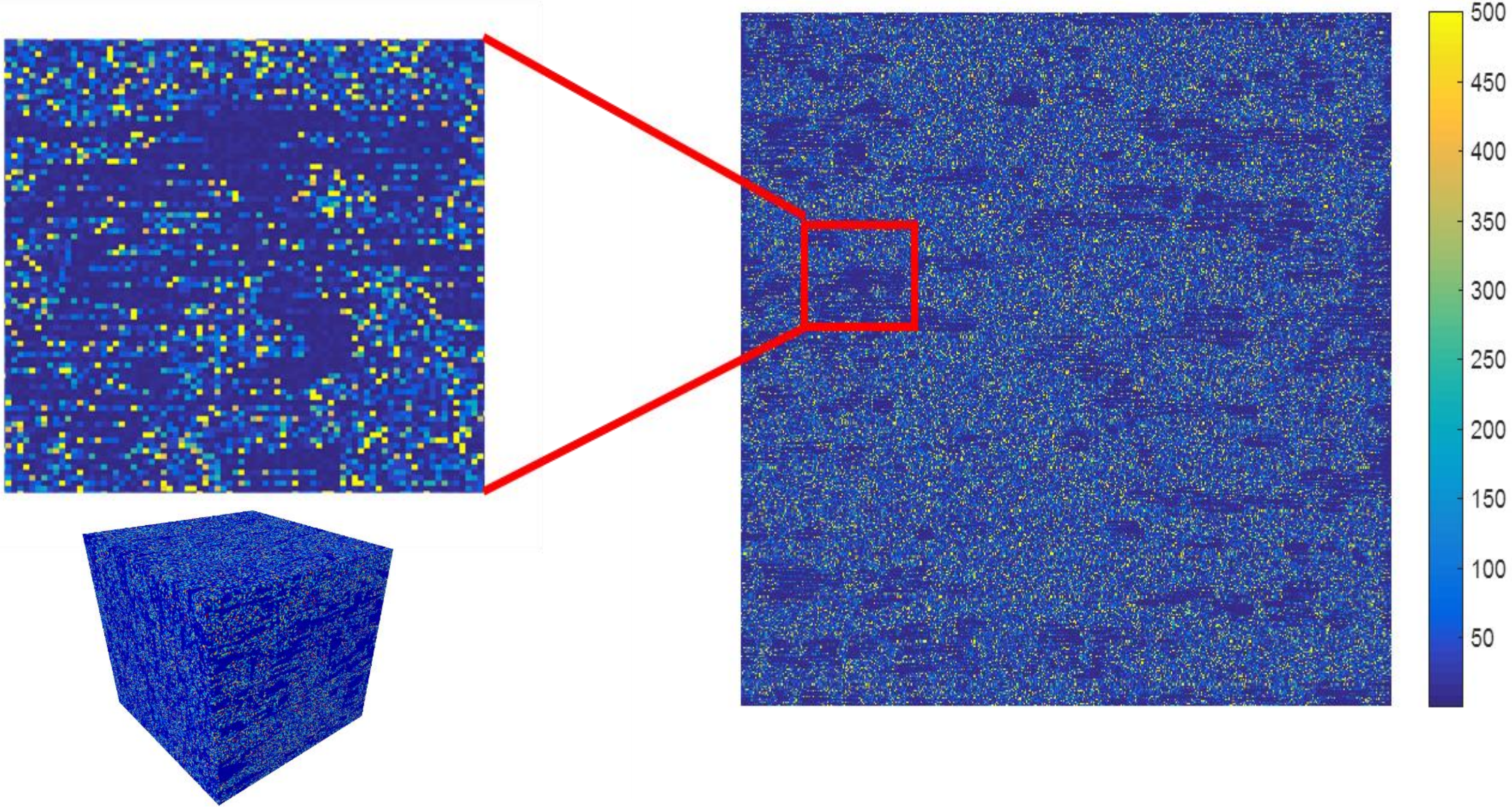
Problem Statement



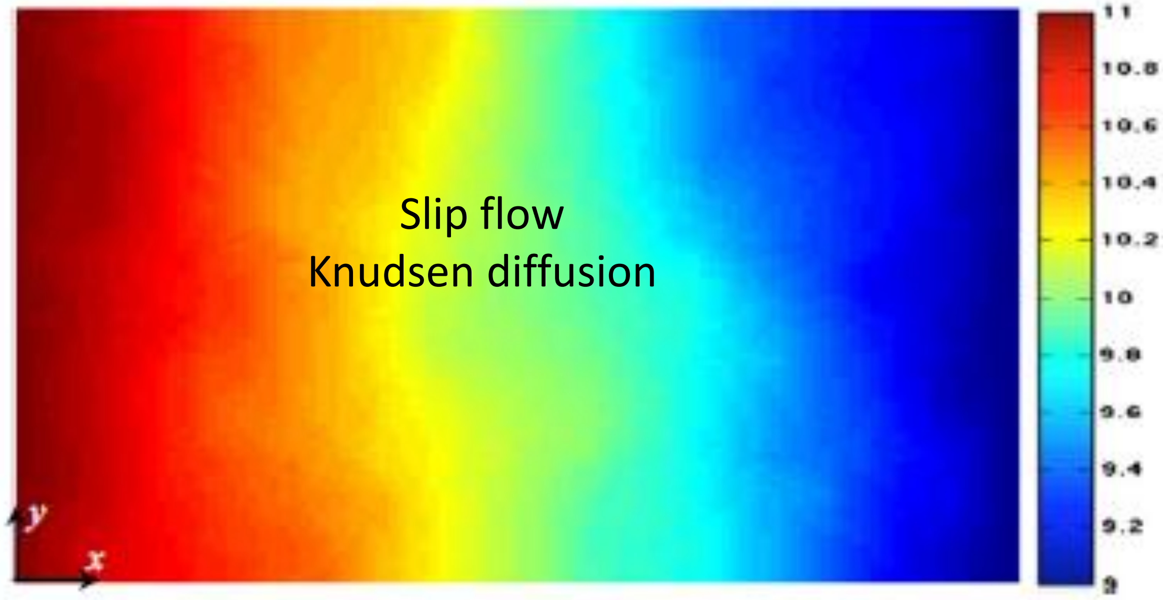


Naraghi et al., 2018

An example of a realization



Pressure field

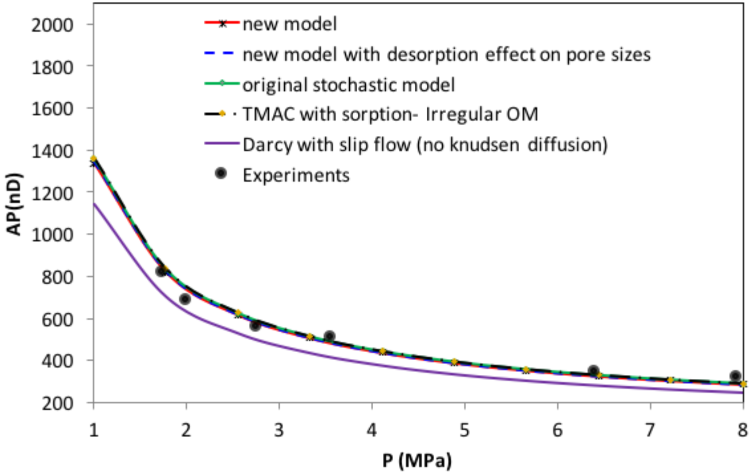


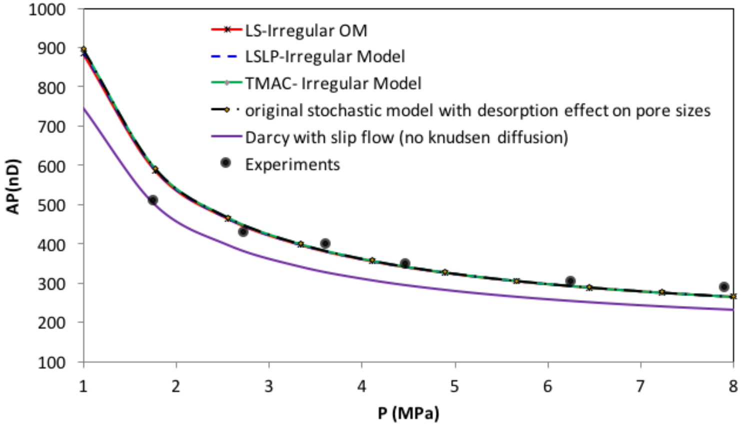
Validation→ In-house experiments

Experiment	Condition	Sample Size	Data courtesy	Results
Nitrogen sorption	Clean sample	Powder	Dr. T. Zhang (UT-Austin)	Pore size distribution
Helium porosity measurement	As received sample		Dr. A. R. Bhandari (UT-Austin)	Porosity
Pulse Decay	As received sample	Core plug	Dr. A. R. Bhandari (UT-Austin)	Permeability
In-house Setup	Confined Stress (27.6 MPa) with Methane	Powder	Dr. T. Zhang (UT-Austin)	Langmuir isotherm

	Permeability (nD)
Experiment	15
Stochastic model	27.6
Singh and Javadpour (2015)	40

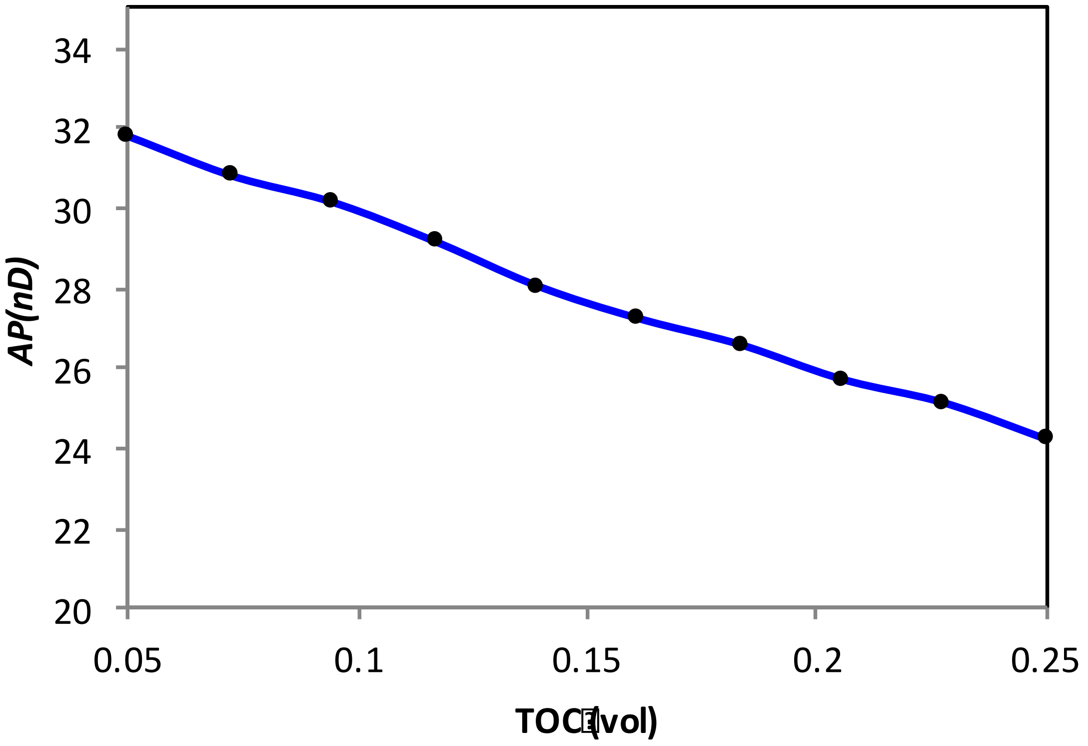
Validation → Literature Data



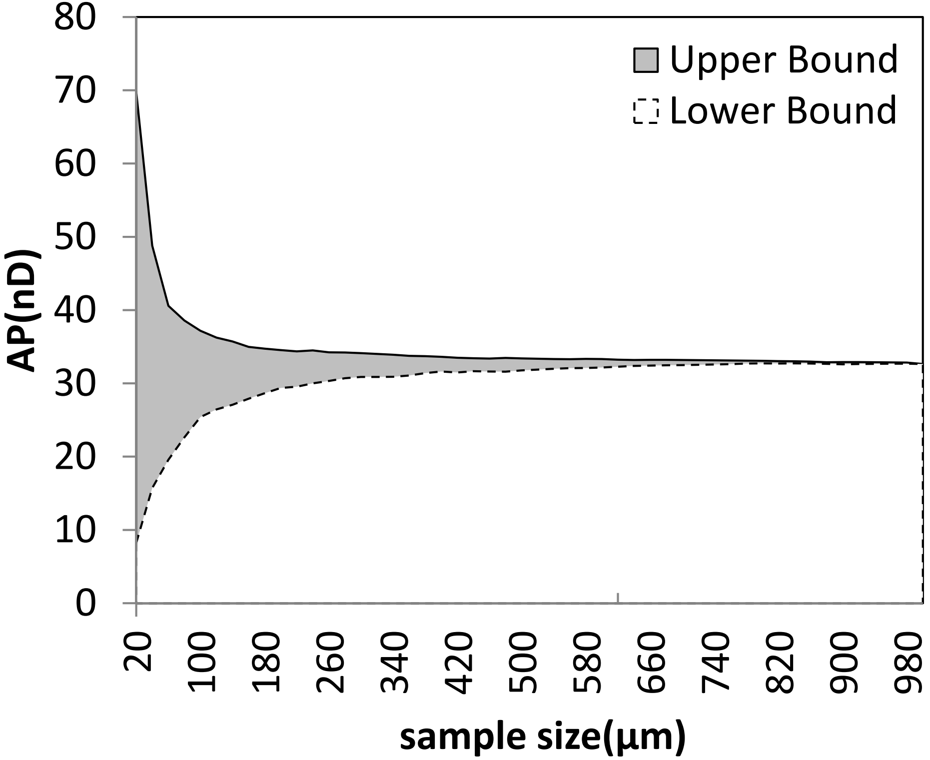


Experimental data:
Letham 2011

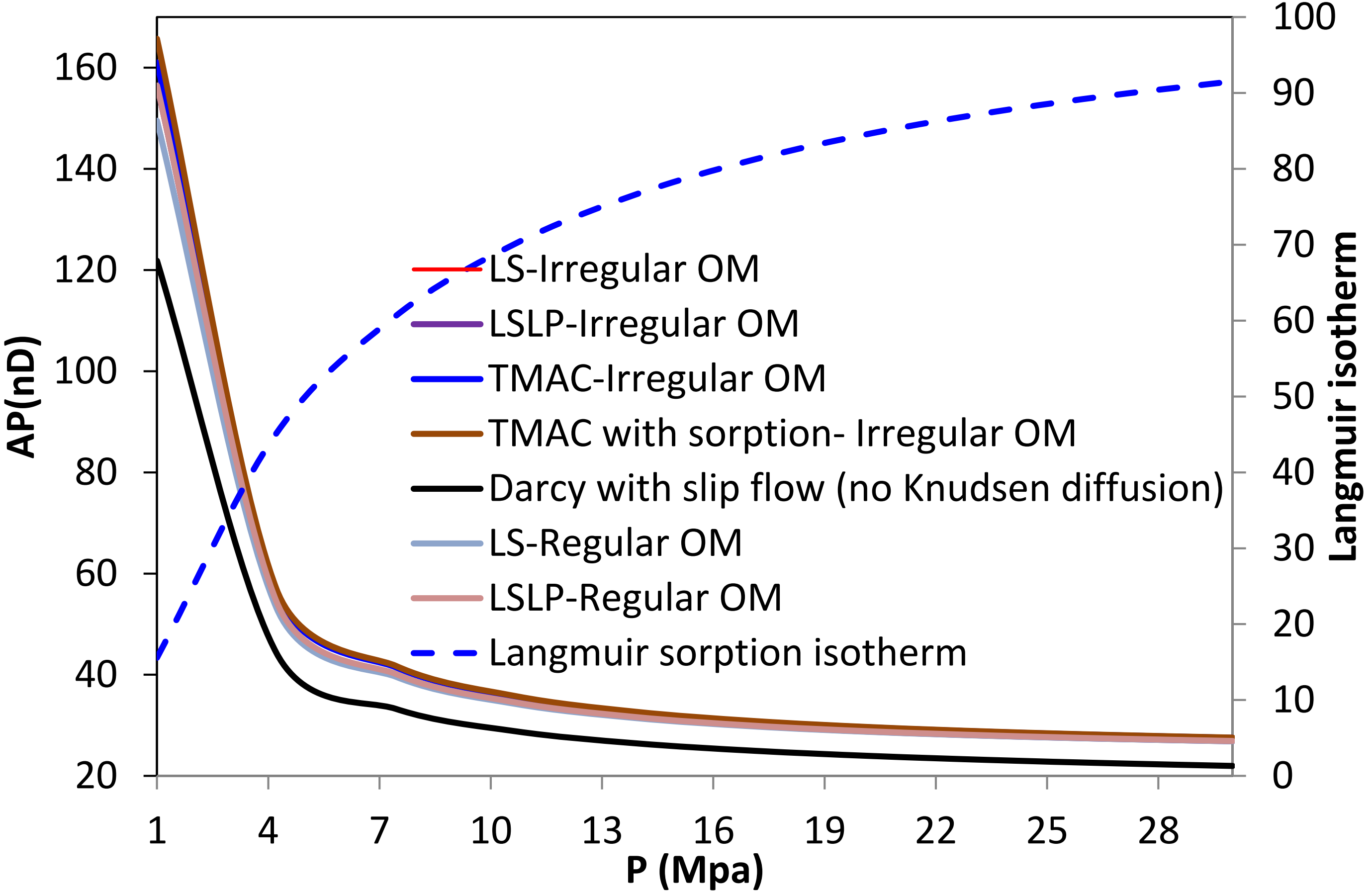
Effect of TOC



Effect of sample size



Sorption effect on permeability



Summary and Conclusion

- ❖ We present a multiscale framework to model fluid flow through mudrock and to estimate apparent permeability.
- ❖ The transport behavior of fluid in an organic nanopore is different from that within inorganic minerals.
- ❖ At high pressures, gas transport through shale nanopores can be fairly characterized by the slip-corrected Poiseuille equation.
- ❖ Connectivity of pores in organic, in inorganic and between organic and inorganic are important factors in controlling fluid flow.

Acknowledgements

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Thank You!

Comments and Questions?

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