Mechanistic Approach to Analyzing and Improving Unconventional Hydrocarbon Production

U.S. Department of Energy

National Energy Technology Laboratory

Mastering the Subsurface Through Technology Innovation, Partnerships and Collaboration:

Carbon Storage and Oil and Natural Gas Technologies Review Meeting

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Los Alamos NATIONAL LABORATORY EST. 1943

Part 1: Tributary zone fractures (small-scale) contributions to hydrocarbon production in the Marcellus shale

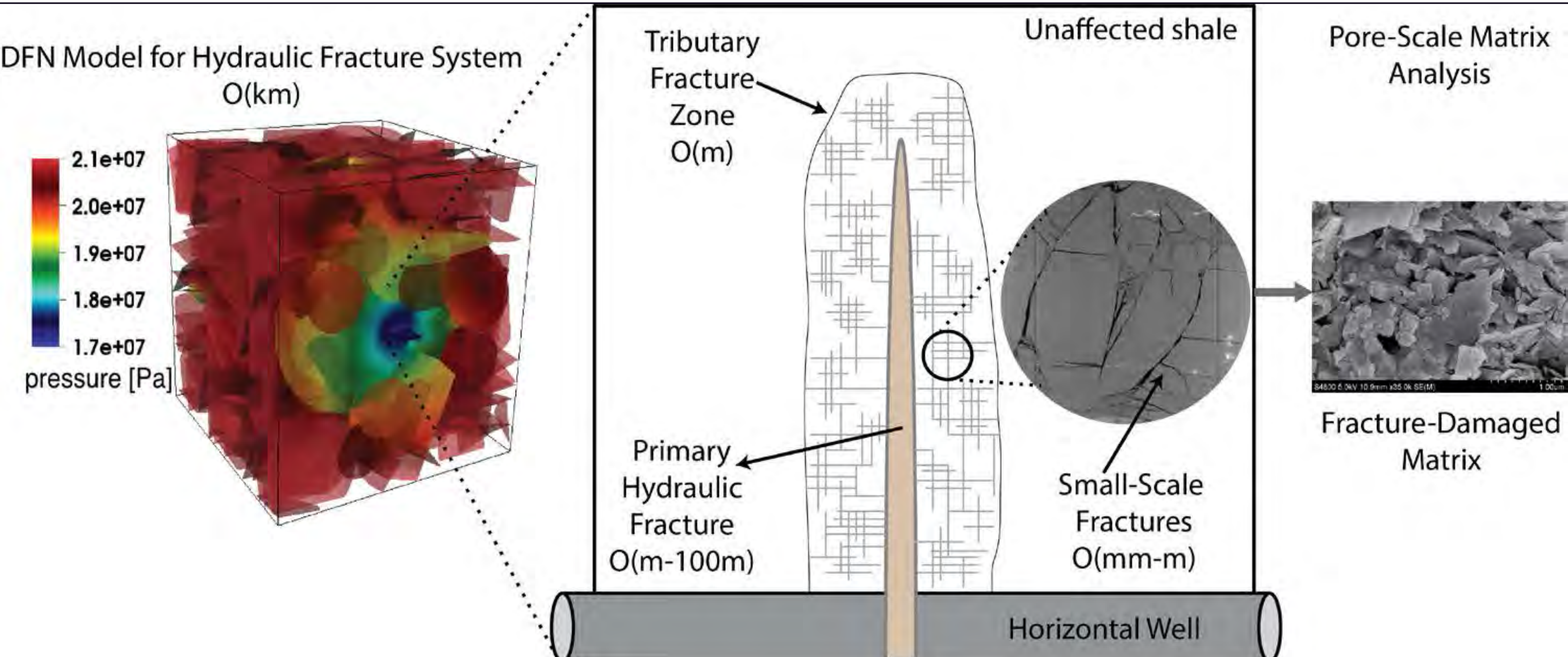
Presentation by Bill Carey

NNSA National Nuclear Security Administration

Overview of Project

***Target:** Enable technological solutions to improve recovery efficiency through an improved fundamental understanding*

Across Scales



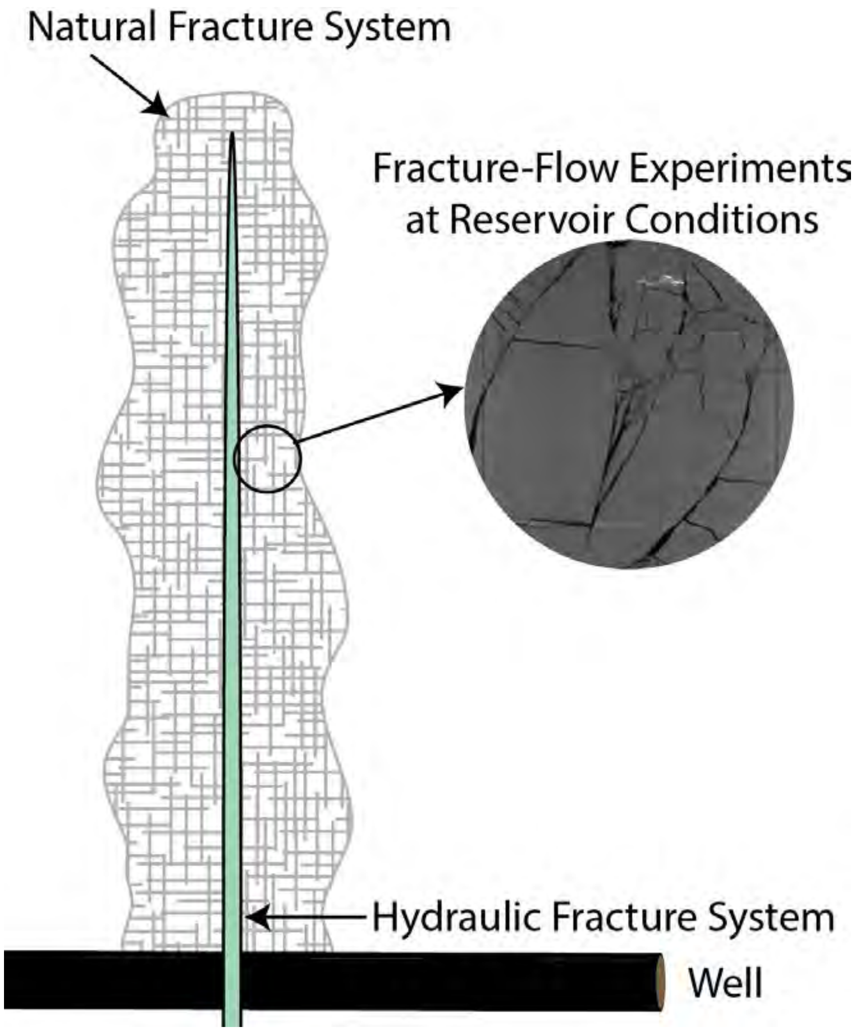
Karra @ 1:35

Carey @ 1:15

Kang @ 1:55

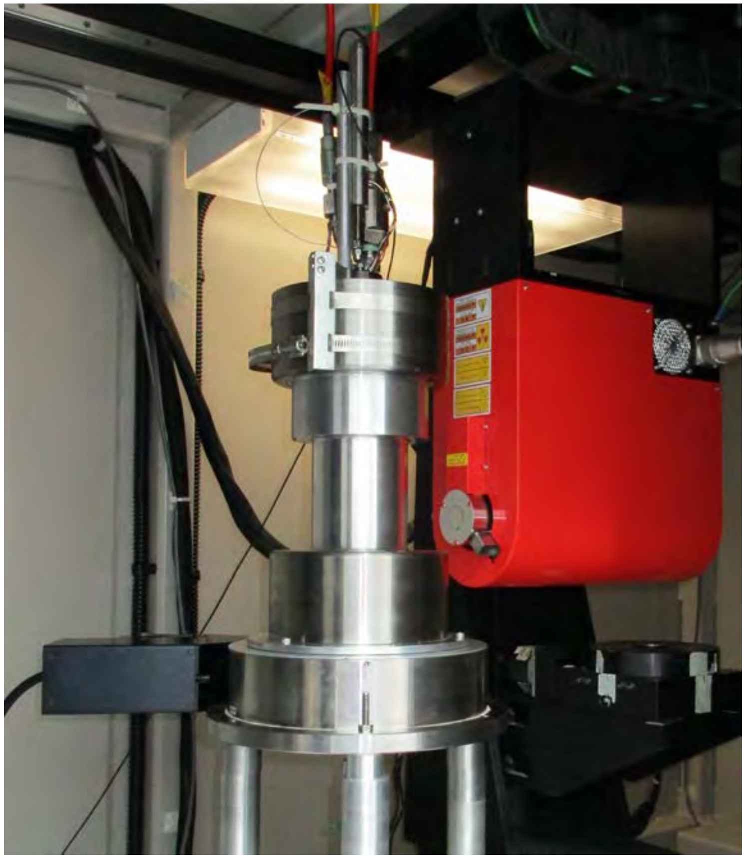
Technical Status: Tributary Fracture Zone Studies

- Completed experimental characterization of Marcellus shale carbonate-rich lithology
  - Fracture permeability as a function of stress at which fracture forms
  - Fracture permeability as a function of changes in stress after fracture formation
- Developed experimental approach for study of fracture drainage processes using microfluidics

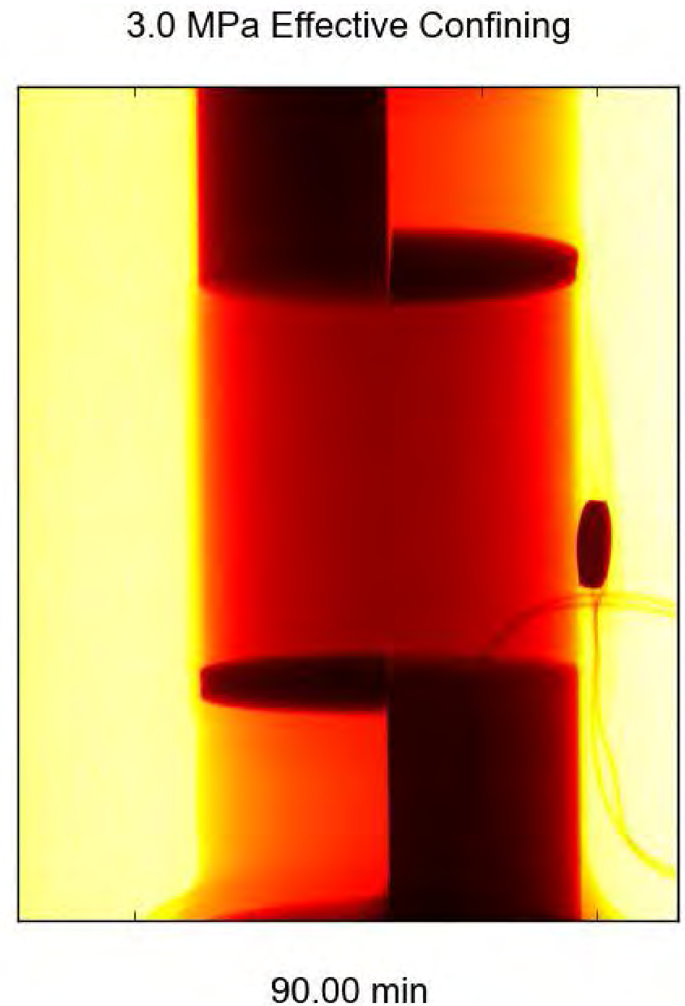


Experimental Approach: Triaxial Direct Shear Coreflood with X-ray Tomography

Carey et al., J. Unconv. O&G Res., 2015; Frash et al. (2016) JGR; Frash et al. (2017) IJGGC



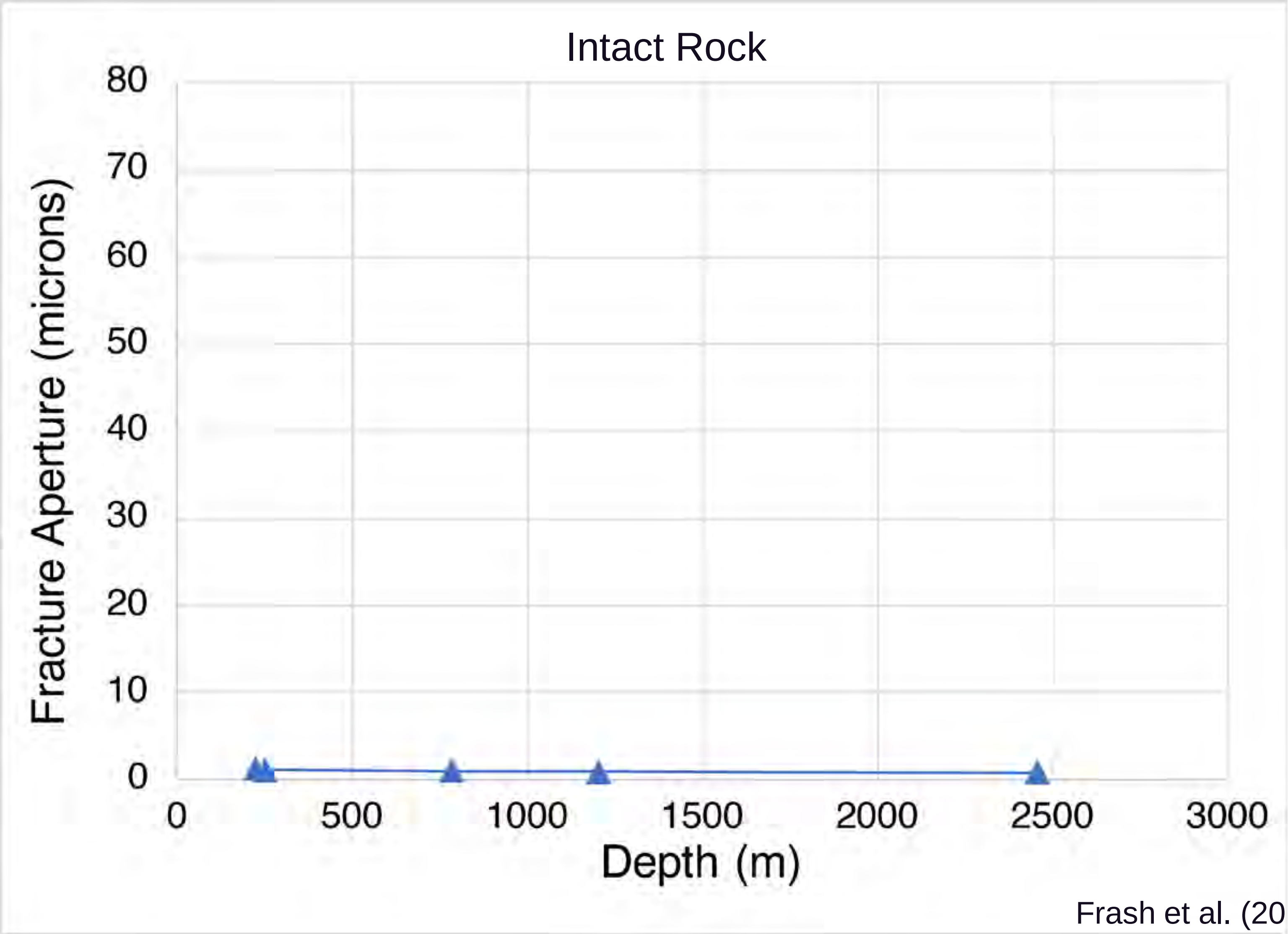
- Max Pressure: 34.5 MPa (5,000 psi)
- Max Axial Load: 500 MPa (70,000 psi)
- Max Temperature: 100 °C



X-ray radiography and tomography at reservoir conditions

What controls the transmissivity of natural and stimulated fractures?

Hypothesis: The transmissivity of fracture networks can be predicted through a analysis of rock properties and stress conditions (deformation depth).



Frash et al. (2017) IJGGC

Tasks 4.1-2: What controls the transmissivity of natural and stimulated fractures?

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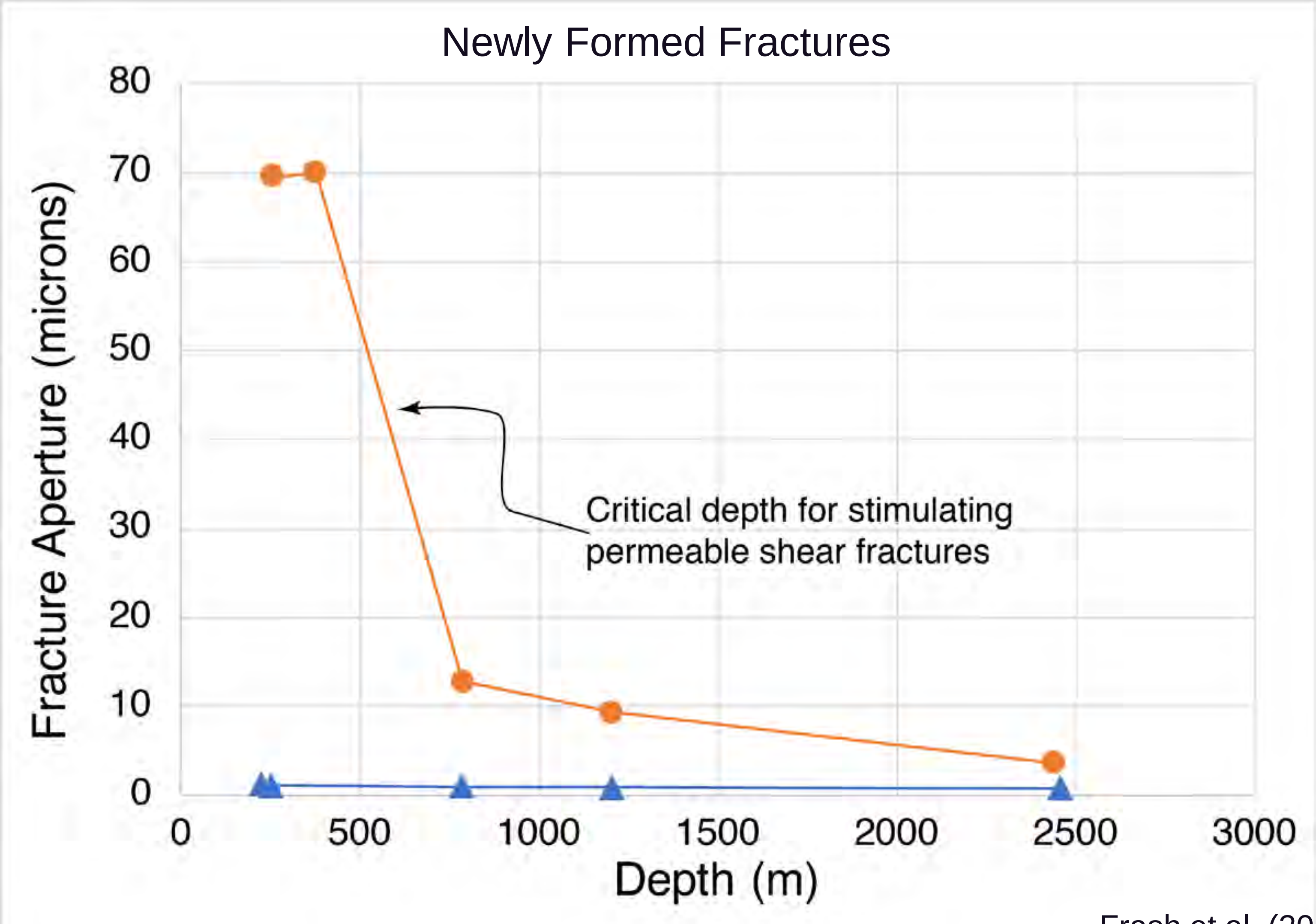

Frash et al. (2017) IJGGC

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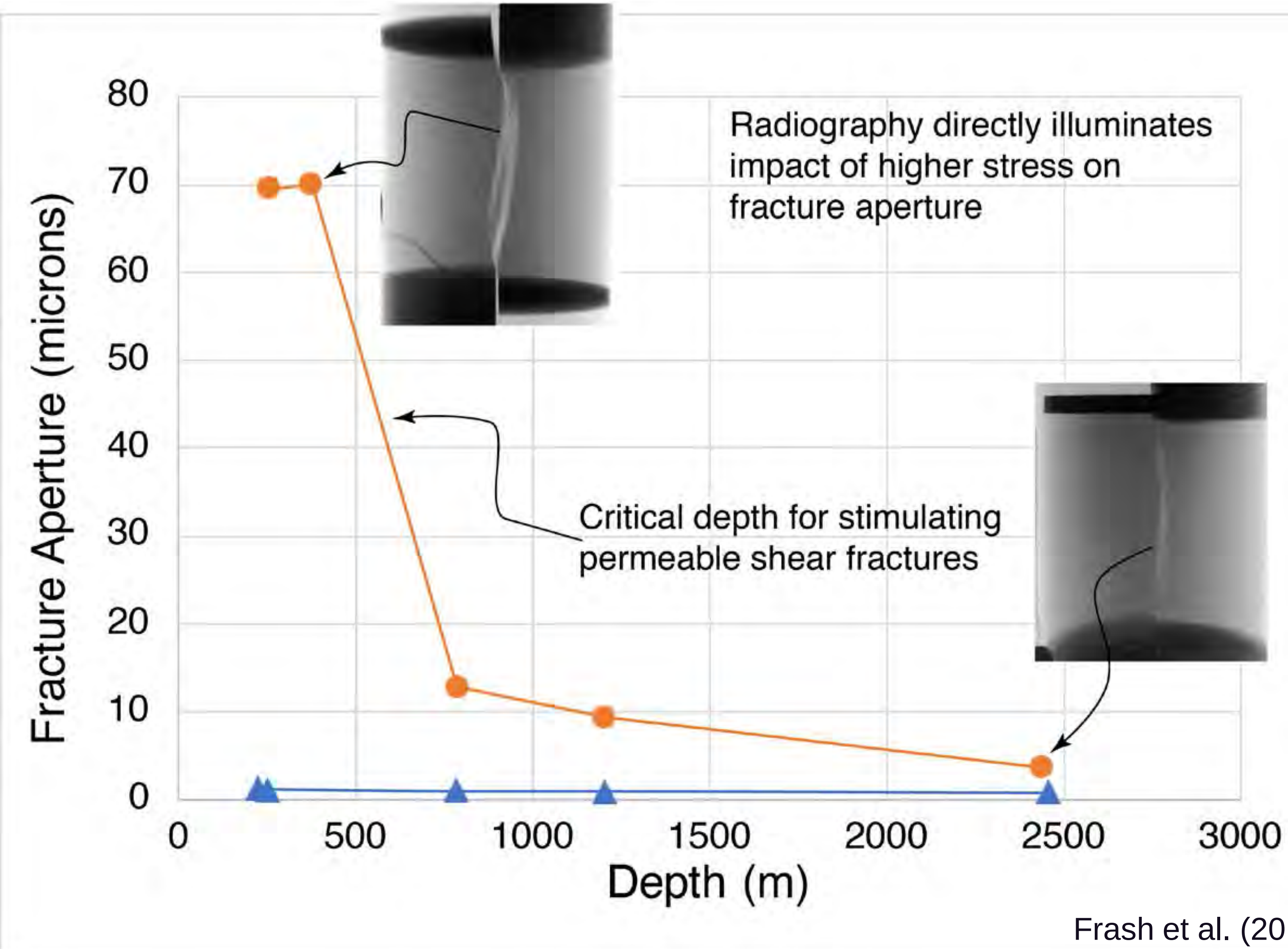

Frash et al. (2017) IJGGC

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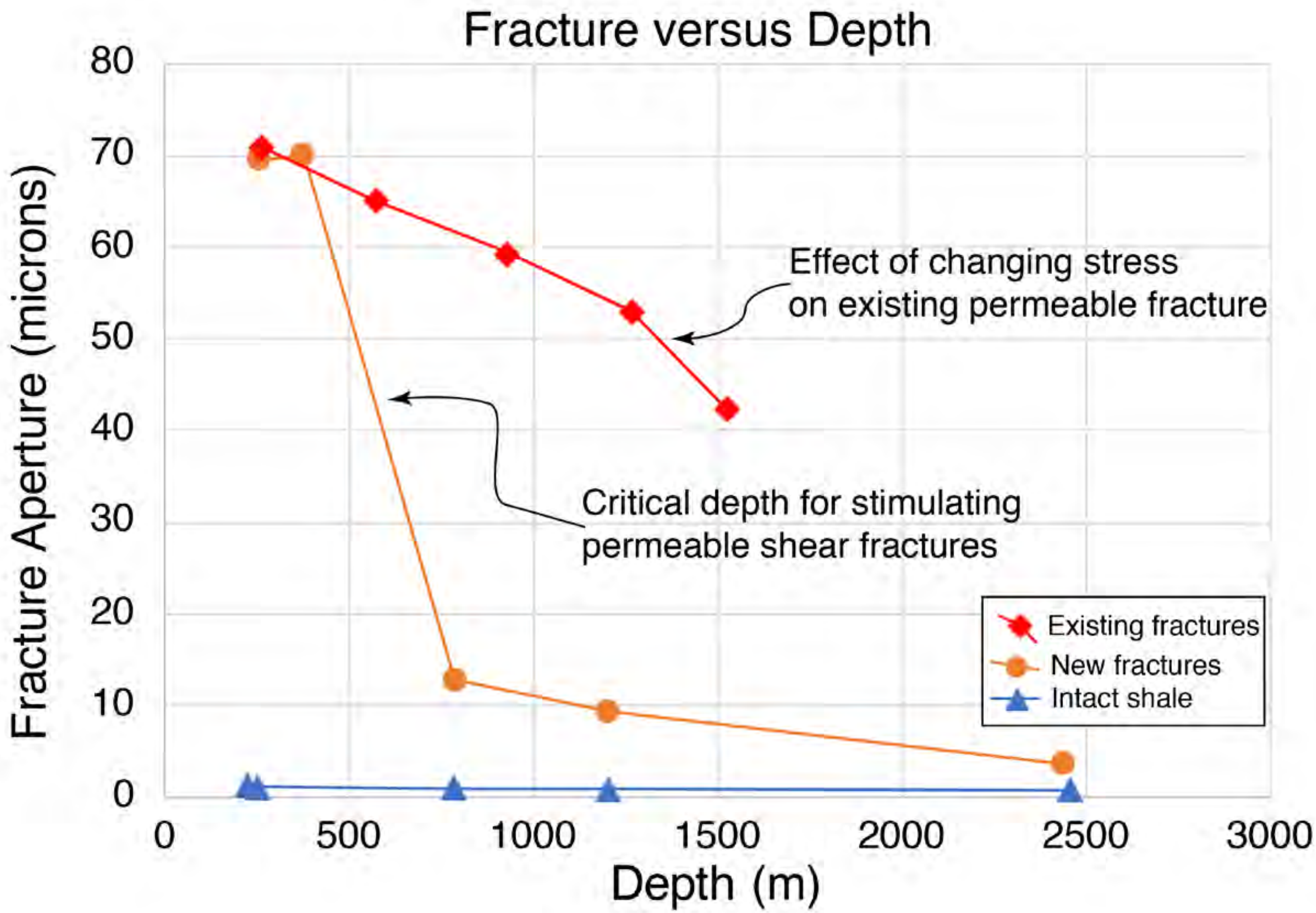
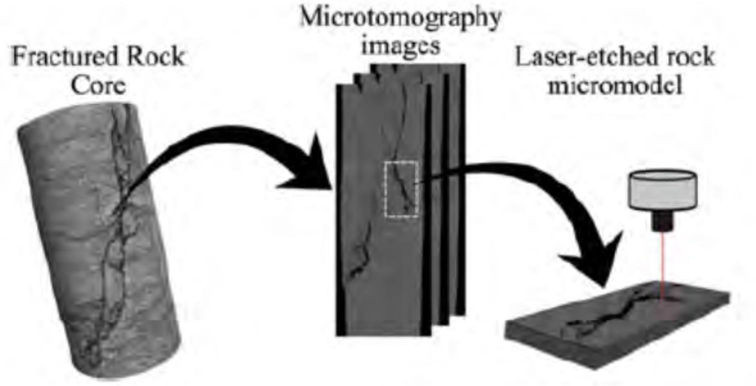
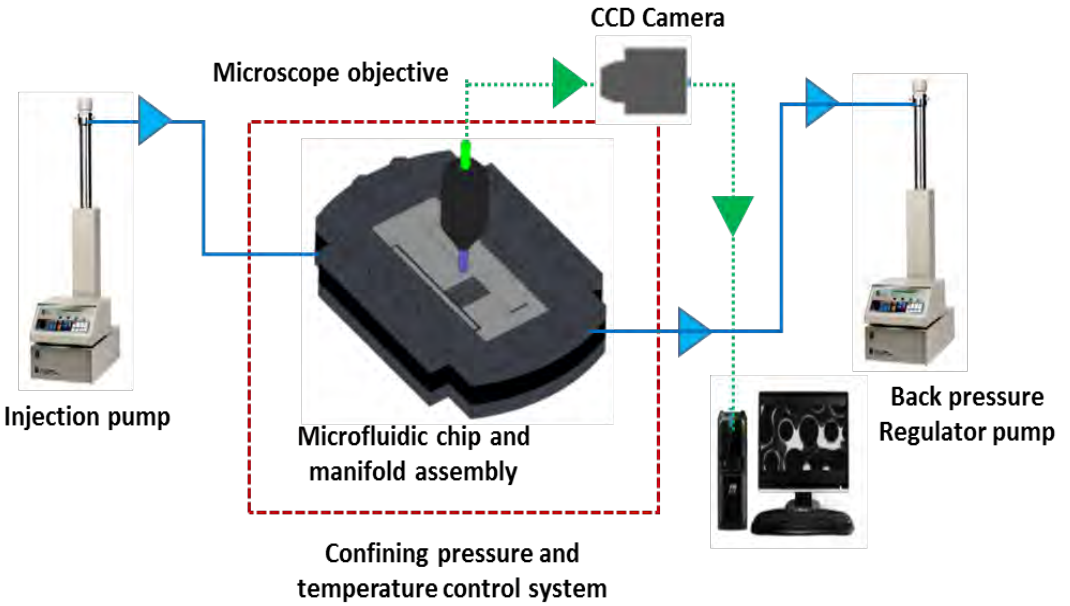


Frash et al. (2017) IJGGC

Experimental Approach: High P-T Microfluidics using Shale

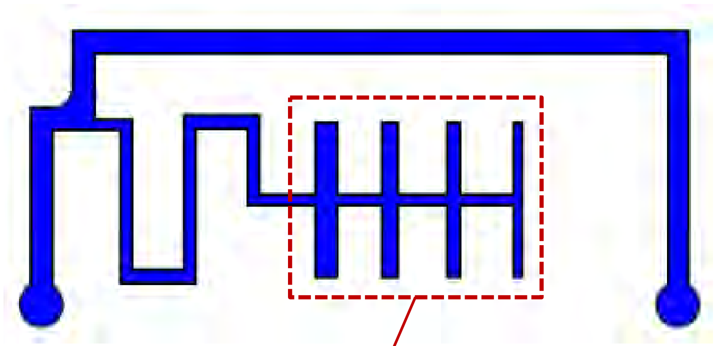




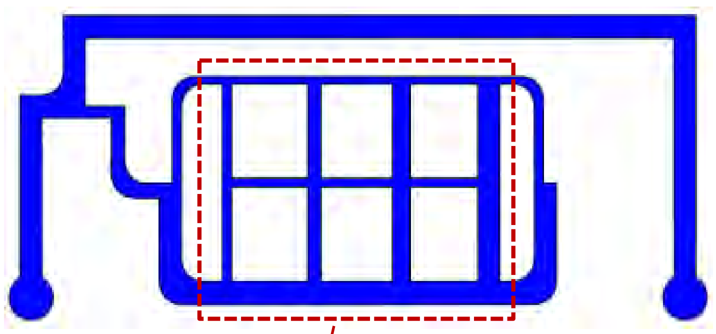
- Max Pressure: 10.3 MPa (1,500 psi)
- Max Temperature: 80 °C
- 3 simultaneous fluids among water, oil, CO_2, N_2, Xe,...

Approach: Experimental study of oil displacement in complex fractures

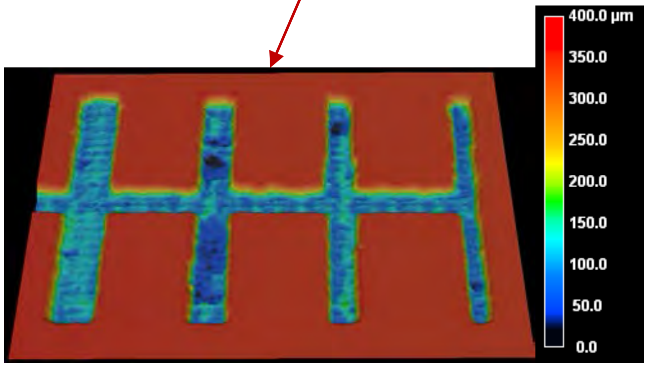
a) Closed end fracture network



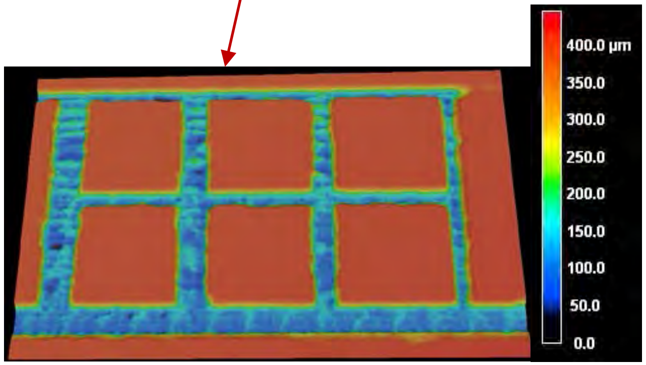
b) Connected fracture network



c)



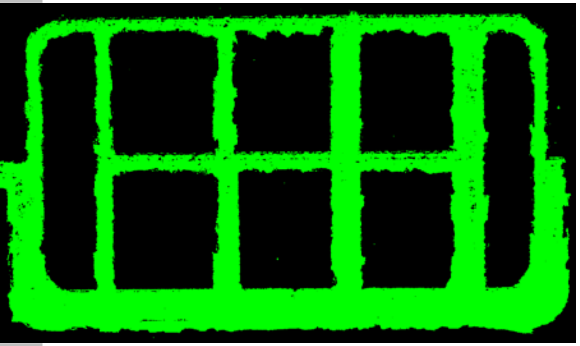
d)



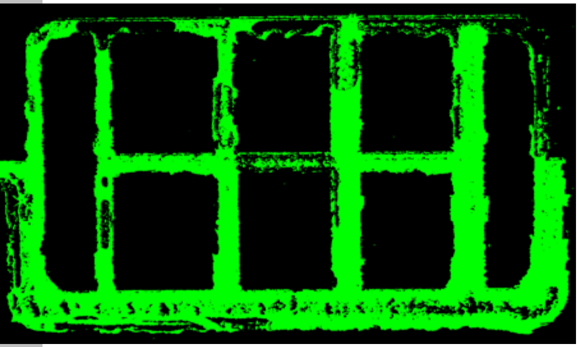
Profilometry showing fracture geometry

Oil recovery with CO_2 depressurization in connected fracture network

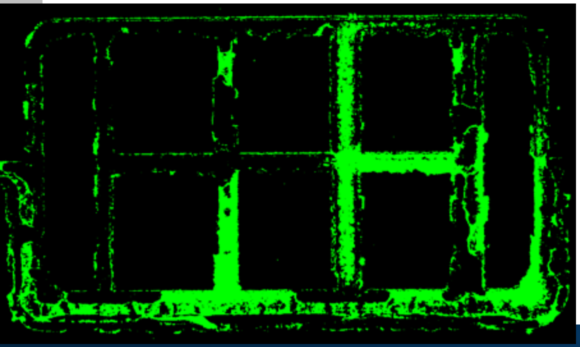
a) Initial Oil saturation, P = 10 MPa



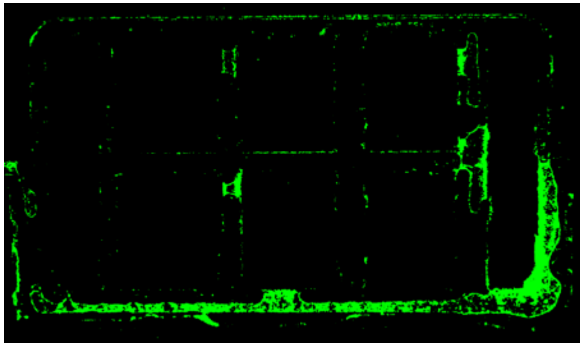
b) Oil saturation = 82%, P = 7 MPa



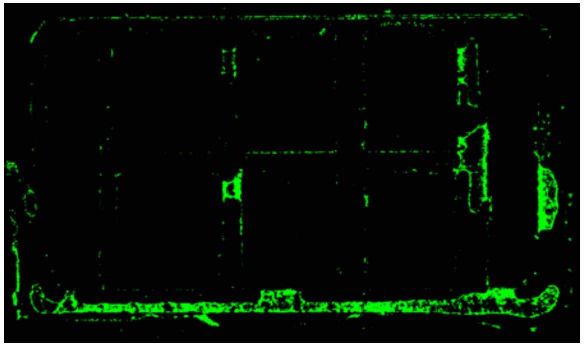
c) Oil saturation = 40%, P = 5 MPa



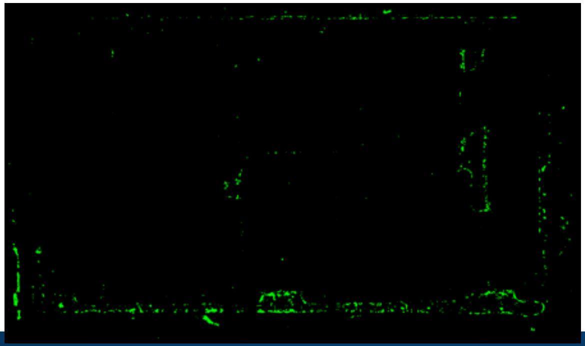
d) Oil saturation = 15%, P = 2.5 MPa

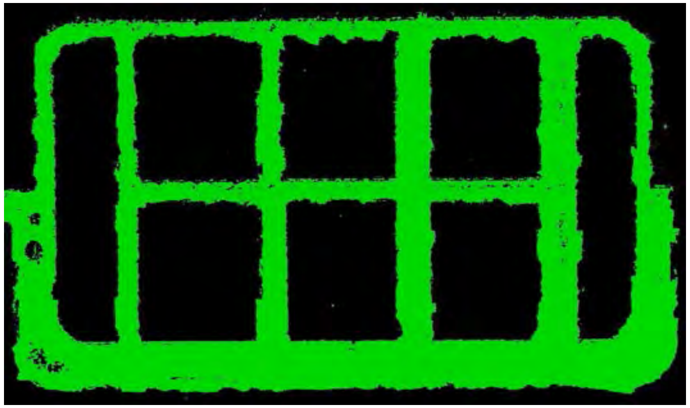


e) Oil saturation = 10%, P = 2 MPa



f) Oil saturation = 5%, P = 1MPa





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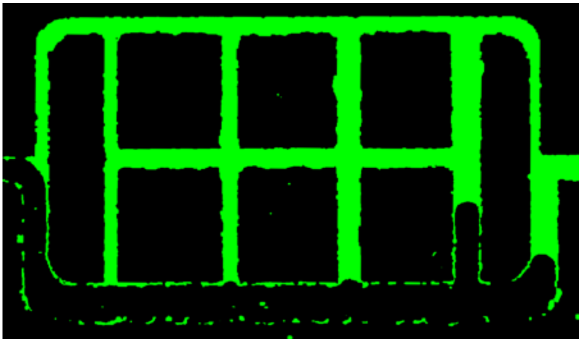
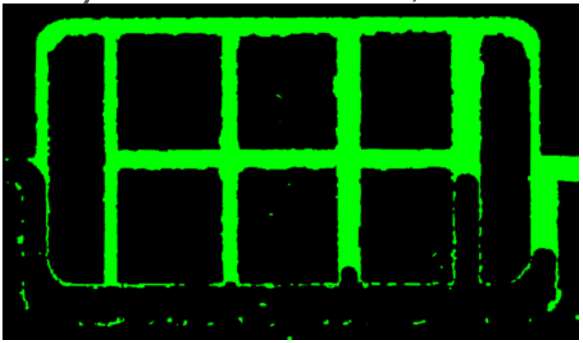
Oil recovery with N_2 depressurization in connected fracture network

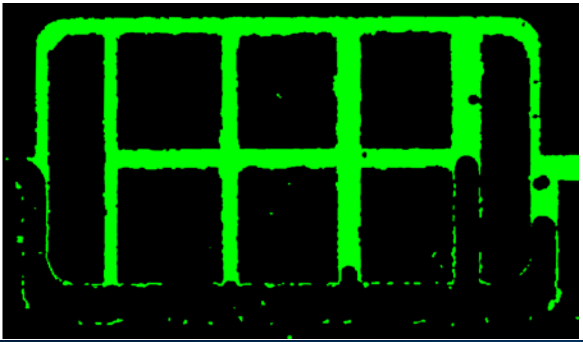
a) Initial Oil saturation, P = 10 MPa



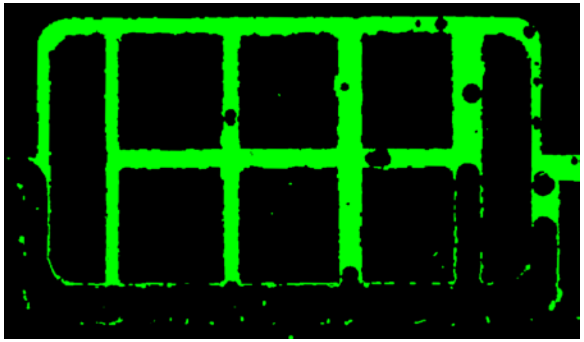
b) Oil saturation = 93%, P = 7 MPa



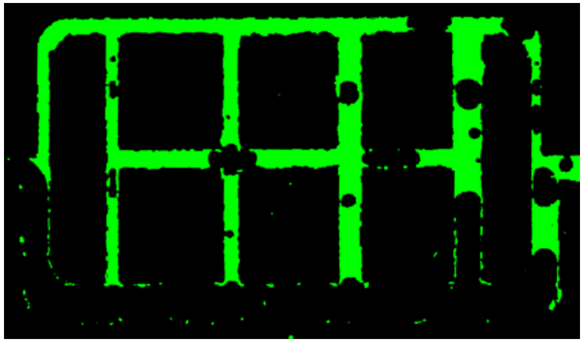
c) Oil saturation = 92%, P = 3.5 MPa



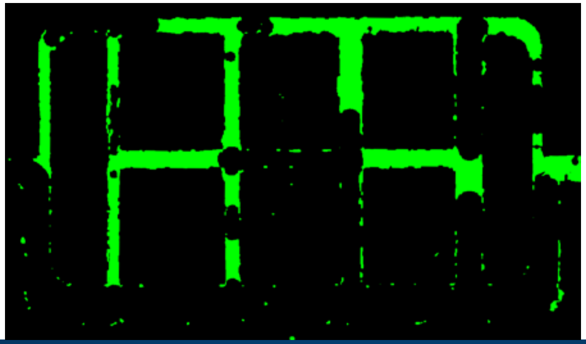
d) Oil saturation = 85%, P = 2.8 MPa

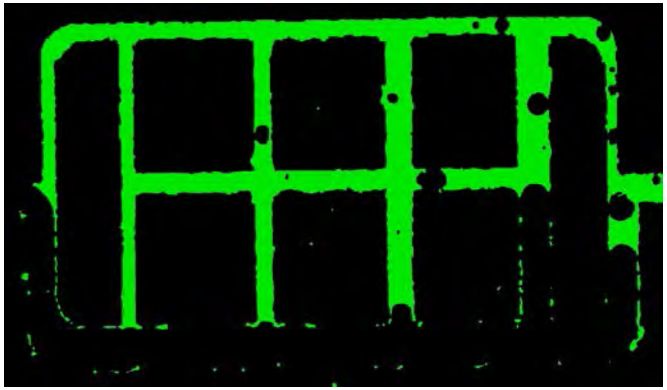


e) Oil saturation = 80%, P = 0.5 MPa



f) Oil saturation = 60%, P = 0.2 MPa





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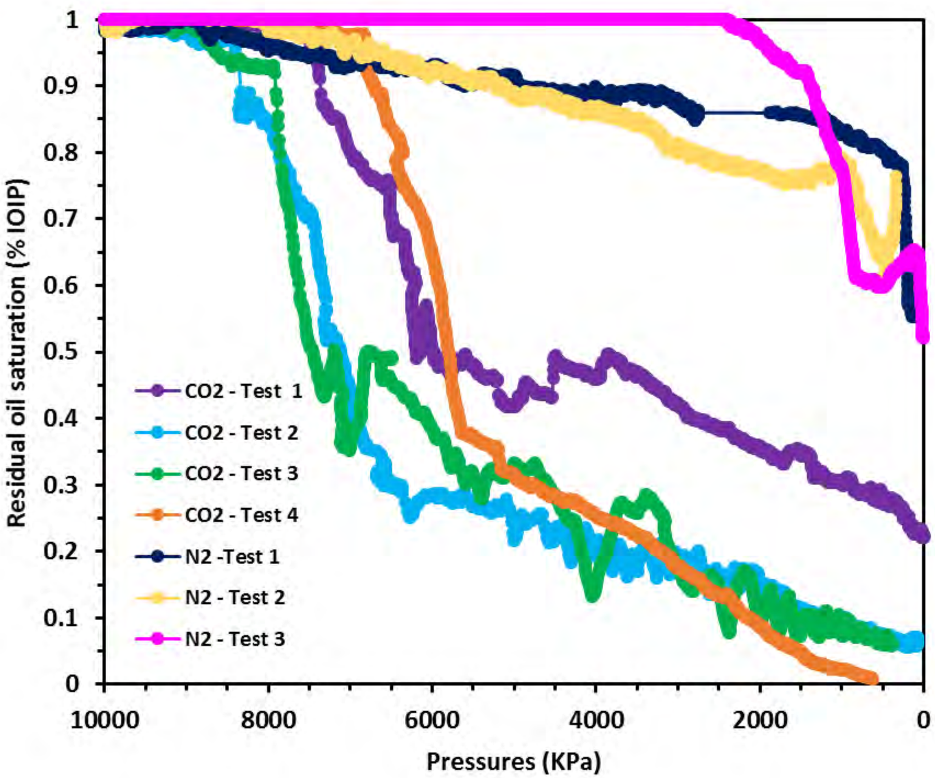
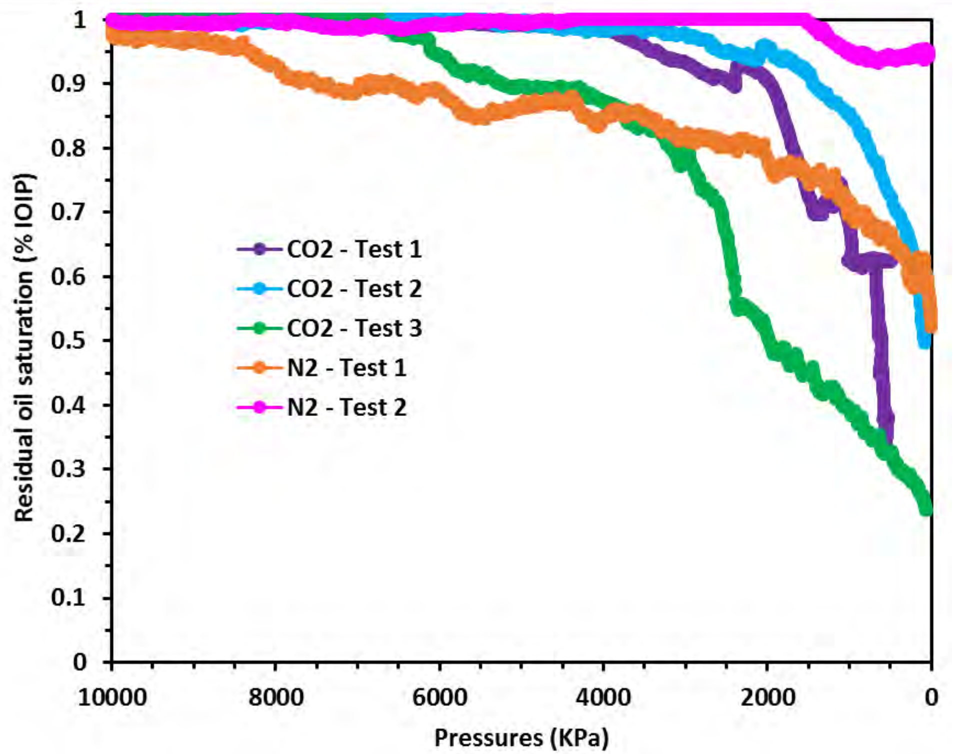
Oil Recovery Efficiency: Supercritical CO_2 very effective

Connected Fracture Network



Dead-end Fracture Network



- Complex fracture systems trap oil unless injected fluid is soluble in oil
- Connected fractures enhance oil mobility but allow bypass and stranding
- Previous work conducted as part of DE-FE 0024311 with Texas Tech on CO_2-EOR in shale

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Lessons Learned

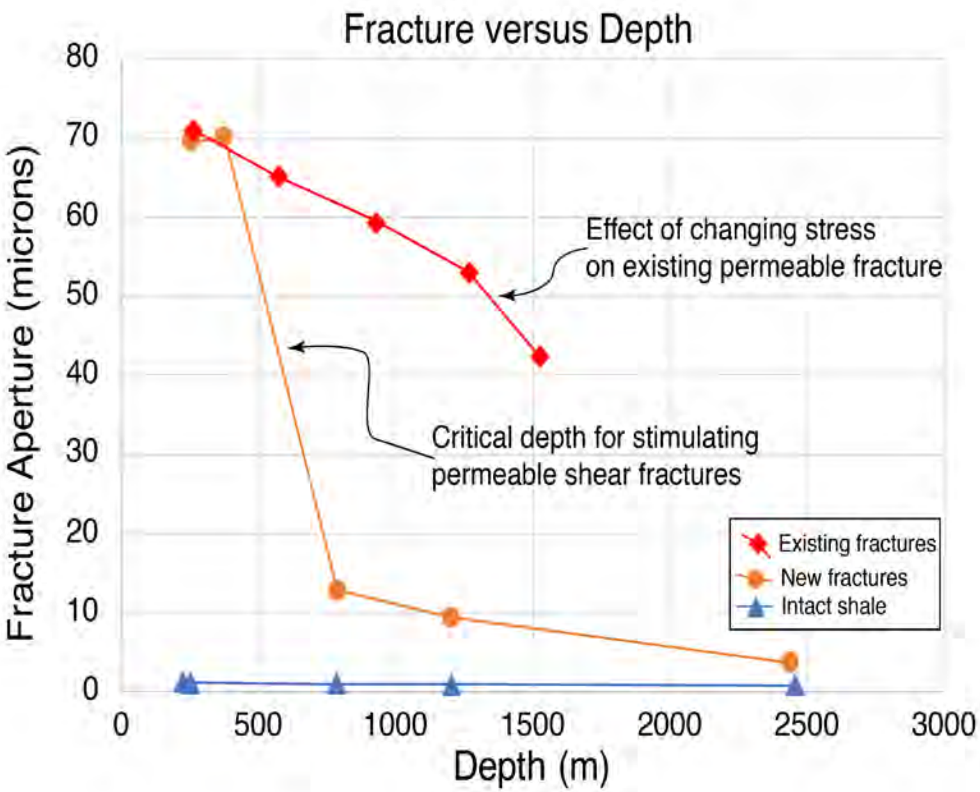
- **Very important difference between the stress at which fractures form and changes in stress after fracture formation**
- **Unknown at this time whether these differences persist through geological time**
  - Important in relation to reactivation of fractures
- **Lithology/mineralogy plays an important role that is not yet understood**
- **Miscible fluids can be very effective for enhanced recovery even in dead-end fracture systems**

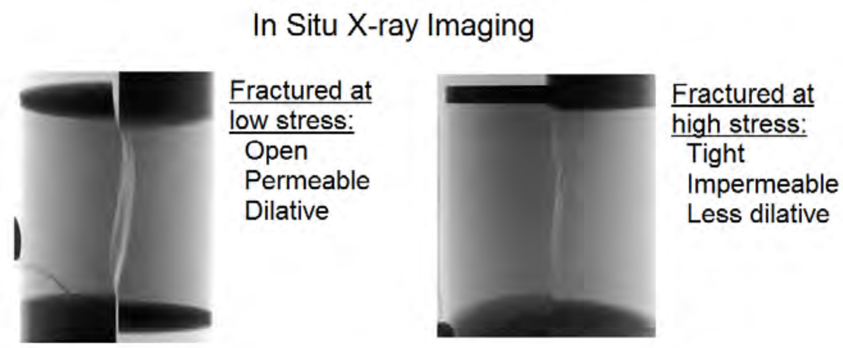
Synergy Opportunities

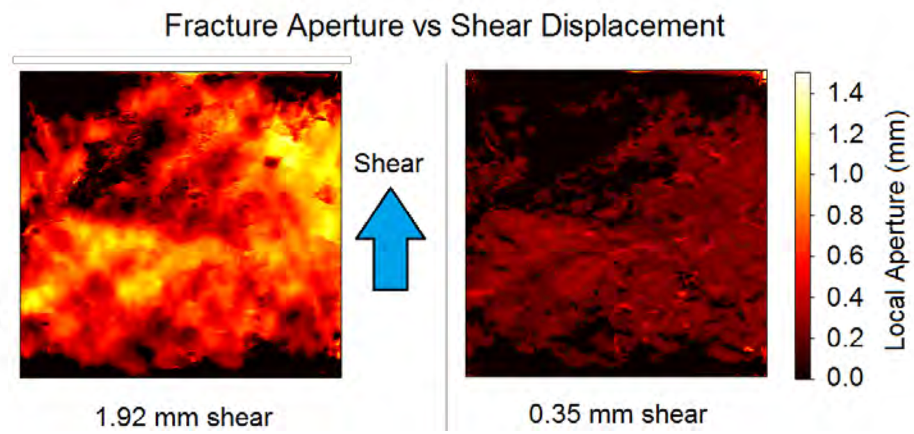
- Marcellus Shale Energy and Environment Laboratory: Work with MSEEL core
- USEEL and Permian Basin projects also represent good collaboration opportunities
- National Risk Assessment Project: Analysis of leakage risk from caprock
- SubTER: Permeability manipulation
- Other projects in Oil and Gas Fundamental Science Portfolio
- Emphasizing geochemistry (SLAC), nanopore interactions (Sandia), hydraulic fracturing propagation (LBNL)
- Caprock studies for CO_2 sequestration: Colorado School of Mines, NETL, UT-Austin
- Fracture behavior and stress/strain: Penn State, Clemson, UT-Austin

Accomplishments to Date

We postulate that fracture permeability is subject to critical transitions that can are key to design of hydraulic fracturing operations.







- We quantified the impact of fracture depth (i.e., stress) on fracture aperture (permeability) for the carbonate-facies of the Marcellus shale
- We identified a critical stress controlling formation of permeable fractures and hypothesize that this impacts the design of hydraulic fracturing operations
- Next, we apply the new theory to more lithologies and to the development of improved hydraulic fracturing designs

Appendix

Benefit to the Program

- Measurement of the permeability and multiphase flow behavior in small-scale fractures comprising the tributary fracture zone
- Improving the efficiency of hydraulic fracturing through production curve analysis
- Determination of key mechanisms controlling unconventional oil and gas migration
- Development of tools to analyze production cures and thereby enhance hydrocarbon production

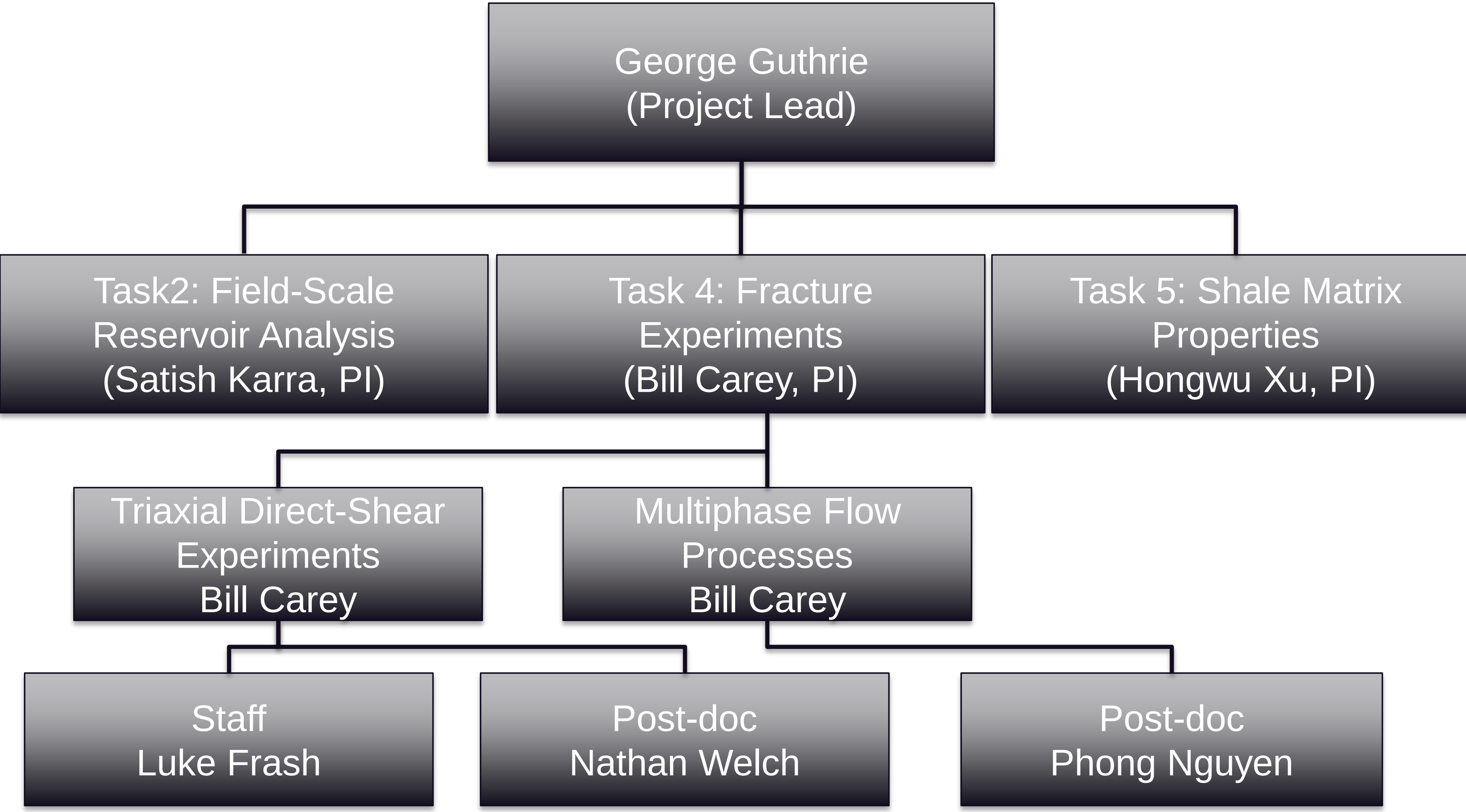
Project Overview
Goals and Objectives

- **Quantification of fracture-network permeabilities**
  - Use state-of-the-art facilities to measure and characterize permeability at reservoir conditions

- **Determine influence of reservoir stress conditions on fracture permeability**
  - Fracture-permeability as a function of the conditions of fracture formation (i.e., depth) and as a function of changing stress conditions (potential effect of fracture closure)

- **Multiphase fluid flow processes**
  - ˜Use high P/T microfluidics system to directly observe and characterize multiphase flow in fractures

Organization Chart



Gantt Chart

	Gantt Chart	FY16		FY17				FY18					
Task#	Task	Q3	Q4	Q1	Q1	Q2	Q4	Q1	Q2	Q3	Q4	Product	Dependencies
4.0	Tributary zone fractures (small-sca contributions to hydrocarbon produc in the Marcellus sha												Start requires results from 2.1
4.1	Quantification of fracture-network permeabilities of th Marcellus shale					complete						Complete. Results described in report detailing the variation in permeability as a function of geomechanical conditions for the Marcellus shale. Results published in Frash et al. (2017)	
4.2	Impact of reservoir stress conditions on fracture permeabilit Marcellus shale						complete					Complete. Results described in report detailing the variation in permeability as a function of changing effective stress for fractures formed in the Marcellus shale. Results published in Frash et al. (2017).	
4.3	Multiphase fluid flo processes within fractured shale											Report detailing the mobility of hydrocarbon in fracture networks as a function of network complexity in the Marcellus shale	Requires results from 4.1
4.4	Integration of tribut fracture zone prope with DFN simulatio											Report detailing the potential effects of the tributary fracture zone on hydrocarbon productivity	Requires results from 3.1, 3.2, 4.1

Bibliography

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