Mechanistic Approach to Analyzing and Improving Unconventional Hydrocarbon Production

Project Number: LANL FE-406/408/409

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Los Alamos National Laboratory

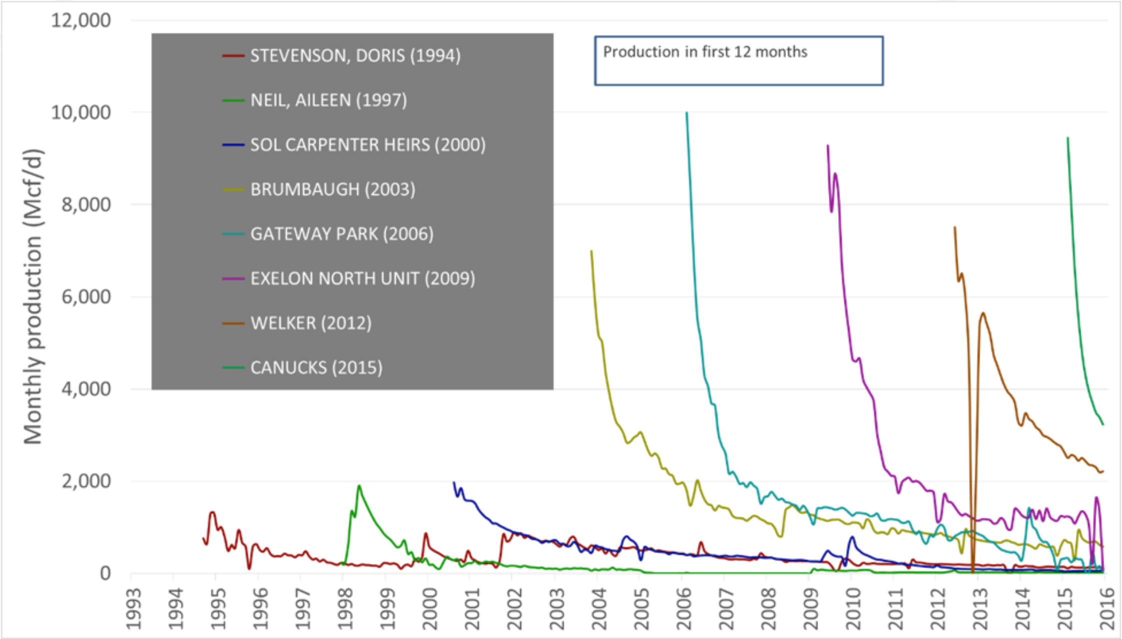
U.S. Department of Energy

National Energy Technology Laboratory

Mastering the Subsurface Through Technology, Innovation and Collaboration:
Carbon Storage and Oil and Natural Gas Technologies Review Meeting

August 16-18, 2016

Motivation & Program Benefit

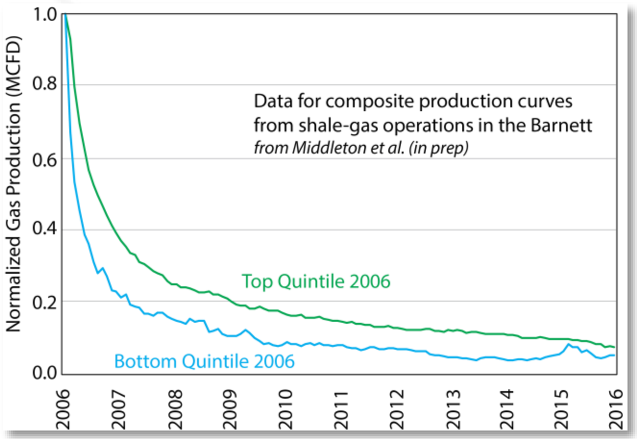


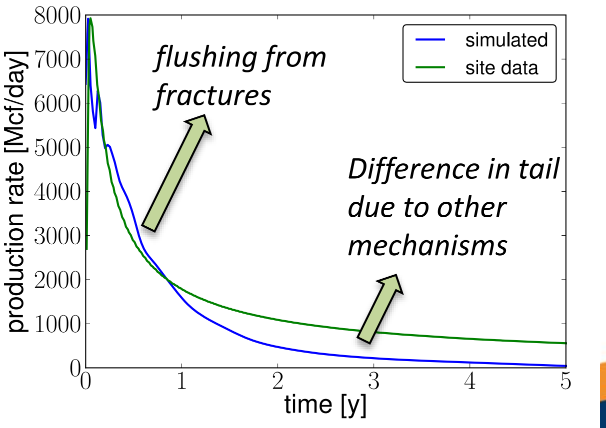
Barnett shale 'best' well production over time

- Production peaks have improved in the last two decades => fracturing technologies have improved. However, peaks have plateaued in the recent years.
- What are the key factors controlling the peak?
- Production rates from unconventional gas wells declines rapidly, but 55–65% of the production comes after the first year

Motivation & Program Benefit

- Reported production curves show that the top performing wells have improved sustained production relative to poor performing wells
- Hence, production in the tails is central to improving recovery efficiency
- Early results from LANL's discrete fracture network simulations show production in tails is not controlled solely by the fracture network
- What are the key factors controlling the tail?
- **Recovery efficiencies for shale-gas reservoirs remain low, despite being economic (motivation)**
- **Elucidating the controls on gas production (at a site) can lead to new strategies to optimize recovery efficiency (benefit)**





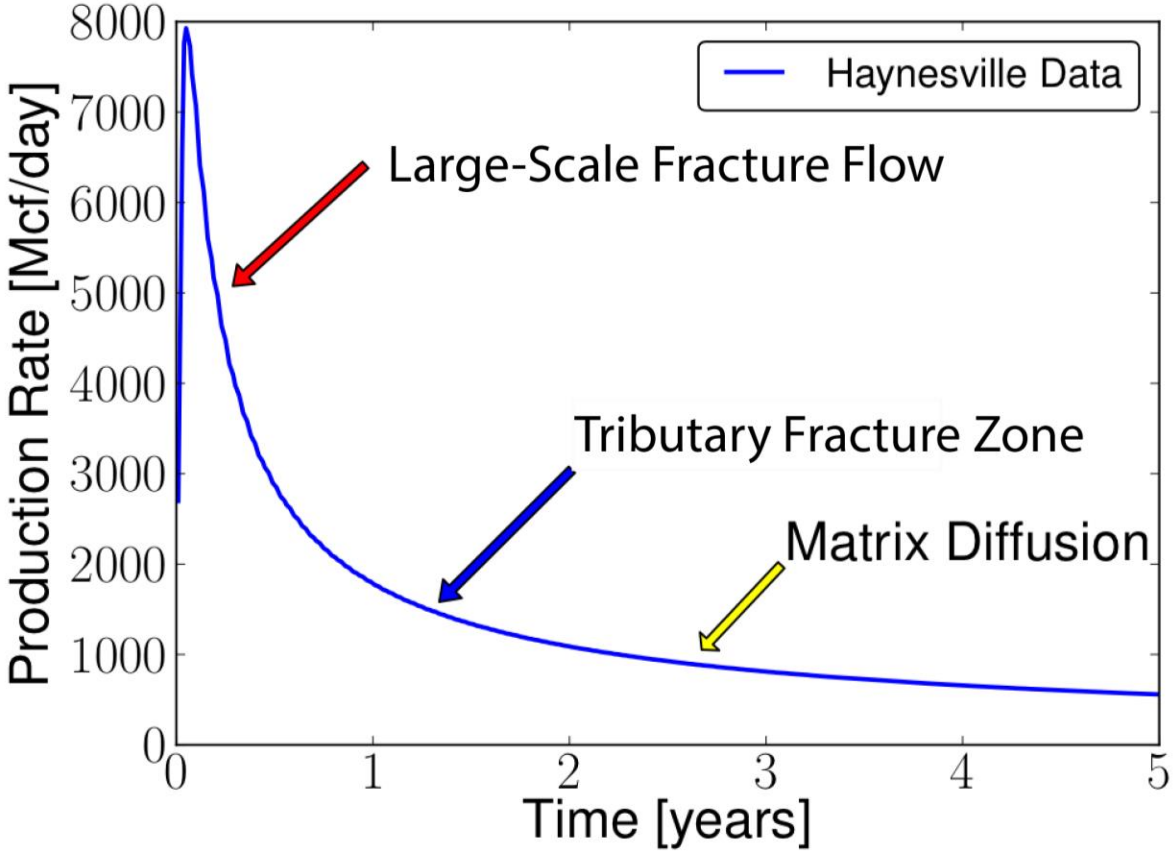
Goals and Objectives

- Develop a fundamental understanding of what controls hydrocarbon transport at different scales, using an integration of experimental and modeling methods
  - Discrete-fracture network simulations and calculation of production curves (Karra, reservoir-scale)
    - What controls gas production at reservoir scale?
    - How do pressure and residual gas evolve during production?
  - Experimental studies of fracture formation and fluid flow in fractures (Carey, core-scale)
    - How do fracture-network characteristics relate to fracture transmissivity?
    - How does fracture-network permeability couple to stress?

Goals and Objectives

- Experimental studies and pore-scale modeling of fluid behavior in shale matrix and small fractures (Xu, micro-scale)
  - How do multiphase fluids move between fractures and matrix?
  - How do pore characteristics couple to stress?

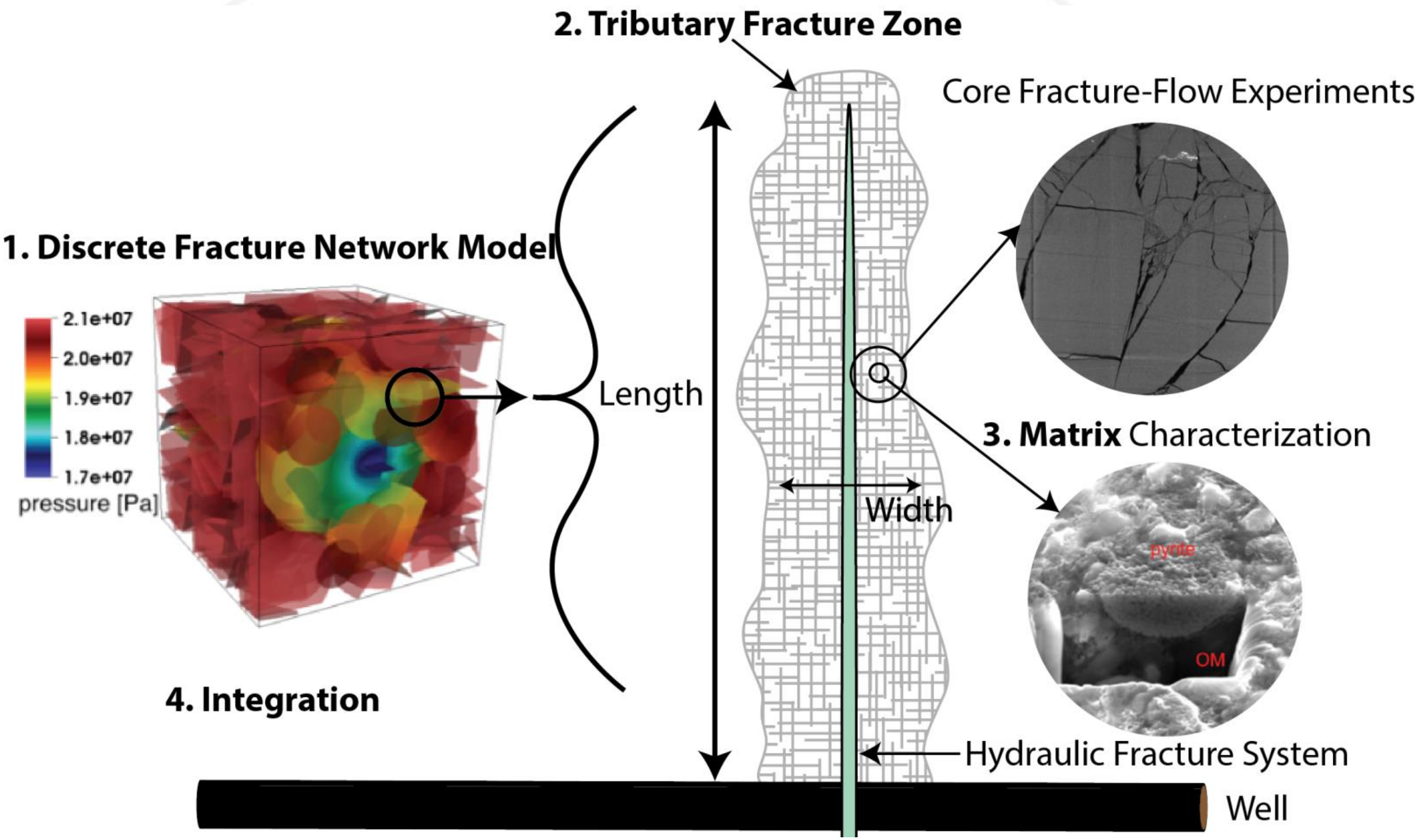
Organizing Principle: Production Curve Analysis



Viswanathan et al. ACS Books (2016)

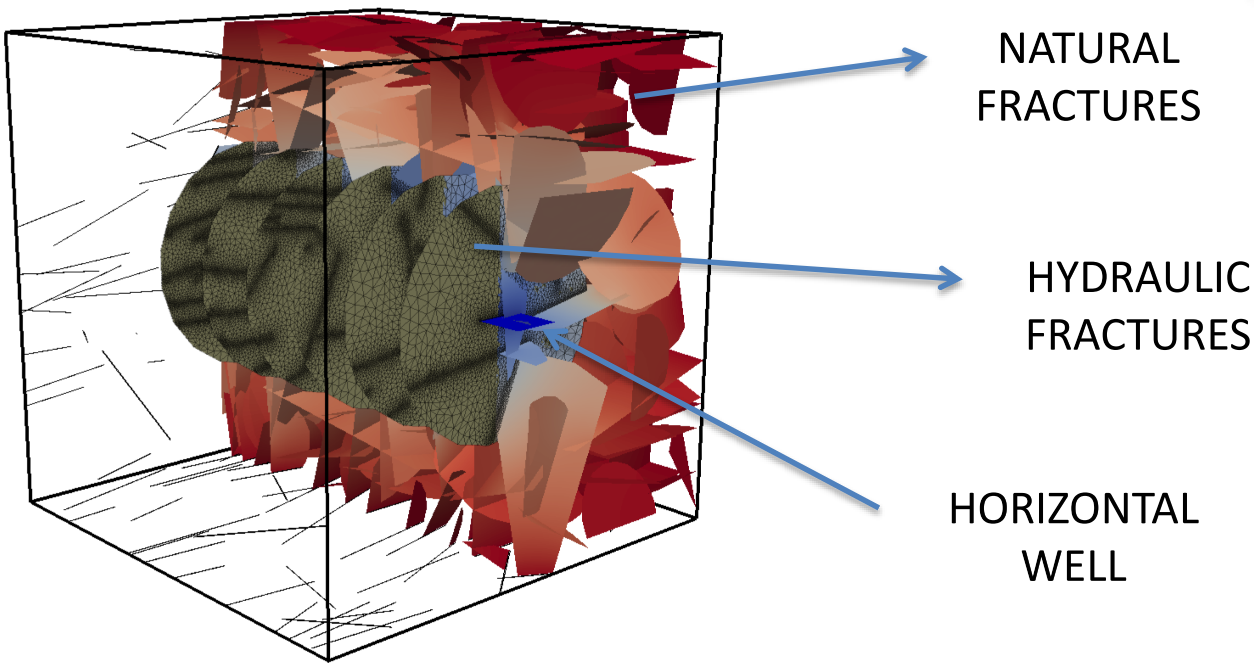
Hypothesis: Production curves reflect physical and chemical phenomena that change with time

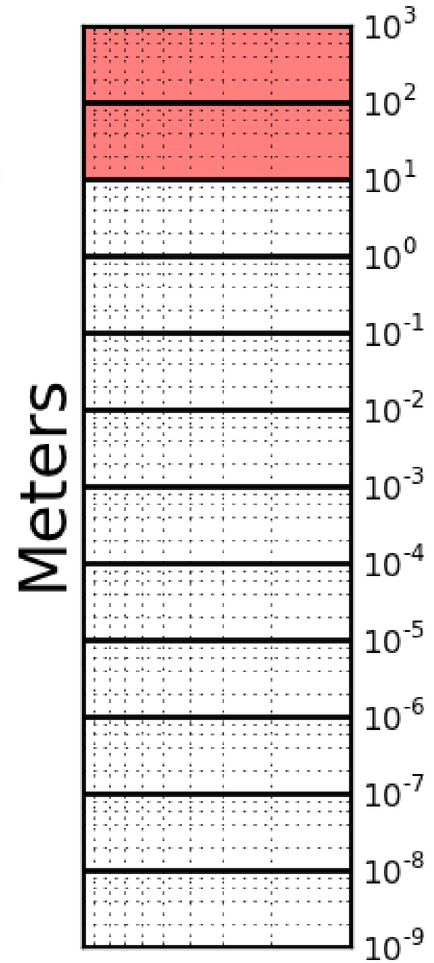
Multi-scale Features of HF



Analysis of the Production Curve

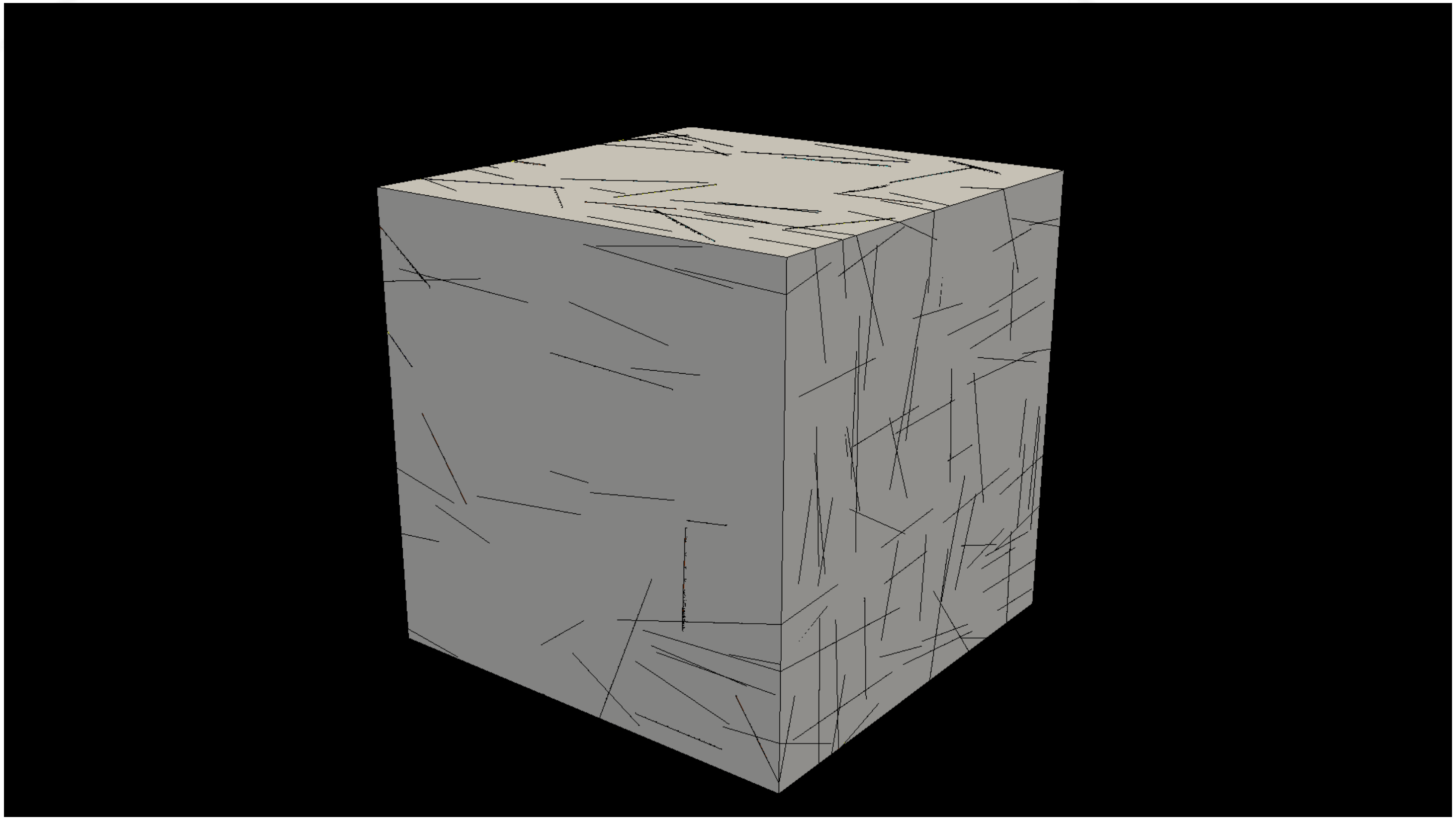
1. Discrete Fracture Network Modeling





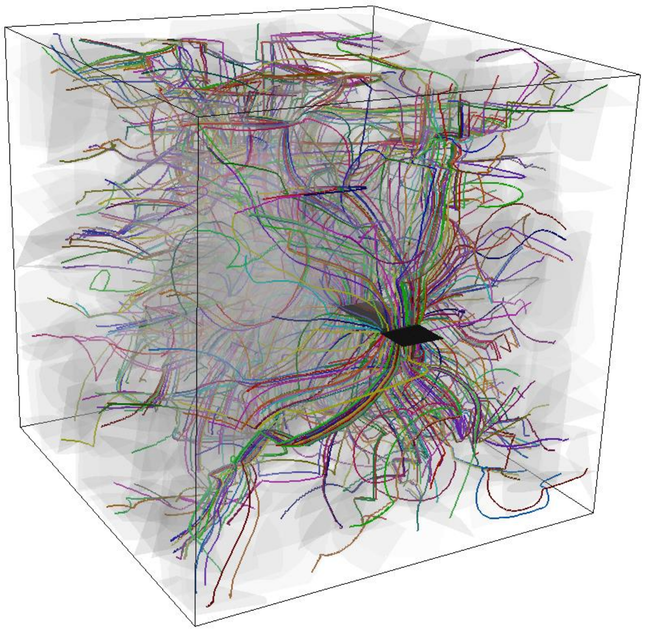
- *dfnWorks* released (*Hyman et al. Computational Geoscience 2015*)
- Mechanistic model to simulate production curve (*Karra et al. WRR* 2015)

HPC Simulation of Production

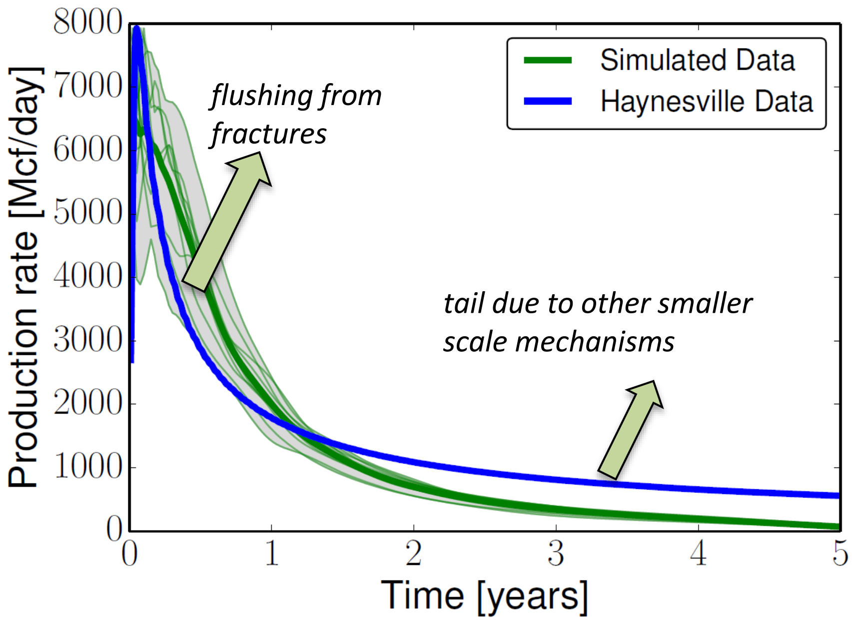


HPC Calculation of Production

Gas Particles Flowing to the Well



Production Curve

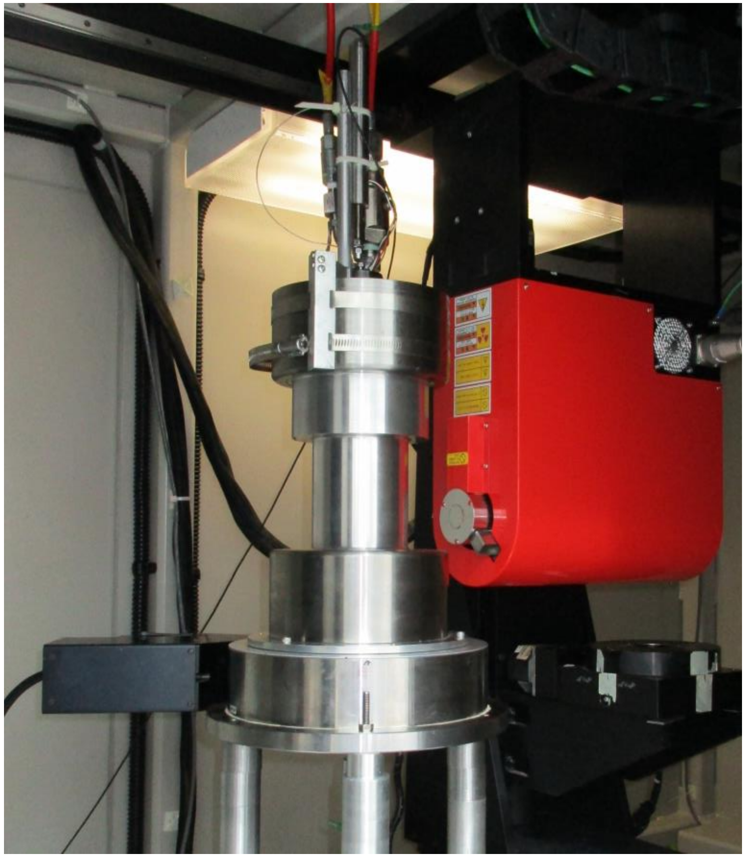


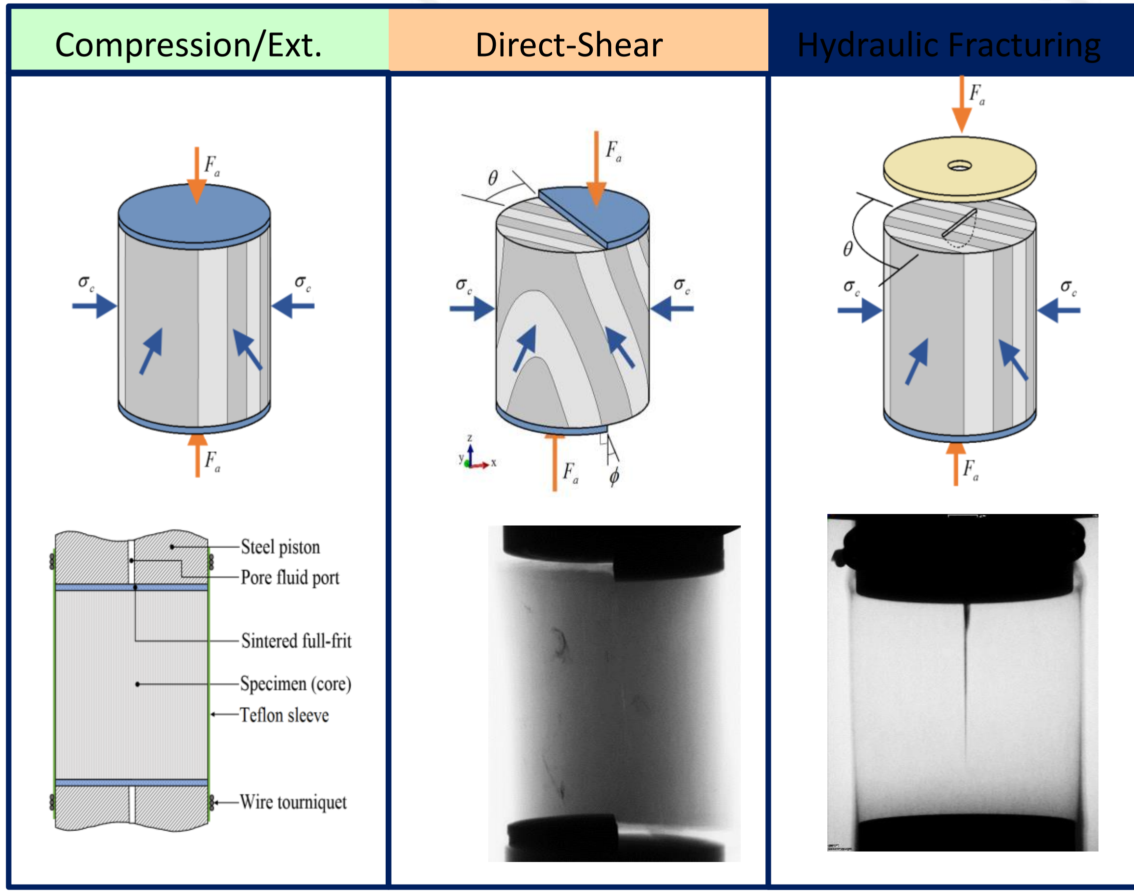
- 200m x 200m x 200m
- 383 fractures – horizontal well, 6 hydraulic fractures
- DFN statistics from upper Pottsville formation [Jin 2003]

Initial phase of production can be predicted by draining large fractures with current focus incorporating damage zone, matrix diffusion and sorption models within a UQ framework

Analysis of the Production Curve

2a. Tributary Fracture Zone

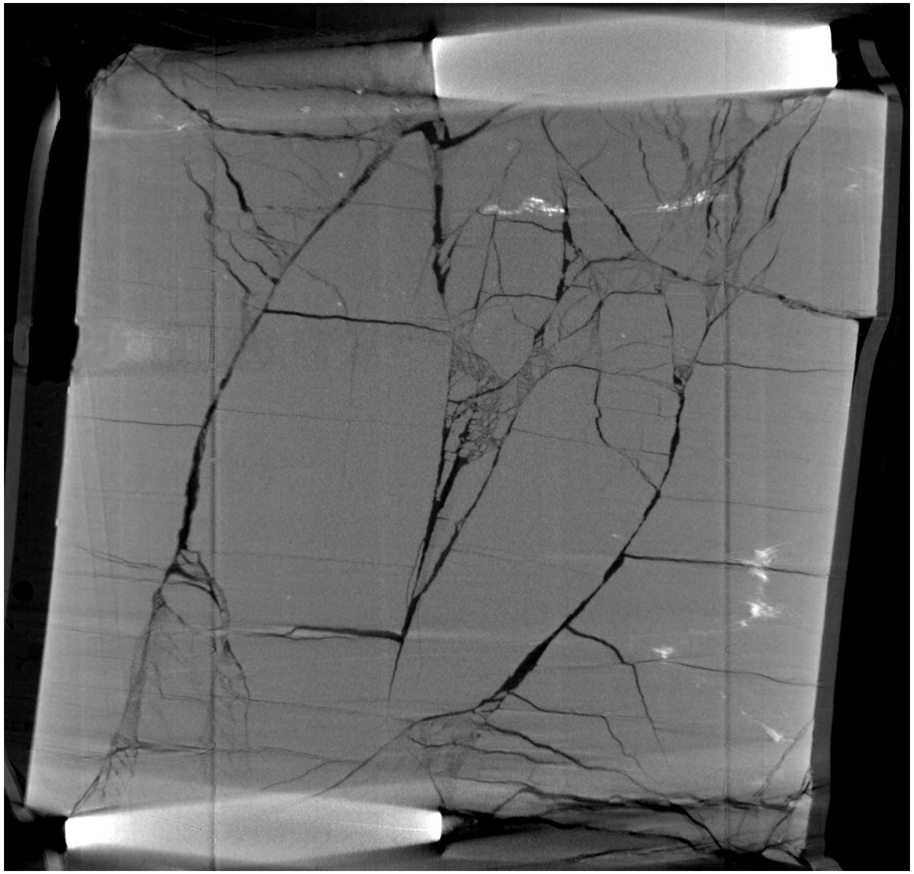


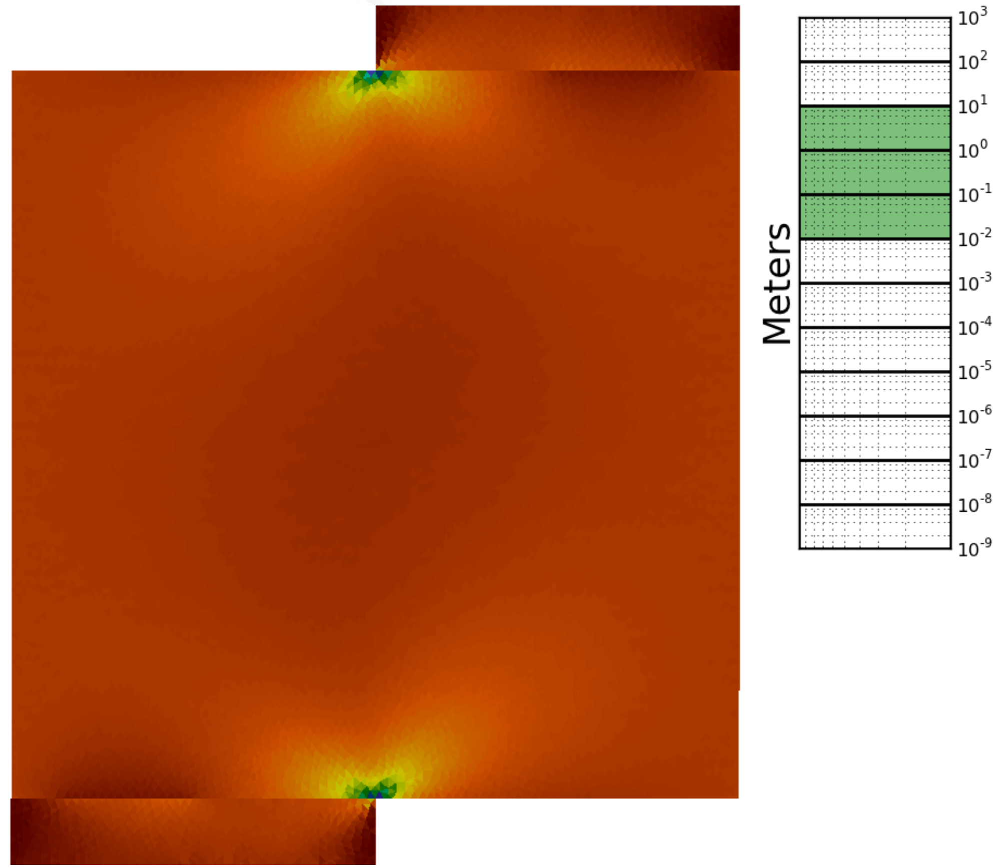


– Max Pressure: 34.5 MPa (5,000 psi)
– Max Axial Load: 500 MPa (70,000 psi)
– Max Temperature: 100 °C

Carey et al., J. Unconv. O&G Res., 2015; Frash et al. (in press) JGR; Frash et al. (submitted) Rock Mech. Rock Eng.

In Situ Tomography and Triaxial Coreflood Experiments

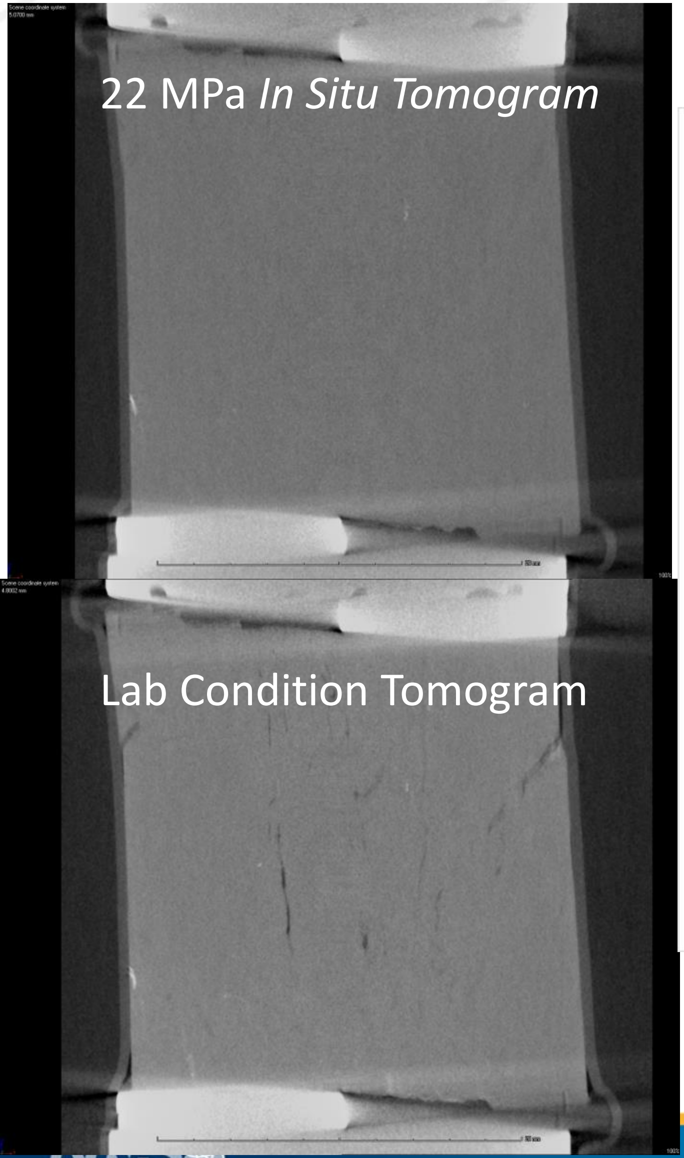


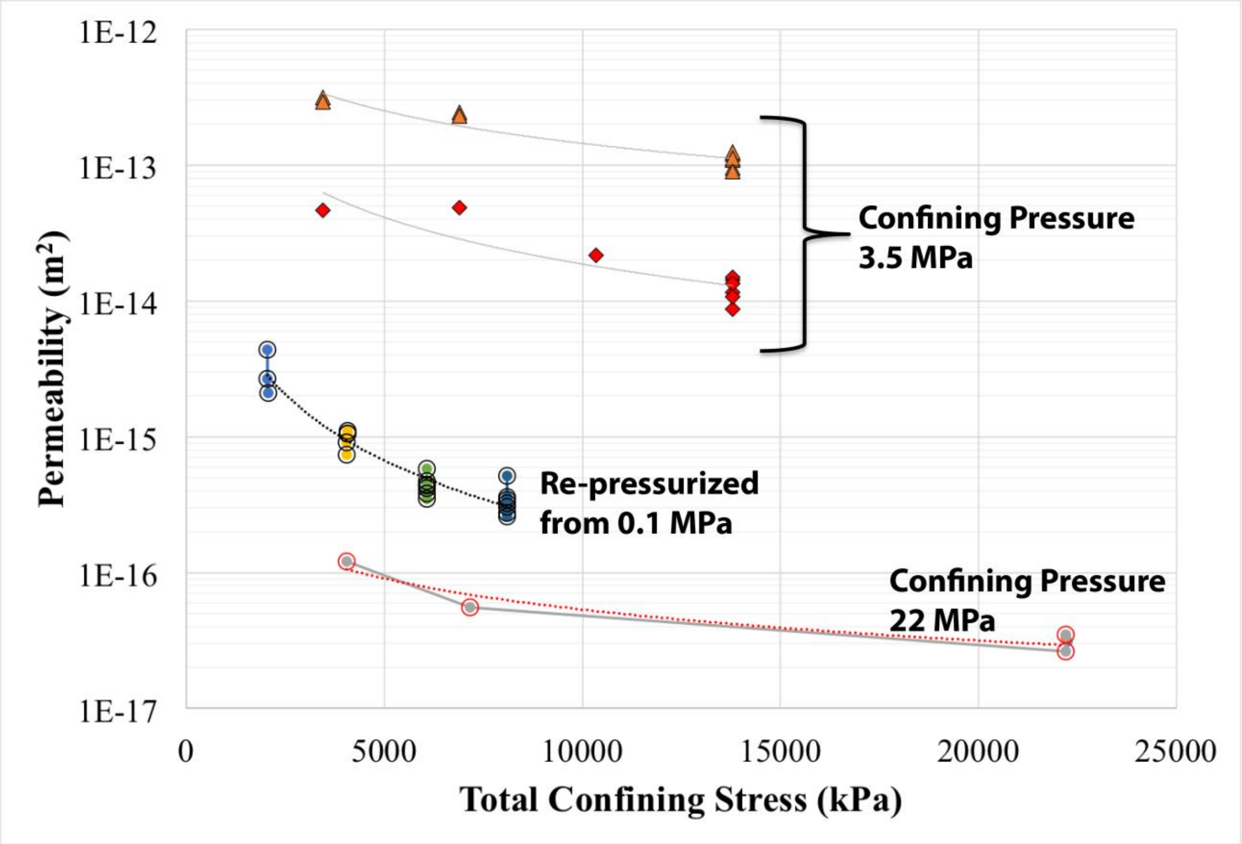


- Maximum 30 mD permeability not achieved until 8% strain!
- Good comparison with 2-D FDEM model

Carey et al. (2015) J. Unconv. O&G Res.; Lei et al. (2015) Eng. Comp.

Direct Shear: Effect of Pressure



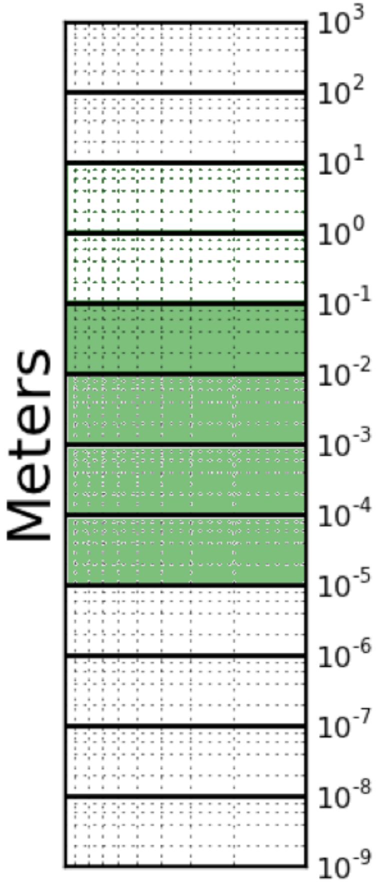


Utica shale from Chesapeake

Frash et al. (in press) JGR

Analysis of the Production Curve

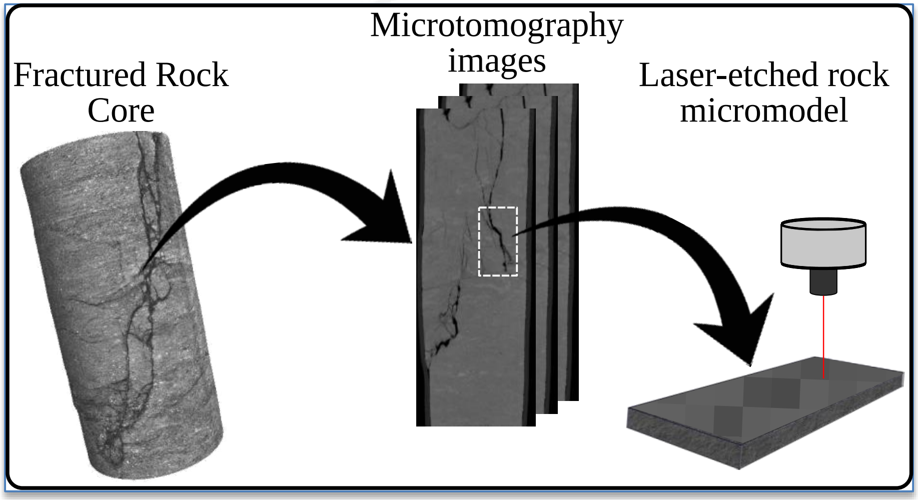
2b. Multiphase Flow in Fractures



High-pressure/Temperature Microfluidics System with Geomaterials

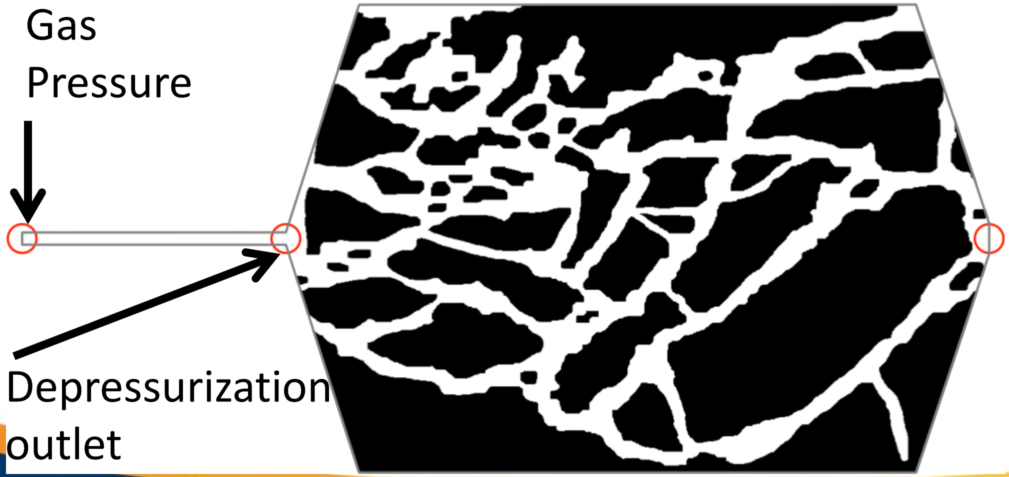
Real-time observation/quantification of fluid flow, transport and reaction

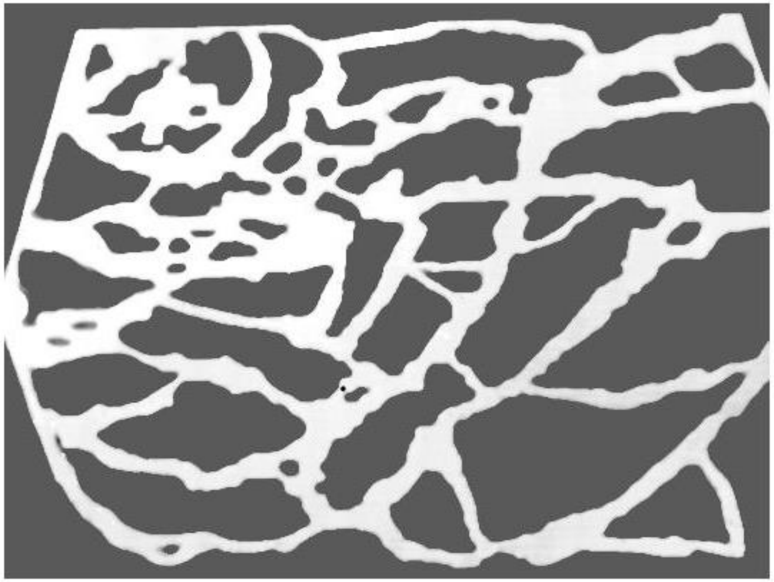
Oil Displacement Experiments



Porter et al. (2015) Lab Chip;
Jiménez-Martínez et al. (2016) GRL

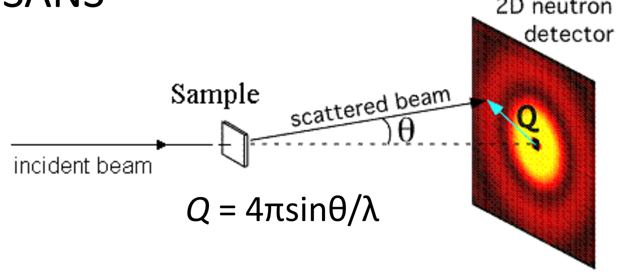
1. Fracture network saturated with oil.
2. System pressurized and allowed to soak for a specified time.
3. System depressurized at a specified rate.
4. Quantify amount of oil produced



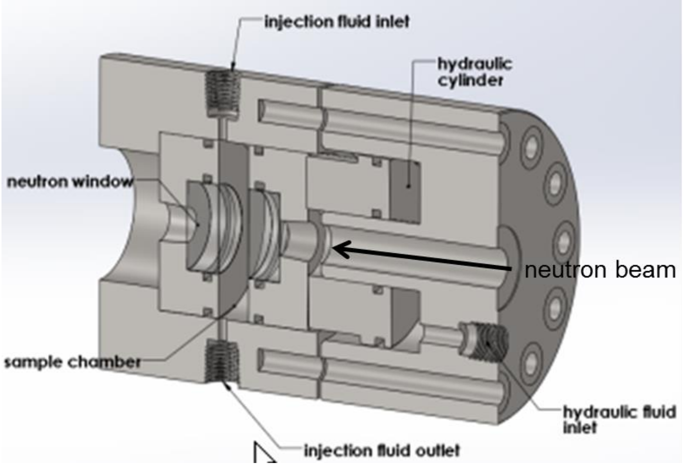


Analysis of the Production Curve
3a. Fluid Behavior in the Shale Matrix

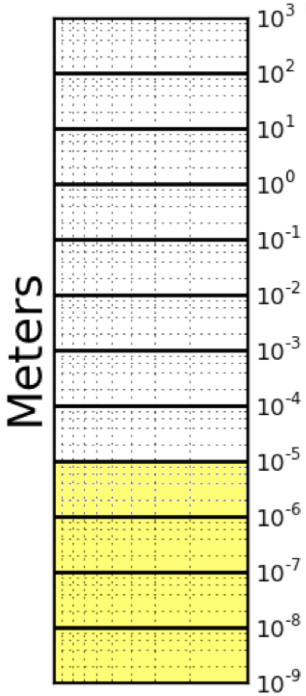
Ultra- and Small-Angle Neutron Scattering: USANS and SANS



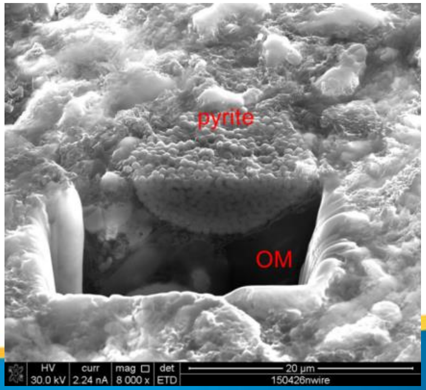
- Characterize pores (open and filled) ranging from 1 nm to 20 μm
- Use with controlled environment cells
- Sensitive to hydrogen in water and hydrocarbon



Custom-designed oedeometer for study of pore structure and saturation evolution during compaction due to uniaxial loading (60 MPa, 8700 psi)



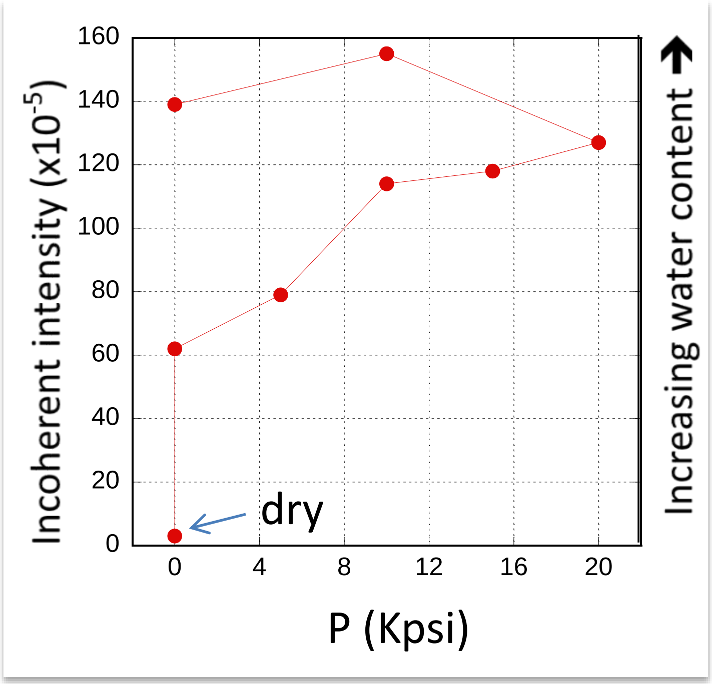
Hydrostatic cell for study of pore and saturation evolution under uniform pressure conditions (300 MPa, 43,500 psi; 200 °C)



Focused Ion Beam—Scanning and Transmission Electron Microscopy: FIB-SEM/TEM

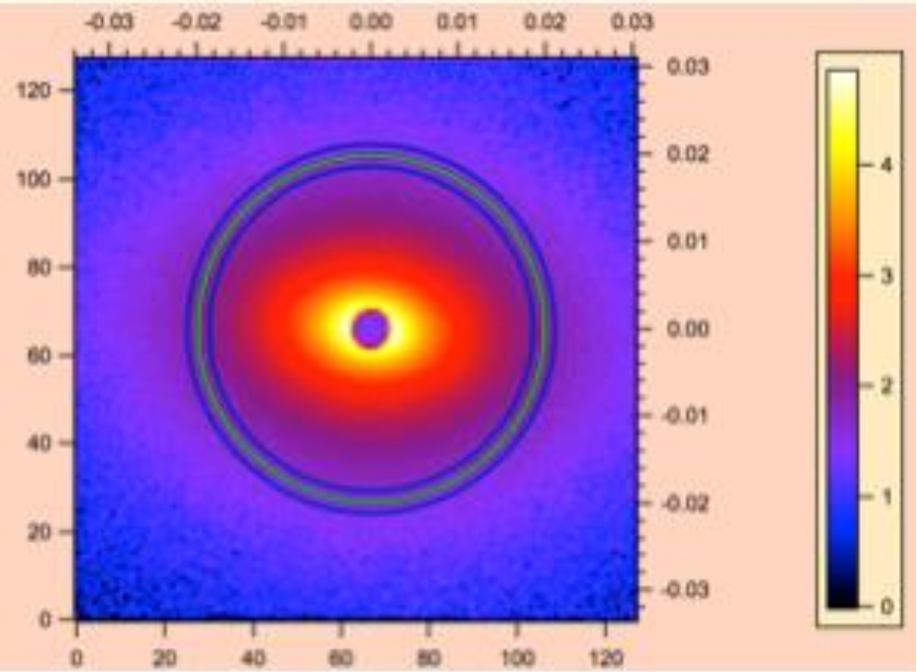
High-Pressure SANS and USANS

Hydrostatic Cell



- Increasing pressure = greater H_2O in pores
- Decreasing pressure illustrates nano-confinement (H_2O remains in the pores)
- Possible explanation for irreversible hydraulic fracture fluid loss

Oedeometer Cell

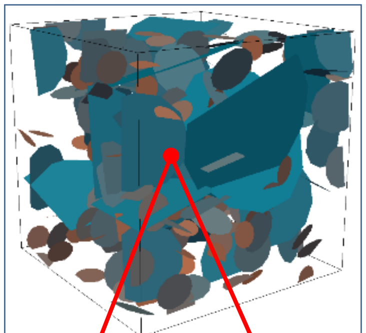


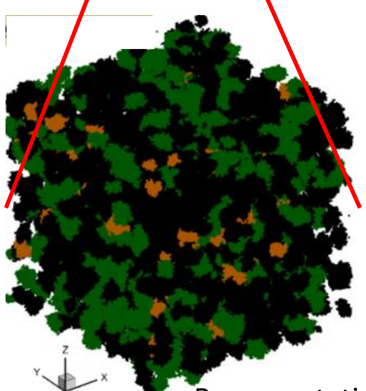
- Ellipsoidal pattern demonstrates anisotropy in pore geometry parallel to bedding planes
- The effects of compressive stress and pore pressure are length scale dependent: little effect at < ~33 nm; significant effect from 100 nm to 10 µm.

Analysis of the Production Curve

3b. Lattice Boltzmann Modeling

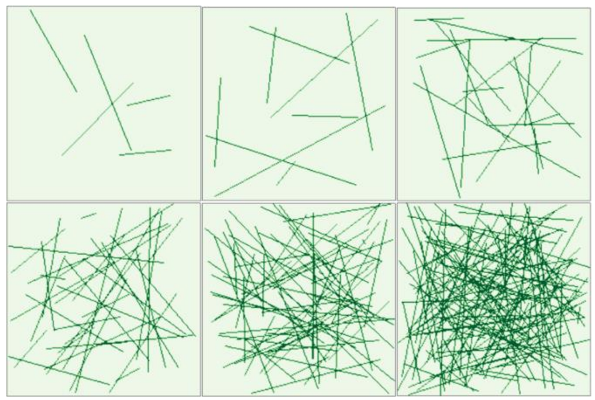
Block of shale with microfractures 3x3x3 cm

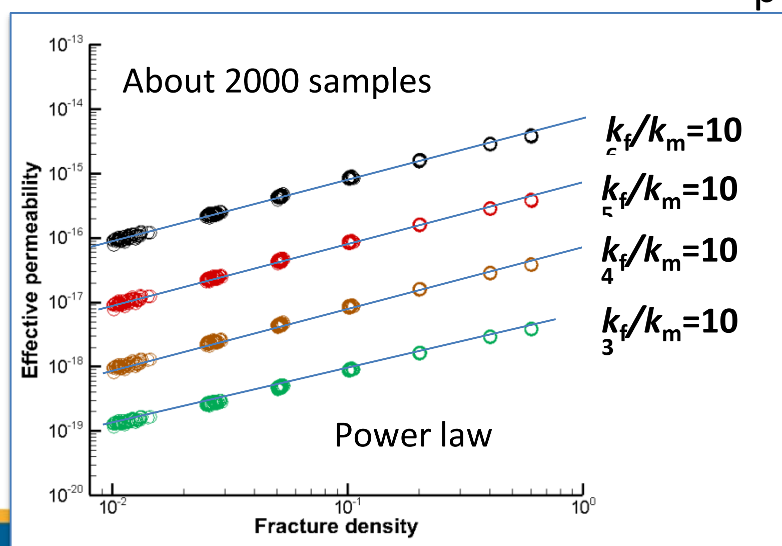




Representative matrix sample 150x150x150 μm

2D slice through shale illustrating increasing fracture density

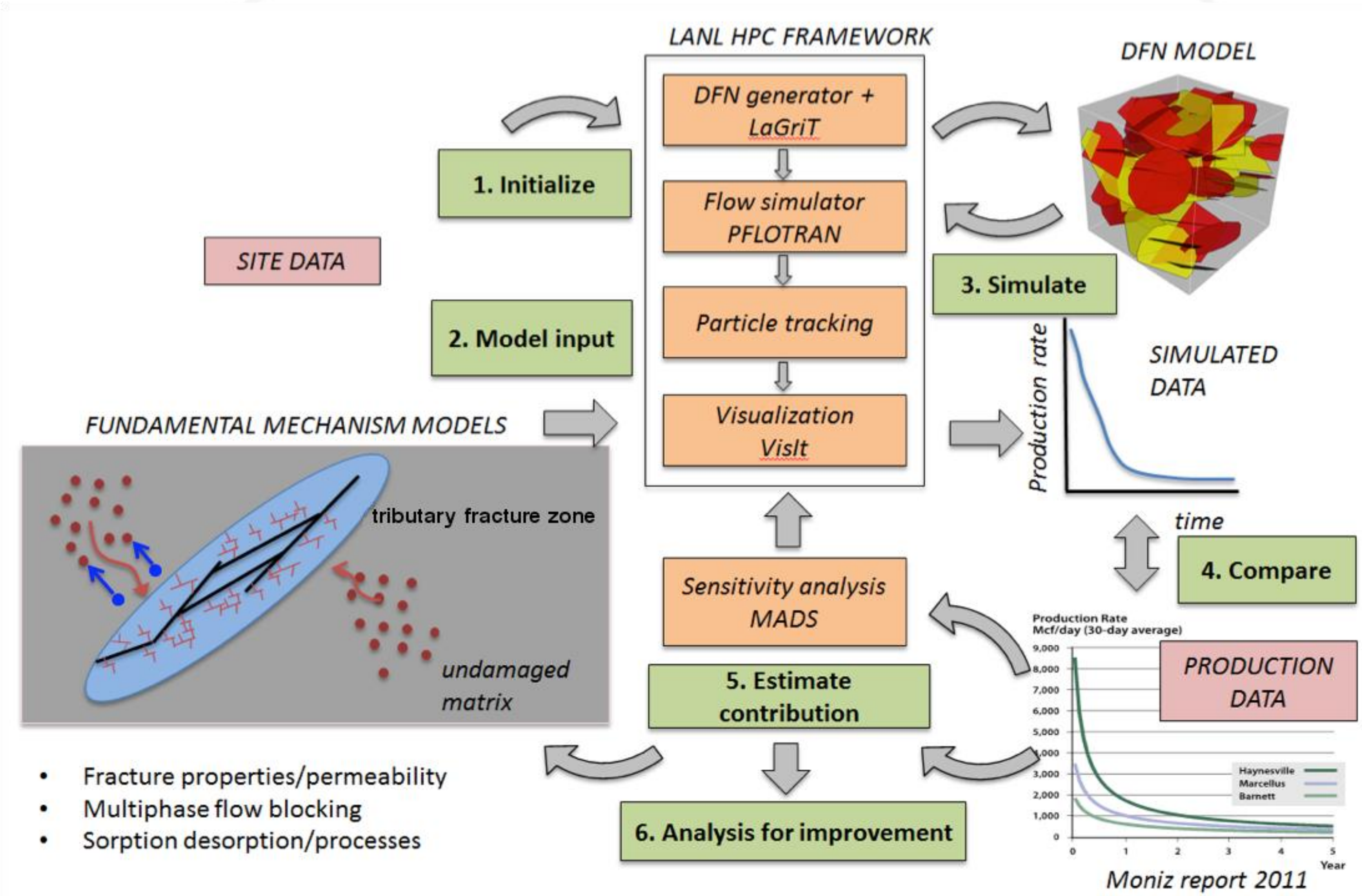


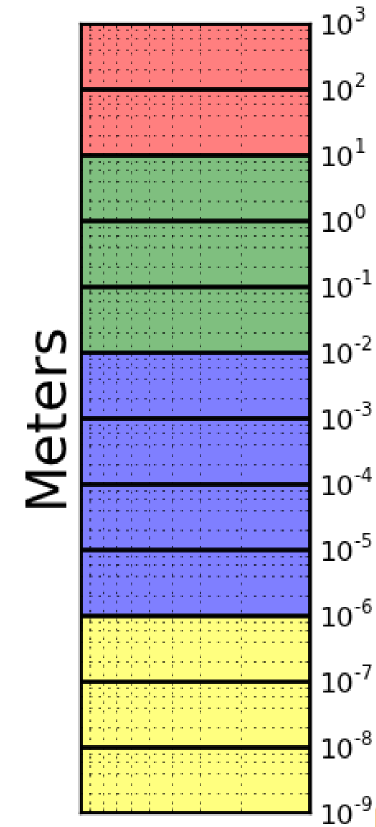


- First computational study to include both fracture and matrix properties
- Power-law relationship discovered between fracture density and effective permeability

Chen et al. (in review) AGU Books

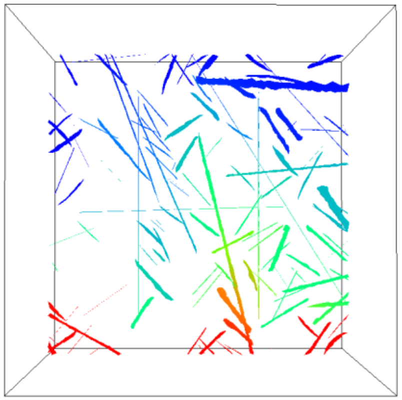
Analysis of the Production Curve
4. Integrated Predictive Tool



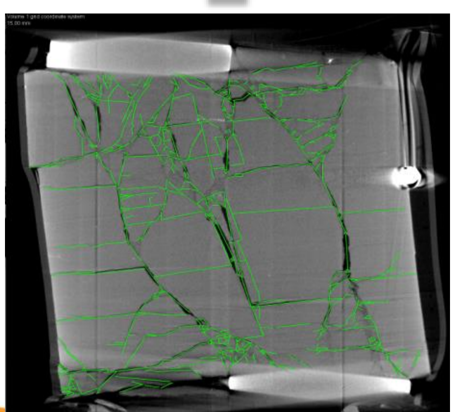


Validated by laboratory experiments and field data

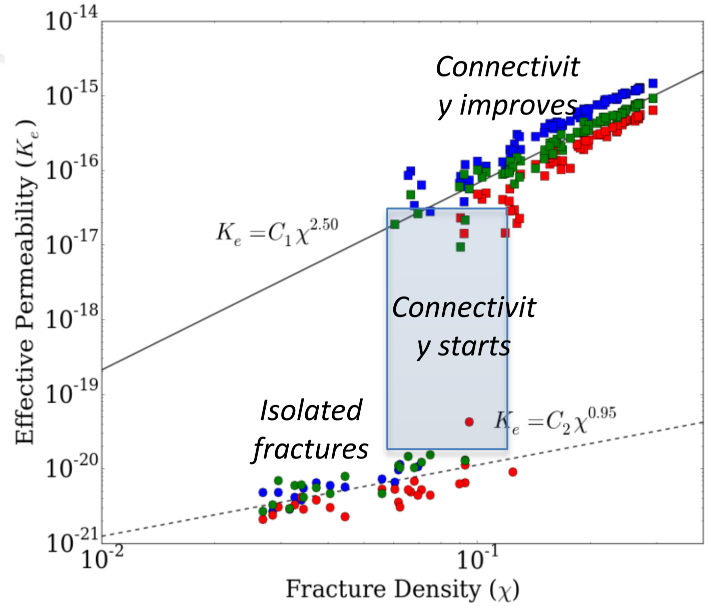
Integration: Tributary Fracture Zone

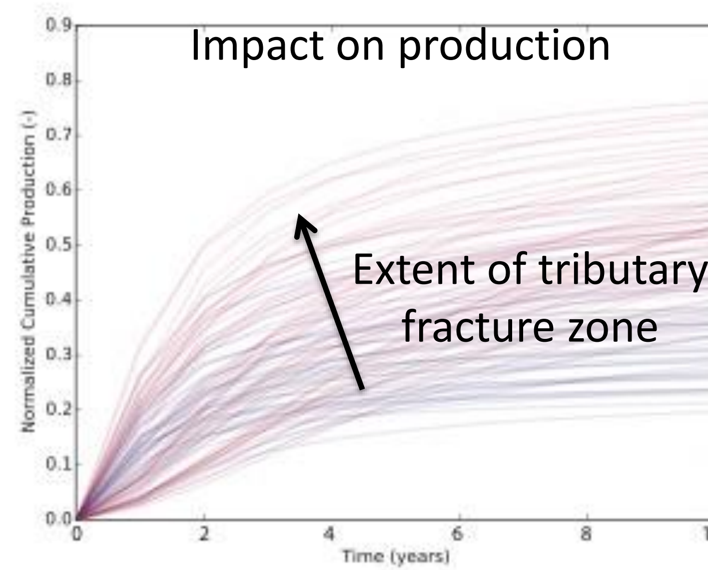


smaller scale DFN O(m)



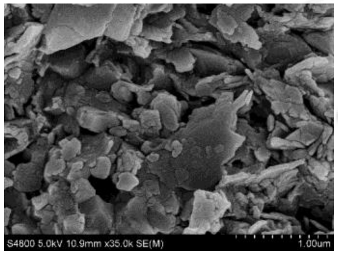
Fracture stochastics from triaxial experiments *(Carey et al. 2015, J Unconv. O&G Res.)*



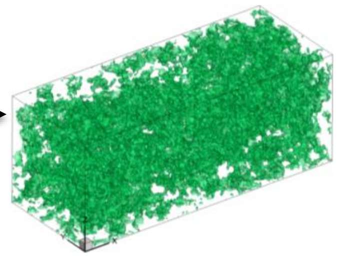


Integration: Shale Matrix

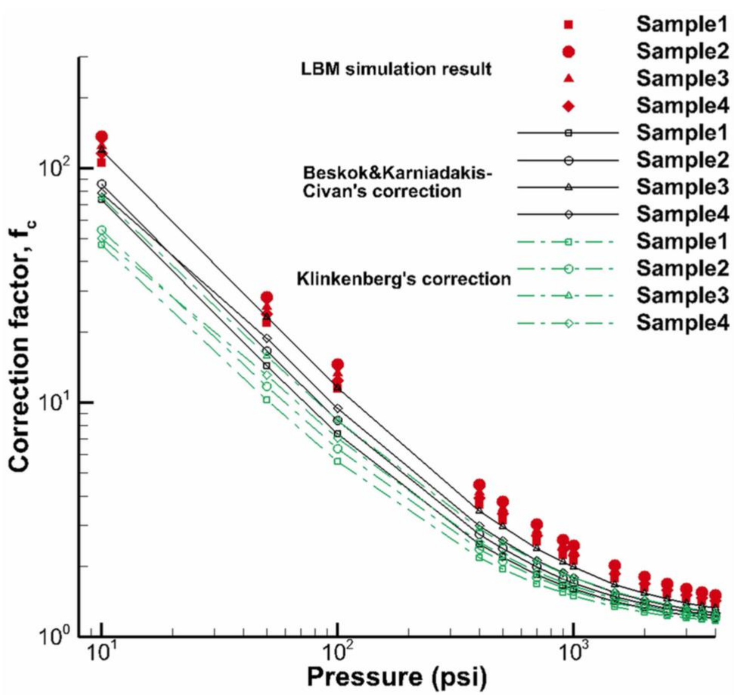
Reconstructed 3D shale structure



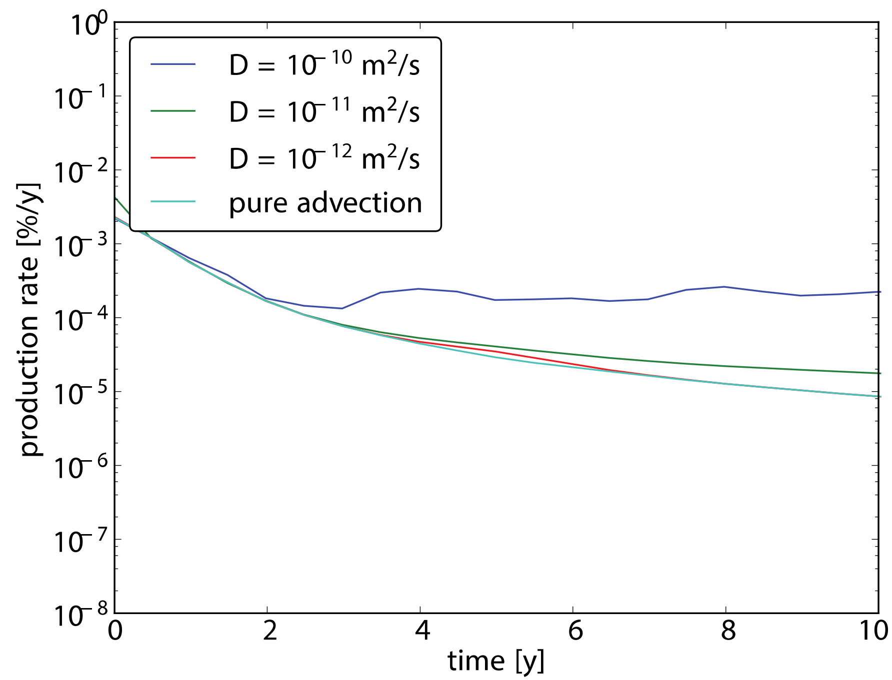
SEM image of shale obtained from Sichuan Basin



Markov Chain Monte Carlo (MCMC) method



Impact on Production



Chen et al. (2015) Sci. Reports; Chen et al. (2015) Fuel; Karra et al. (2015) WRR

Accomplishments to Date

- Developed a DFN modeling based capability *dfnWorks* with mechanistic models for transport processes to perform production curves
- Incorporated physics-based models for fracture flow, matrix diffusion, desorption
- Combined *dfnWorks* to decision support framework to perform parameter estimation, inverse modeling, sensitivity analysis and also uncertainty quantification
- Performed reservoir-scale simulations with the mechanisms to infer the sensitivities

Accomplishments to Date

- Measurement of fracture and transport at reservoir conditions are significantly different than those measured by standard techniques
  - New experimental systems allow direct visualization and measurement of fracture behavior, fluid flow and pore-distribution of fluids
  - Profound impact of P-T conditions on transmissivity of tributary fracture zone
- Quantified permeability of shear fractured Utica shale
  - Demonstrated the difference in the high permeability of shale fractured at shallow depths (brittle) versus low permeability at greater depth (ductile) and the transition from transmissive to non-transmissive fractures

Accomplishments to Date

- Measurements of hydrocarbon production from fracture networks with high-pressure/temperature microfluidics system
  - Significantly enhanced production with the use of soluble fracturing fluid (supercritical CO_2)
- Revealed diverse microstructure/mineralogy within the same shale core sample (heterogeneous zones of the Wolfcamp shale) and among shales from different formations (Wolfcamp, Marcellus).
- Discovered the confinement effect of nanopores on fluids using SANS and LBM
  - SANS - On increasing pressure, more fluid (water, hydrocarbon) fills into nanopores. Upon releasing the pressure, the fluid remains in the nanopores. This hysteresis is due to a nanopore confinement effect, which would not occur in large pores of conventional reservoirs.

Accomplishments to Date

  - LBM - The apparent permeability of nanoporous media is no longer equal to the intrinsic permeability, as in conventional porous media. The nanopore effect (or Knudsen diffusion) needs to be taken into account and the correction factor can amount to 50.
- Developed a new capability – an oedometer system coupled with SANS, enabling probing fluid behavior at combined high pore pressure and uniaxial stress conditions.
- Preliminary integration of core- and micro-scales data with reservoir-scale modeling.

Synergies & Collaborations

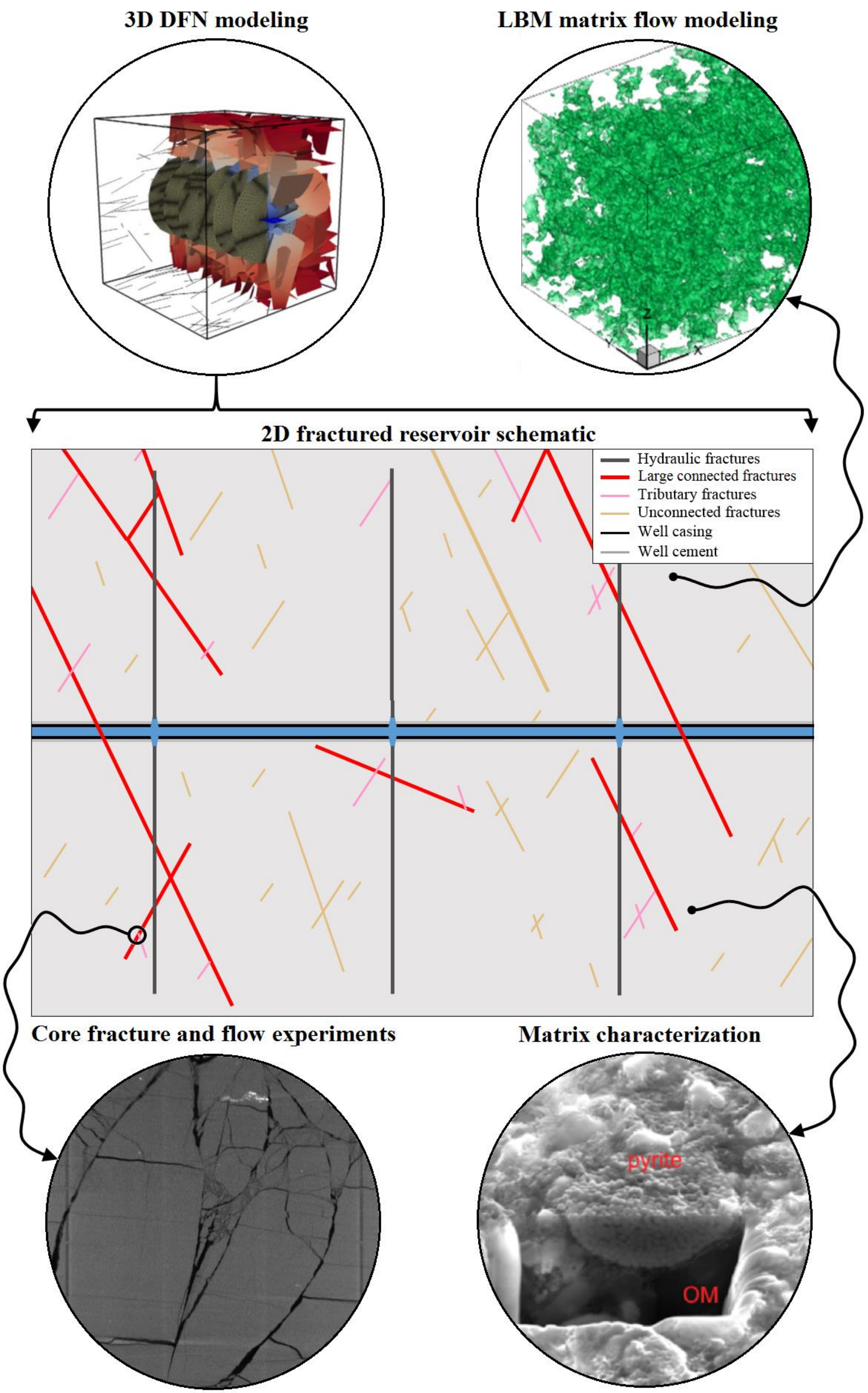
- Synergies with CO_2 Sequestration (caprock behavior)
- Multi-Lab Synergies and Collaborations
  - Common field site: Marcellus and MSEEL
  - Ongoing collaborative study among NETL, LBL and LANL on shear-induced permeability
  - LBL work on proppants adds much needed dimension to LANL and NETL studies of fracture permeability and applications in *dfnWorks*
  - LBL work on swelling behavior will complement LANL and NETL characterization and will feed analyses of imbibition processes
  - NETL larger-displacement, longer-term studies will complement LANL and LBL investigations of fracture permeability
  - NETL experience with microfluidics will complement LANL studies using Marcellus shale
  - Geochemistry collaboration between LANL, SLAC and NETL

Conclusions/Key Findings

- Analysis of production curves using discrete fracture networks provides predictions of reservoir behavior during production
  - Initial production peak (~1 year) is due to free gas in the fractures
  - Increasing tributary zone fracture density increases gas production to the larger fractures and boosts medium-term production
  - Long-term production (2–10 years) ties to matrix diffusion, desorption, etc.
- Measurement of fracture and transport at reservoir conditions are significantly different than those measured by standard techniques
  - New experimental systems allow direct visualization and measurement of fracture behavior, fluid flow and pore-distribution of fluids
  - Profound impact of P-T conditions on transmissivity of tributary fracture zone
- Fluid behavior in pores & small fractures is impacted by multiphase effects
  - Miscible hydraulic fracturing fluids can sweep fractures during depressurization
  - Water enters matrix under pressure but shows hysteresis on depressurization
  - LBM methods can adequately quantify Knudsen diffusion effects at nanoscale in shale

Moving Forward

- Focus on field site: MSEEL
  - Utilize integrated capabilities of national laboratory teams
- Detailed investigation (e.g., influence of fracture characteristics) of production curves provides ground-truth and insight into which processes matter
- Use experimental studies on common Marcellus sample set to quantify fracture and transport properties
- Build computational models from experiment and field data to create tools to enhance productivity



3D DFN modeling
LBM matrix flow modeling
2D fractured reservoir schematic
Hydraulic fractures
Large connected fractures
Tributary fractures
Unconnected fractures
Well casing
Well cement
Core fracture and flow experiments
Matrix characterization
pyrite
OM

Questions?

Appendix: Organization Chart

- George Guthrie (Project Lead)
  - Task 1: Reservoir-scale Modeling (Satish Karra PI)
    - Jeffrey Hyman
    - Nataliia Makedonska
    - Hari Viswanathan
    - Richard Middleton
  - Task 2: Core-scale experiments (Bill Carey PI)
    - Mark Porter
    - Joaquín Jiménez-Martínez
    - Luke Frash
  - Task 3: Micro-scale (Hongwu Xu PI)
    - Li Chen
    - Mei Ding
    - Rex Hjelm
    - Qinjun Kang
    - Rajesh Pawar

Appendix: Gantt Chart

	FY16	FY17	FY18
Understanding Basic Mechanisms in Natural Gas Production using Reservoir-Scale Modeling	Concluded		
Experimental Study of In Situ Fracture Generation and Fluid Migration in Shale.	Concluded		
Probing Hydrocarbon Fluid Behavior in Nanoporous Formations to Maximize Unconventional Oil/Gas Recovery	Concluded		
Assessment of current approaches to understanding Hydrocarbon production			
Large-scale fracture controls on hydrocarbon production in the Marcellus shale			
Tributary zone fractures (small-scale) contributions to hydrocarbon production in the Marcellus shale			
Fundamental Matrix Properties in Relation to Predicting Hydrocarbon Migration into Fractured Marcellus Shale			
Integration of Large-Scale Fractures, Tributary Fractures and the Matrix			

Appendix: Publications

- S. Karra, N. Makedonska, H. S. Viswanathan, S. L. Painter, and J. D. Hyman. Effect of advective flow in fractures and matrix diffusion on natural gas production. *Water Resources Research*, 2015
- J. D. Hyman, S. Karra, N. Makedonska, C. W. Gable, S. L. Painter, and H. S. Viswanathan. dfnworks: A discrete fracture network framework for modeling subsurface flow and transport. *Computers & Geosciences*, 84:10-19, 2015
- N. Makedonska, J. D. Hyman, S. Karra, S. L. Painter, C. W. Gable, and H. S. Viswanathan. Evaluating the effect of internal aperture variability on transport in kilometer scale discrete fracture networks. *Advances in Water Resources*, 94:486-497, 2016
- G. Aldrich, J. D. Hyman, S. Karra, C. W. Gable, N. Makedonska, H. S. Viswanathan, J. Woodring, and B. Hamann. Analysis and visualization of discrete fracture networks using a flow topology graph. *IEEE Transactions on Visualization and Computer Graphics*, doi:10.1109/TVCG.2016.2582174, 2016
- J. D. Hyman, G. Aldrich, H. S. Viswanathan, N. Makedonska, and S. Karra. Fracture size and transmissivity correlations: Implications for 1 transport simulations in sparse three-dimensional discrete fracture networks following a truncated power law distribution of fracture size. *Water Resources Research*, doi:10.1002/2016WR018806, 2016

Appendix: Publications

- Carey, J. W., Frash, L. P., and Viswanathan, H. S. (2016). Dynamic Triaxial Study of Direct Shear Fracturing and Precipitation-Induced Transient Permeability Observed by In Situ X-Ray Radiography. In 50th US Rock Mechanics / Geomechanics Symposium held in Houston, Texas, USA, 26-29 June 2016.
- Frash, L. P., Carey, J. W., Ickes, T., and Viswanathan, H. S. (in press). High-stress triaxial direct-shear fracturing of Utica shale and in situ X-ray microtomography with permeability measurement. Journal of Geophysical Research.
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