Ozan Uzun
PhD Candidate, Petroleum Engineering
uzun@mines.edu

EVALUATING PRODUCTION PERFORMANCE OF PERMIAN BASIN WELLS TO IMPROVE HYDROCARBON RECOVERY

Drivers and Motivation

- **Permian Basin** is the most prolific oil and gas producing geologic basins in the United Sates—spanning West Texas and Southeastern New Mexico. It has produced more than 33.4 Bbbl of oil and 118 Tcf of natural gas during a 100-year period (EIA 2018).

- The ever-increasing water production and usage in the Permian Basin is a major issue and continues to require attention.

- Classical waterflooding in unconventional reservoirs is not plausible because of the small pore size and low permeability of the mudstone matrix. A practical alternative is cyclic gas injection.

Project Plan

Phase 1:

- Determine production characteristics of Delaware Basin wells
- Plan for several innovative EOR experiments

Phase 2:

- Build an appropriate numerical model to forecast future performance
- Prepare for the EOR experiments

Phase 3:

- Conduct EOR experiments
- Characterize field performance using numerical model (history match production data)
- Automated interpreation

Reservoir Properties

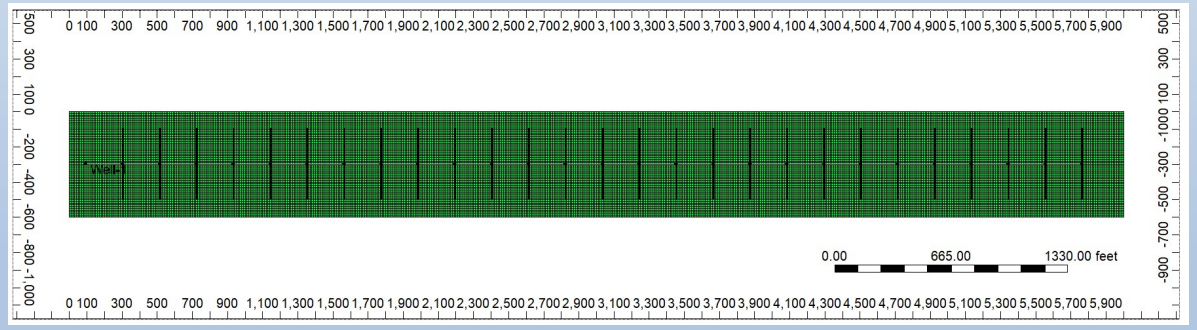
- Gross thickness: 600 ft
- Initial res pressure: 8175 psia
- Reservoir temp: 181.5 °F
- Porosity: 0.06
- Matrix permeability: 0.0003 mD
- Matrix pore compressibility: 1×10^{-5} $psia^{-1}$

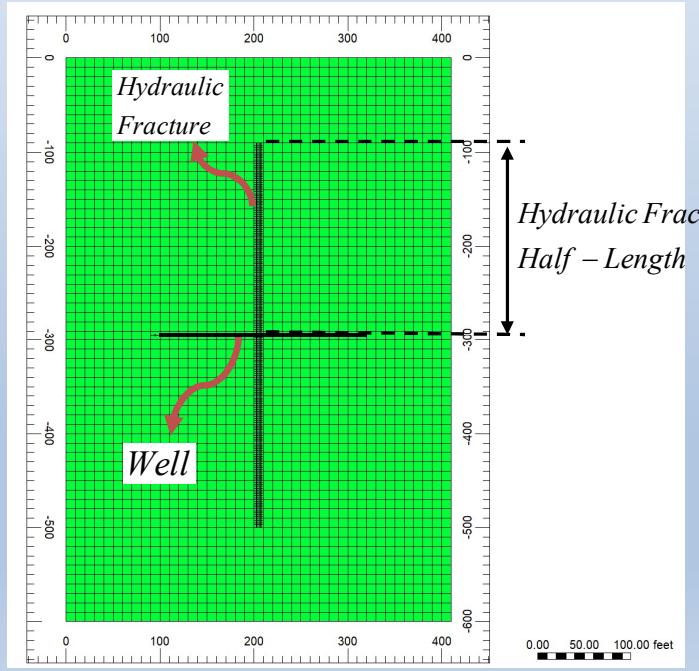
Numerical Model Grid Structure

- IMAX : 600
- JMAX : 60
- KMAX : 60

Δx : 10 ft
Δy : 10 ft
Δz : 10 ft

27 HF stages





Numerical Model Rock Properties

Matrix

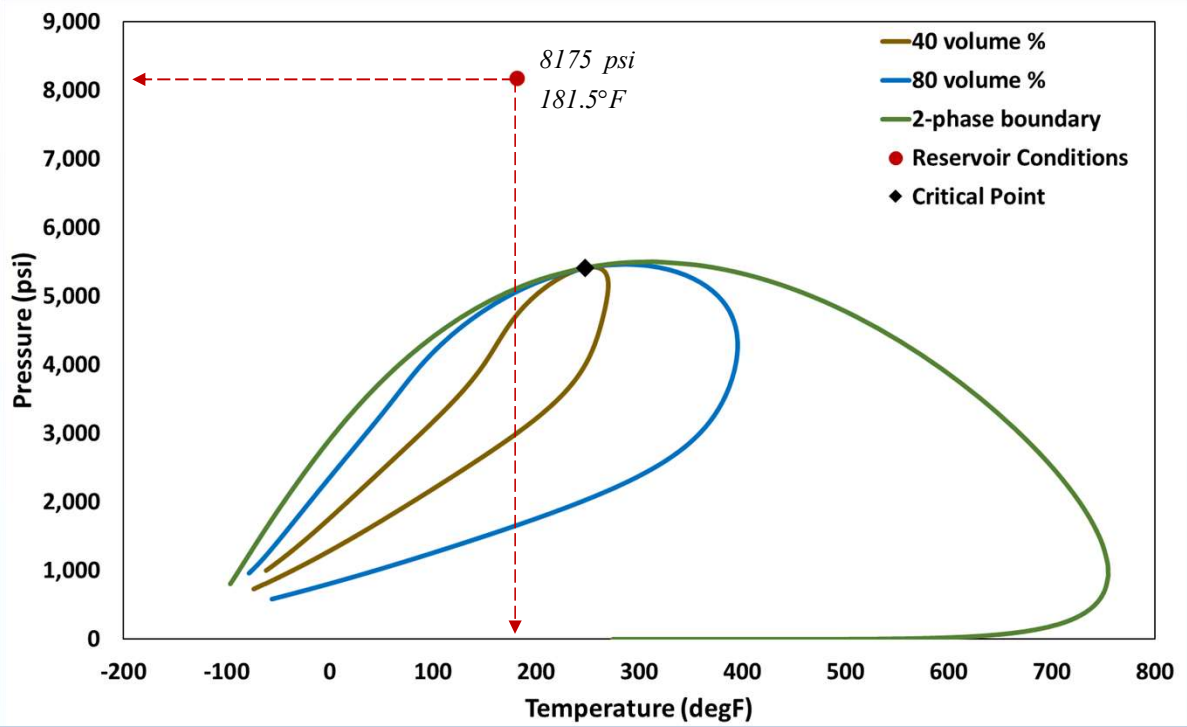
Property	Value	Unit
Porosity	0.06	-
Permeability	0.0003	mD
Compressibility	1×10^{-5}	$psia^{-1}$

Natural Fractures

Property	Value	Unit
Porosity	0.1	-
Effective permeability	0.01	mD
Compressibility	1×10^{-5}	$psia^{-1}$

Property	Value	Unit
L_x	1	ft
L_y	1	ft
L_z	1	ft
σ	12	ft^{-2}

Hydrocarbon Fluid Model



Component	Mole Percent
N_2 to CO_2	0.9
CH_4	67.59
C_2H_6	9.24
C_3H_8	5.51
IC_4 - NC_4	2.79
IC_5 - FC_6	2.31
FC_7 - FC_{10}	5.62
FC_{11} - C_{15}	2.98
FC_{16} - C_{22}	1.69
FC_{23} - C_{30+}	1.35

Initial Numerical Model Input

Matrix

Property	Value	Unit
Initial reservoir pressure	8175	psi
Initial water saturation	0.58	-
Global composition, CH_4	67.59	Mole %
Global composition, C_2H_6	9.24	Mole %
Global composition, C_3H_8	5.51	Mole %
Global composition, IC_4 - NC_4	2.79	Mole %
Global composition, IC_5 - FC_6	2.31	Mole %
Global composition, FC_7 - FC_{10}	5.62	Mole %
Global composition, FC_{11} - C_{15}	2.98	Mole %
Global composition, FC_{16} - C_{22}	1.69	Mole %
Global composition, FC_{23} - C_{30+}	1.35	Mole %

Natural Fractures

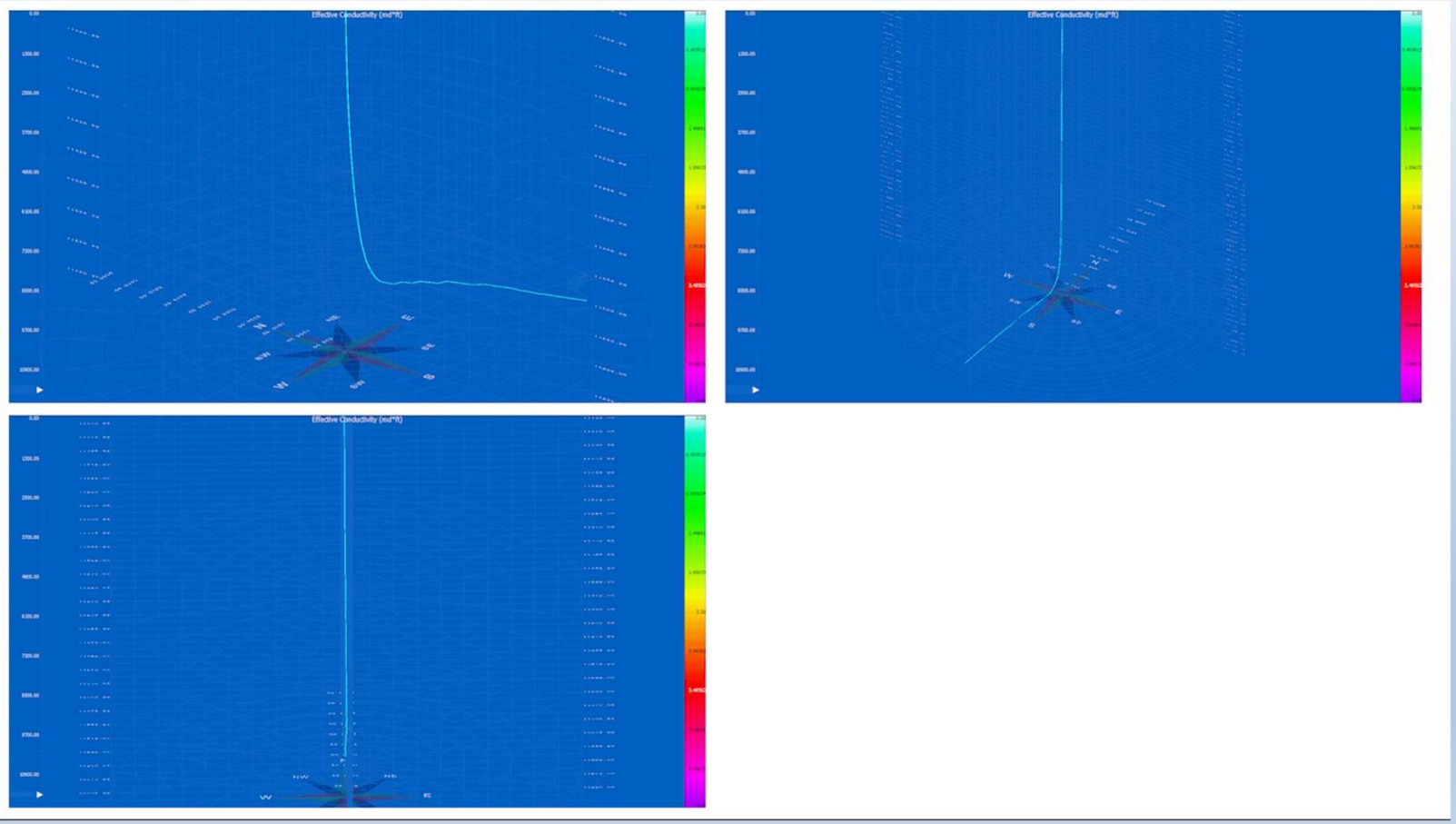
Property	Value	Unit
Initial reservoir pressure	8175	psi
Initial water saturation	0.58	-
Global composition, CH_4	67.59	Mole %
Global composition, C_2H_6	9.24	Mole %
Global composition, C_3H_8	5.51	Mole %
Global composition, IC_4 - NC_4	2.79	Mole %
Global composition, IC_5 - FC_6	2.31	Mole %
Global composition, FC_7 - FC_{10}	5.62	Mole %
Global composition, FC_{11} - C_{15}	2.98	Mole %
Global composition, FC_{16} - C_{22}	1.69	Mole %
Global composition, FC_{23} - C_{30+}	1.35	Mole %

GOHFER Hydraulic Fracture Model Data

STIMULATION TREATMENT INFORMATION

Number of Stages	27
Cluster per stage	4
Stage Length (ft)	212
Cluster Spacing (ft)	52
Total Perforation shot per stage	24
Perforation Diameter (in)	0.54/0.46
Total Fluid per stage (bbls)	8,300
Total proppant volume per stage (lbs)	283,977

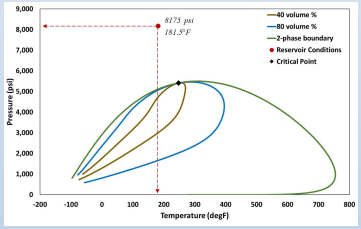
GOHFER Hydraulic Fracture Model

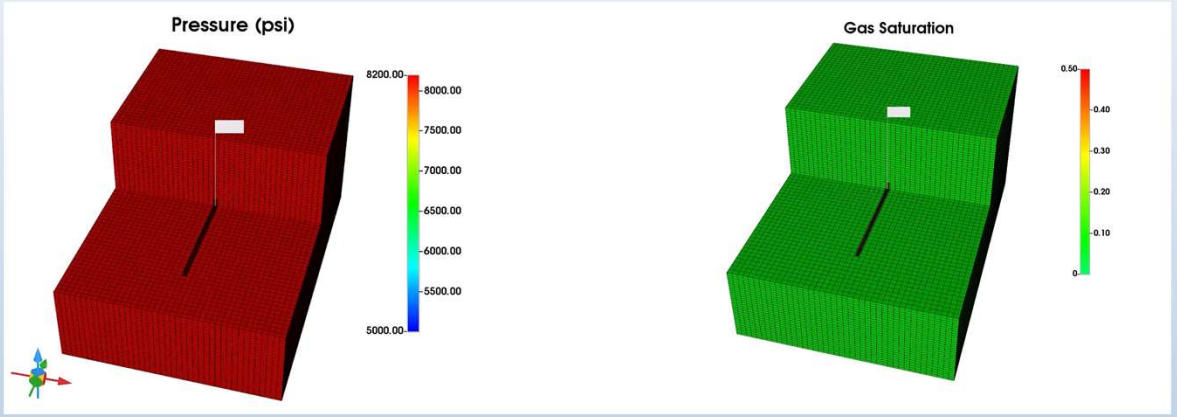


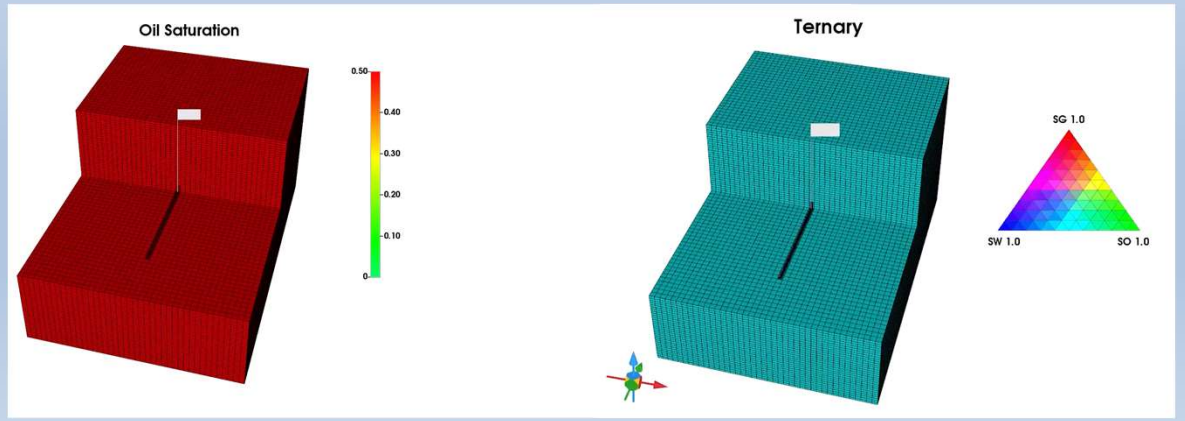
GOHFER Hydraulic Fracture Model Results

INPUT PARAMETERS	Number of Stages	27
	Cluster per stage	4
	Stage Length (ft)	212
	Cluster Spacing (ft)	52
	Total Perforation shot per stage	24
	Perforation Diameter (in)	0.54/0.46
OUTPUT PARAMETERS	Average Proppant Concentration (lb/ft^2)	0.24
	Average Fracture Width (in)	0.32
	Proppant Cutoff Length (ft)	350.34
	Estimated Flowing Fracture Length (ft)	27.34
	Fracture Height (ft)	48.41
	Average Effective Conductivity (mD.ft)	0.78

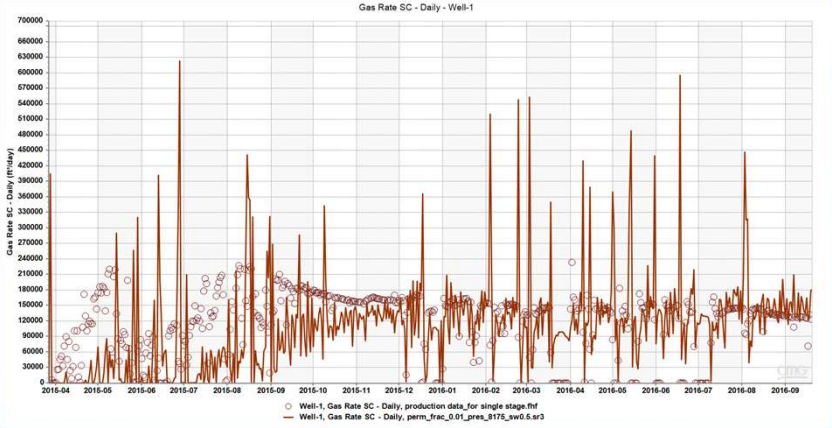
CMG Model (GEM) History Match Results

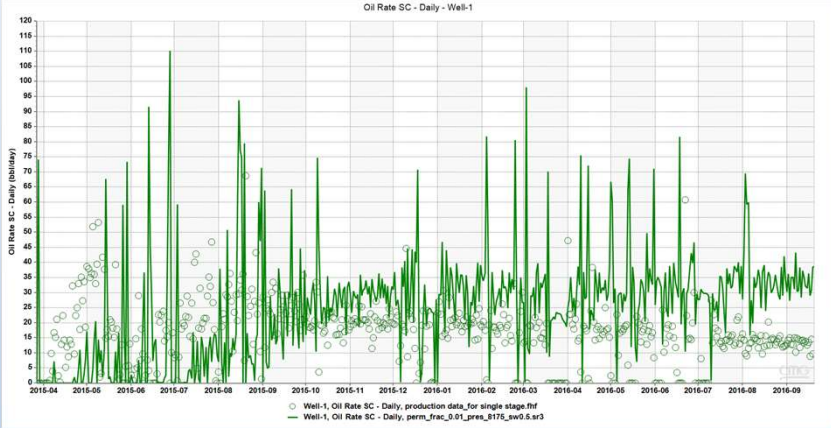


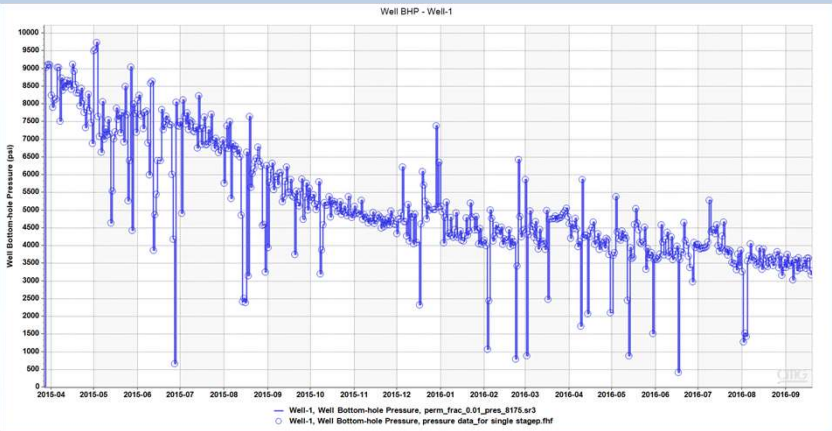




CMG Model History Match Results





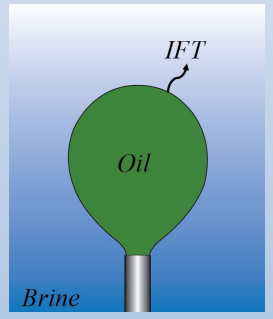


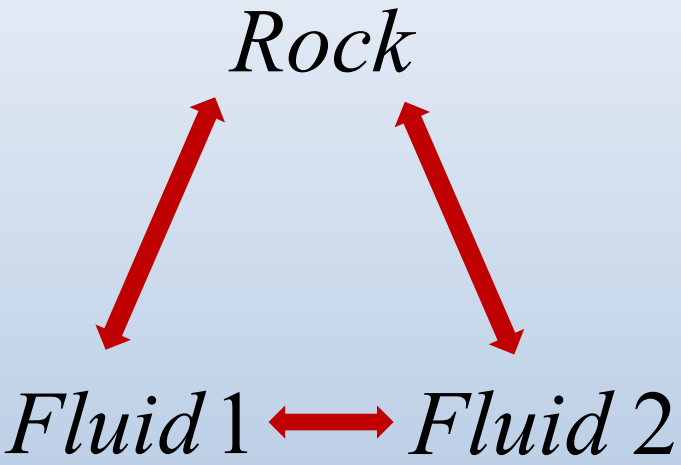
Relative Permeability and Capillary Pressure experiments are required to tune the history matching

Fluid-Rock Interactions

Fluid-Fluid Interactions

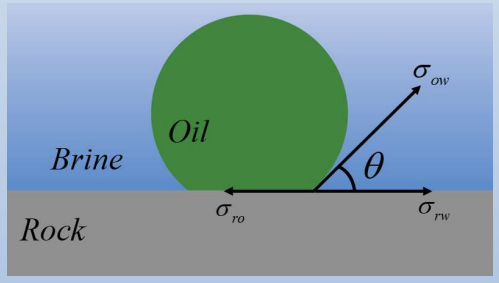
IFT: The force of attraction between the molecules at the interface of two fluids.

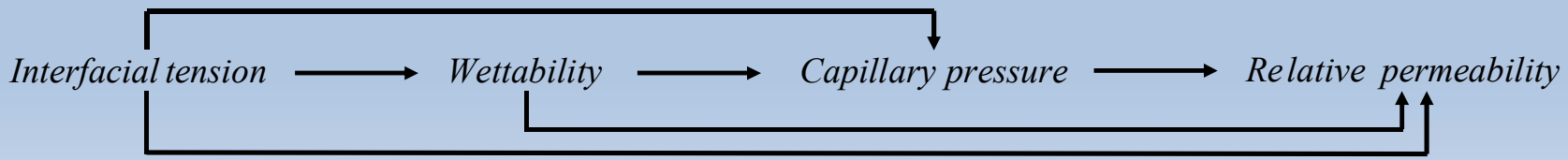




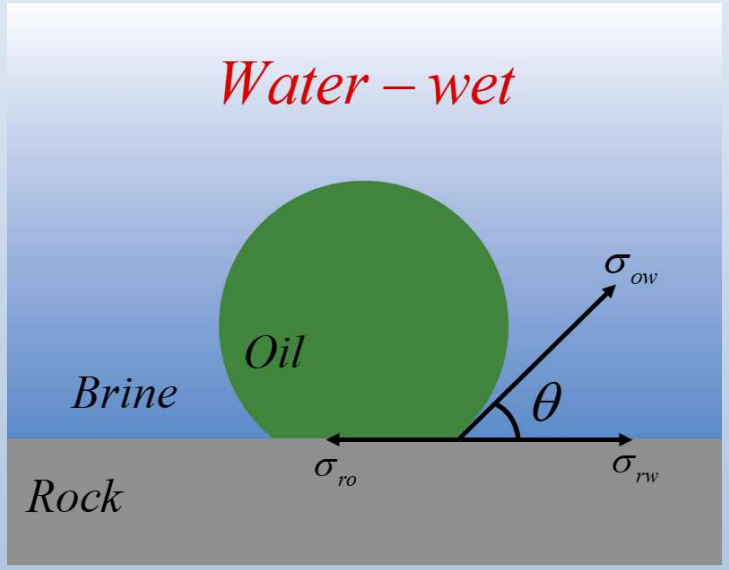
Fluid-Rock Interactions

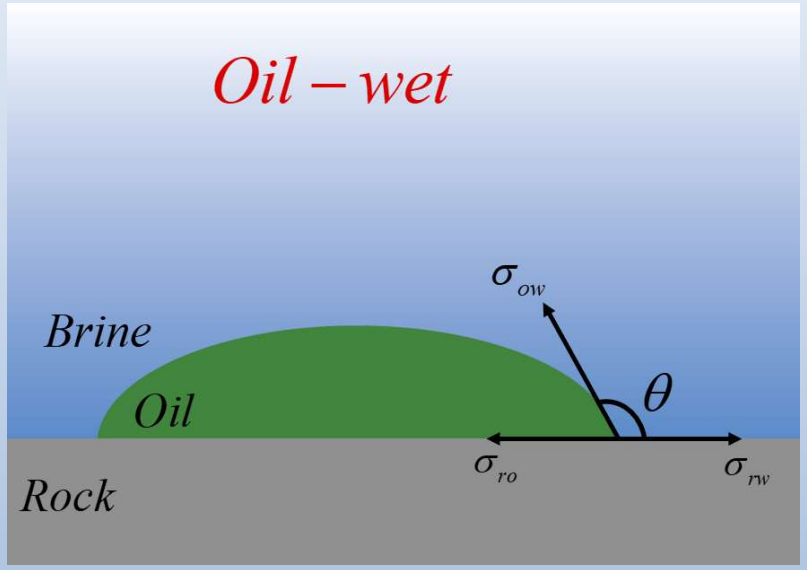
Wettability: Tendency of a fluid to spread on (or adhere to) a solid surface in the presence of another immiscible fluid.





Wettability Concept

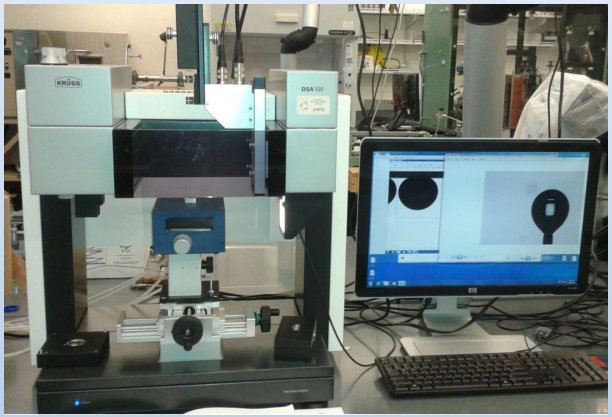




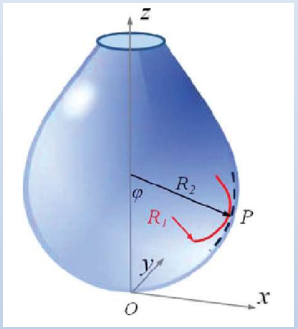
$\sigma_{ro} = IFT\ between$
$rock\ and\ oil\ (dynes / cm)$
$\sigma_{rw} = IFT\ between$
$rock\ and\ brine\ (dynes / cm)$
$\sigma_{ow} = IFT\ between$
$oil\ and\ brine\ (dynes / cm)$

$$\theta > 90 \Rightarrow Oil - wet$$
$$\theta < 90 \Rightarrow Water - wet$$
$$\theta = 90 \Rightarrow Intermediate - wet$$

Drop Shape Analyzer (DSA-100)



Pendant drop method (IFT)



(Yakshi-Tafti et al. 2011)

$$\sigma\left(\frac{1}{R_1}+\frac{1}{R_2}\right)=\Delta p=\Delta\rho gz+C$$

$$\frac{1}{R_1}+\frac{\sin\varphi}{x}=\frac{\Delta\rho gz}{\sigma}+\frac{2}{b}$$

where;

$\sigma = IFT\ (N/m)$

R_1 & R_2 = *principal radii of curvaturelar to* R_1

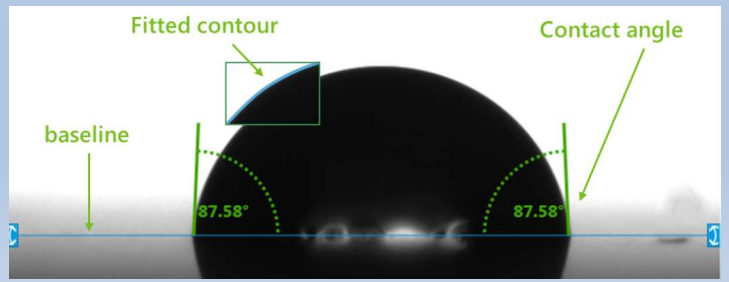
$\Delta p = differential\ pressure\ (N/m^2)$

$\rho = density\ (kg/m^3)$

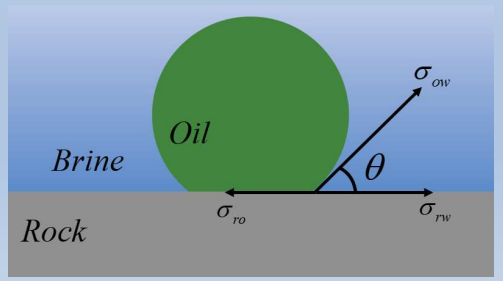
$g = graviatational\ acceleration\ (9.8\,m^2/\sec)$

$\varphi = angle\ between\ R_1\ and\ z-axis$

Captive droplet method (Wettability)



(KRÜSS 2016)



$$\sigma_{ro}=\sigma_{rw}+\sigma_{ow}\cos\theta$$

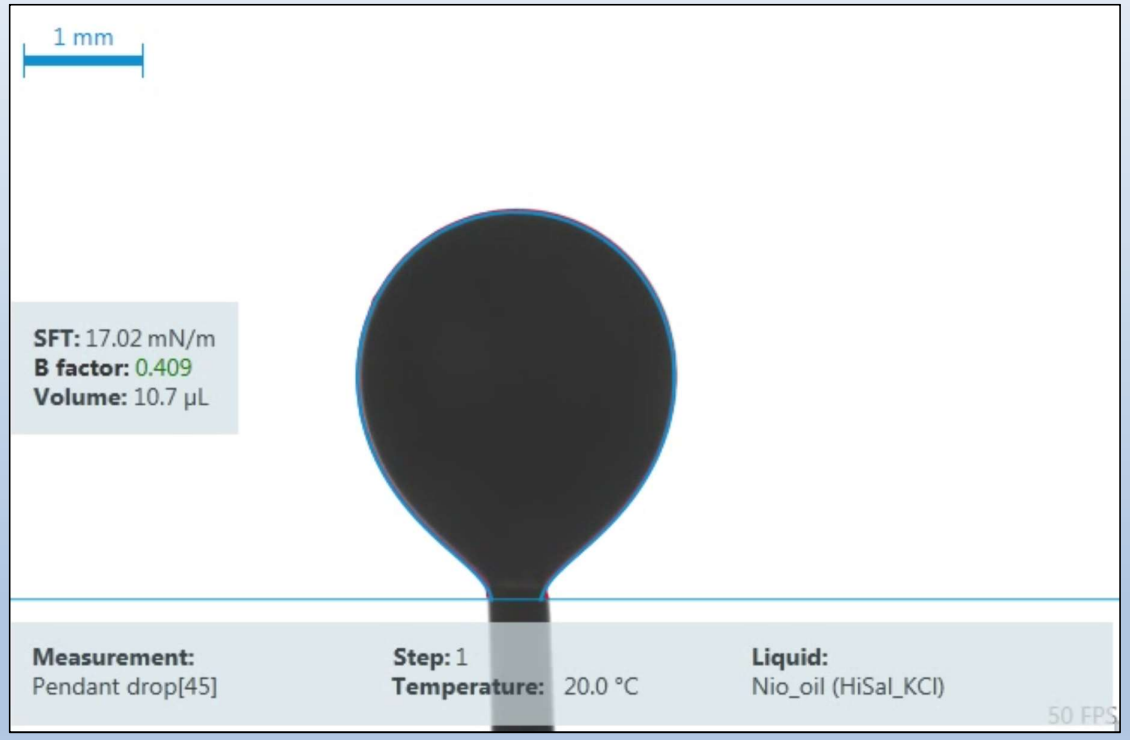
where;

σ_{ro} = *IFT between rock and oil* $(dynes/cm)$

σ_{rw} = *IFT between rock and brine* $(dynes/cm)$

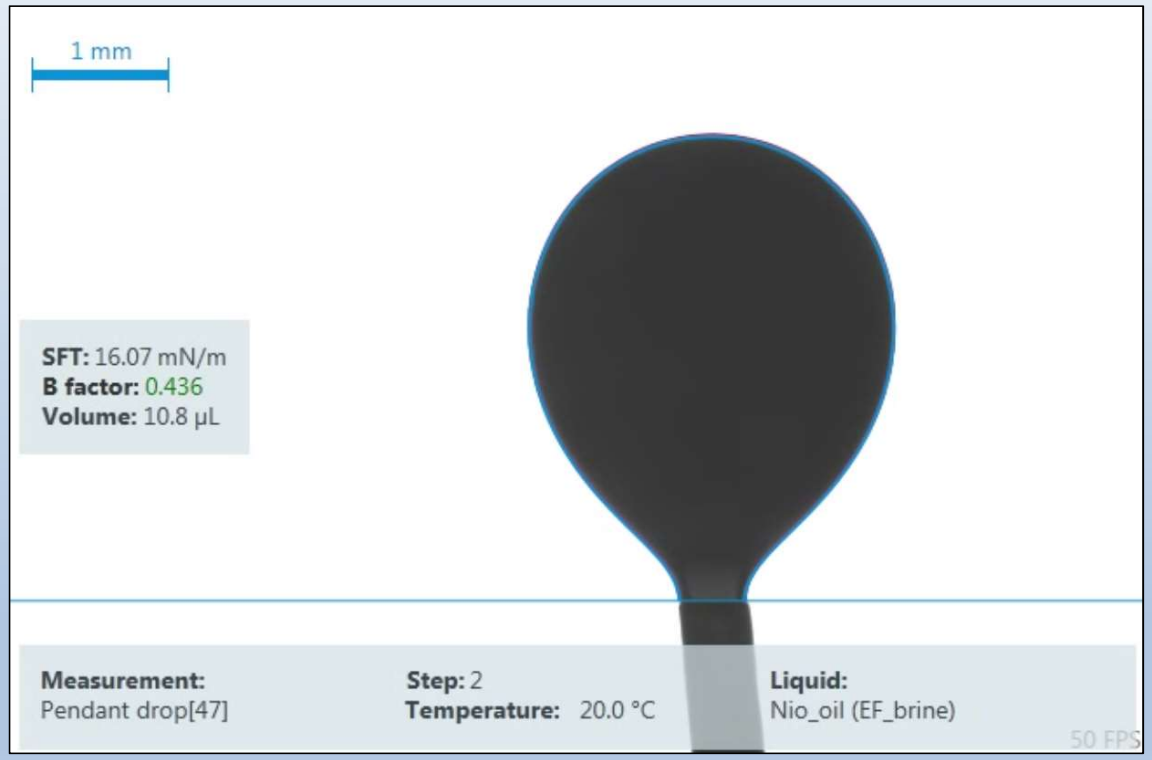
σ_{ow} = *IFT between oil and brine* $(dynes/cm)$

IFT Measurements - Niobrara



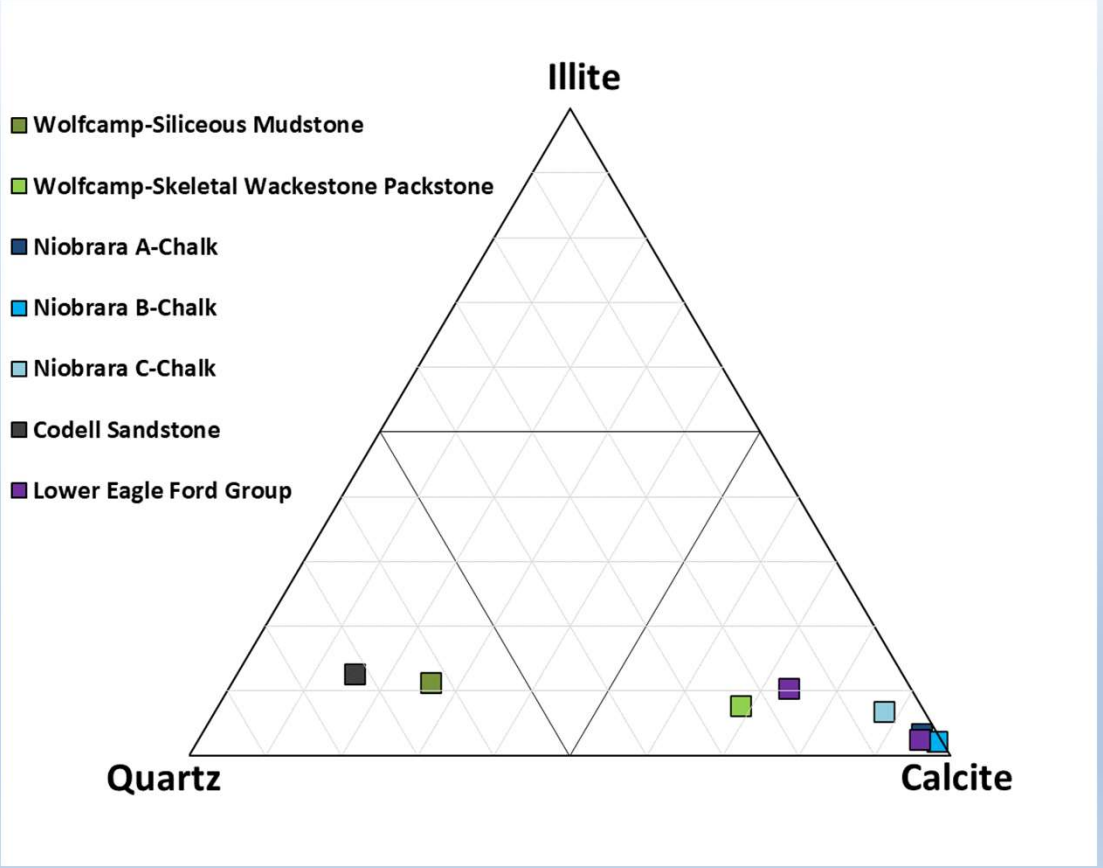
Parameters	
Formation Brine Salinity (ppm)	40,000
Formation Brine Density (g/cc)	1.0406
Oil Density (g/cc)	0.8364
Oil Viscosity (cP at 20^{o}C)	8.13
IFT (dynes/cm)	17.02

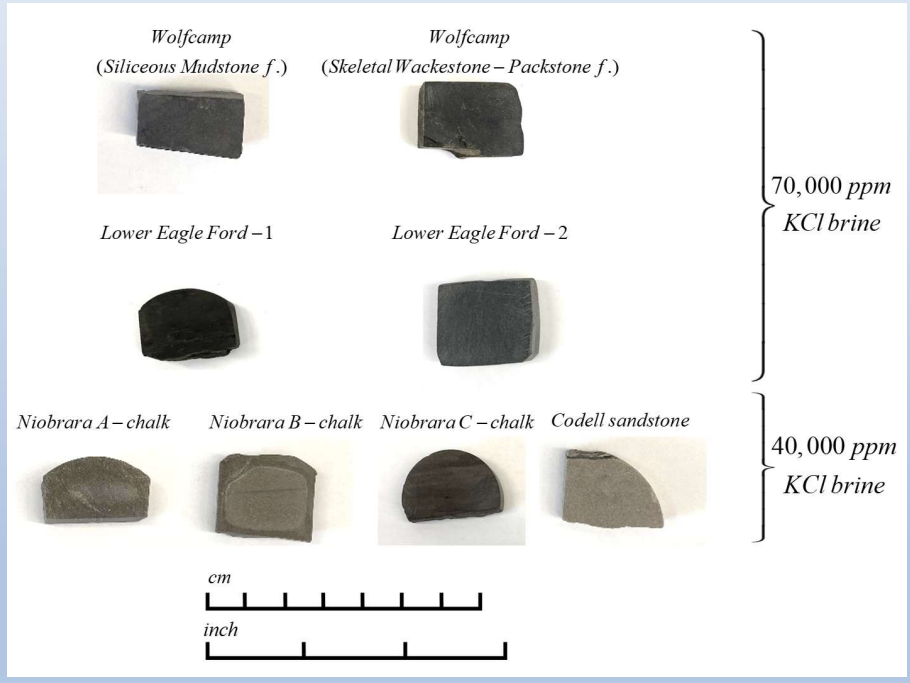
IFT Measurements – Eagle Ford & Wolfcamp



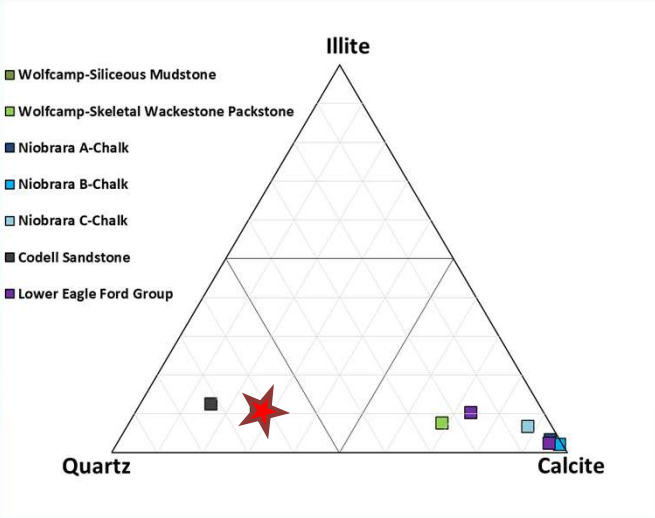
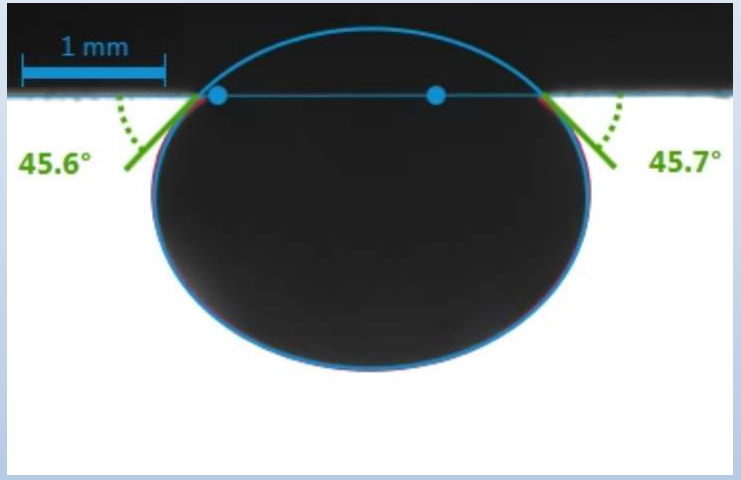
Parameters	
Formation Brine Salinity (ppm)	70,000
Formation Brine Density (g/cc)	1.0566
Oil Density (g/cc)	0.8364
Oil Viscosity (cP at 20^{o}C)	8.13
IFT (dynes/cm)	16.07

Samples

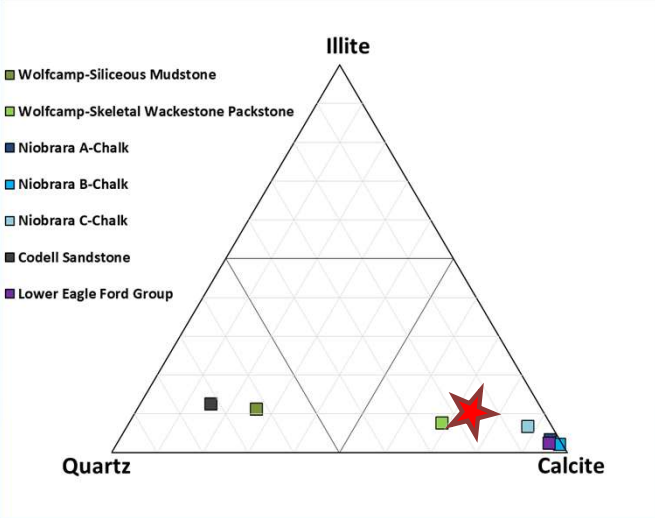
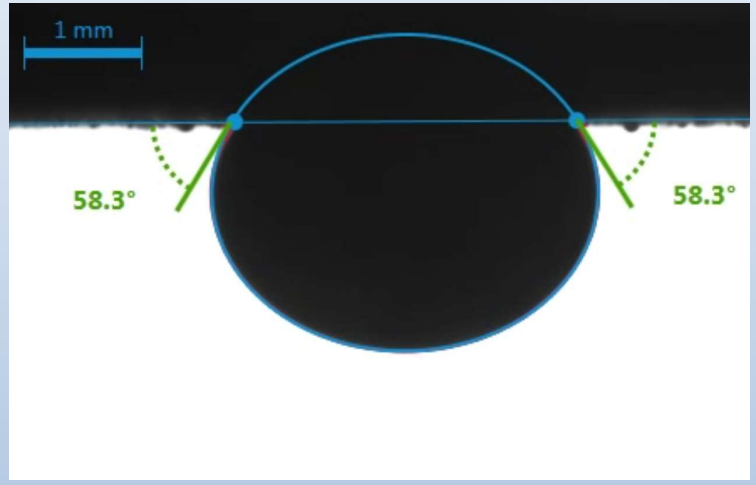

Illite
Wolfcamp-Siliceous Mudstone
Wolfcamp-Skeletal Wackestone Packstone
Niobrara A-Chalk
Niobrara B-Chalk
Niobrara C-Chalk
Codell Sandstone
Lower Eagle Ford Group
Quartz
Calcite


Wolfcamp
(Siliceous Mudstone f.)
Wolfcamp
(Skeletal Wackestone – Packstone f.)
70,000 ppm
KCl brine
Lower Eagle Ford – 1
Lower Eagle Ford – 2
Niobrara A – chalk
Niobrara B – chalk
Niobrara C – chalk
Codell sandstone
40,000 ppm
KCl brine
cm
inch

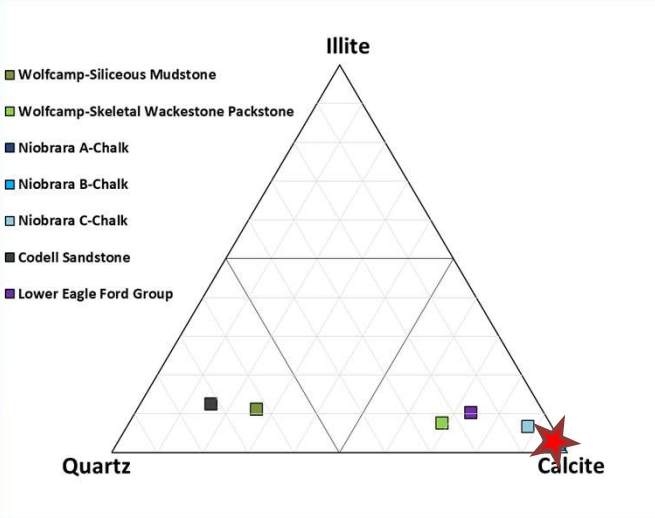
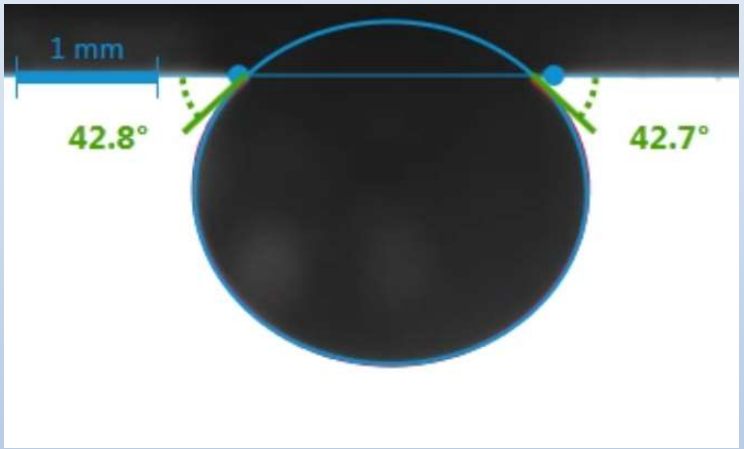
Contact Angle Measurements

Wolfcamp A – Siliceous Mudstone	Parameters		Contact Angle
	Porosity (%)	NA	
	Permeability (mD)	NA	
	Formation Brine Salinity (ppm)	70,000	
	Formation Brine Density (g/cc)	1.0566	
	Oil Density (g/cc)	0.8634	
			**45.6°**

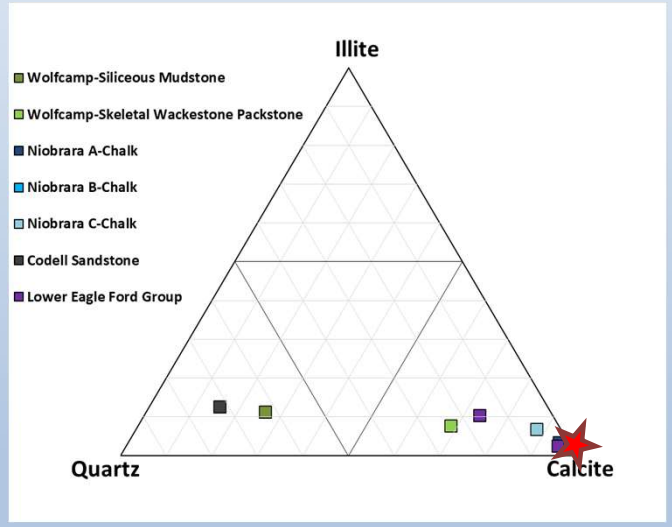
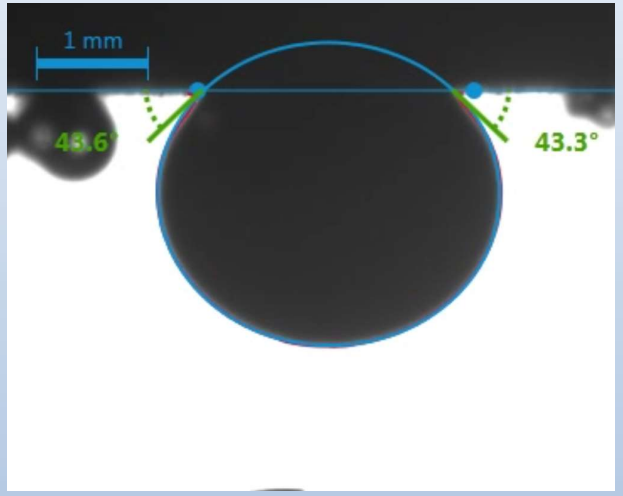
Contact Angle Measurements

Wolfcamp A – Skeletal Wackestone	Parameters		Contact Angle
	Porosity (%)	NA	
	Permeability (mD)	NA	
	Formation Brine Salinity (ppm)	70,000	
	Formation Brine Density (g/cc)	1.0566	
	Oil Density (g/cc)	0.8634	
			**58.3°**

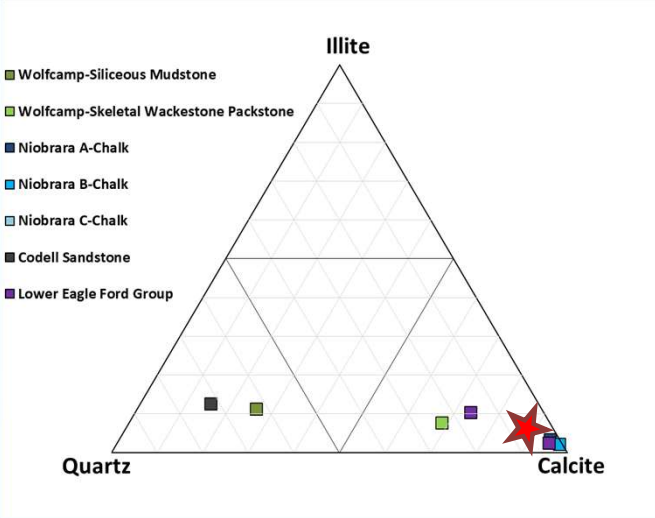
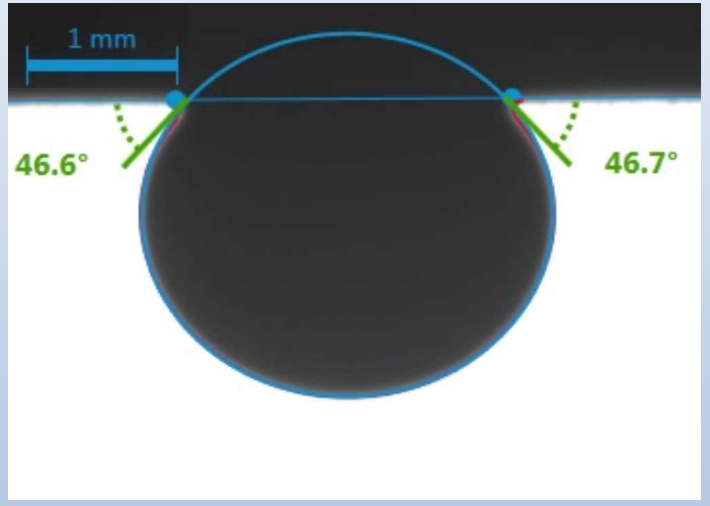
Contact Angle Measurements

Niobrara A-chalk	Parameters		Contact Angle
	Porosity (%)	13.04	
	Permeability (mD)	0.008	
	Formation Brine Salinity (ppm)	40,000	
	Formation Brine Density (g/cc)	1.0406	
	Oil Density (g/cc)	0.8634	
			**42.7°**

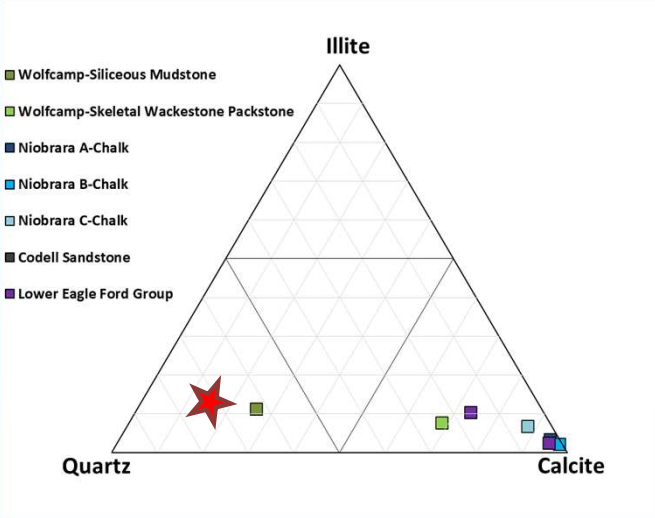
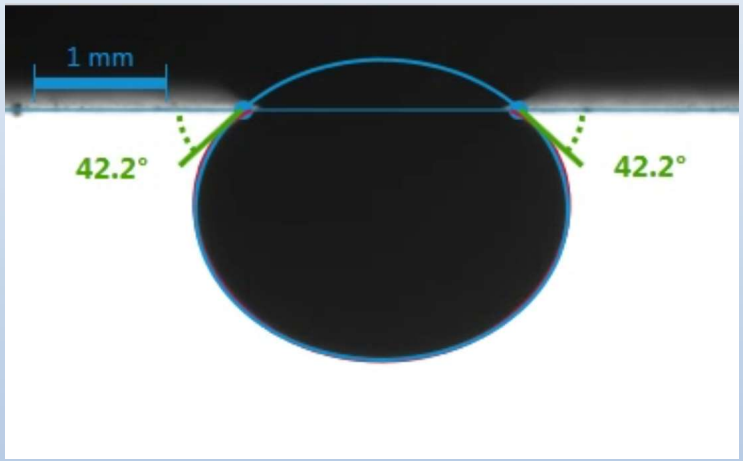
Contact Angle Measurements

Niobrara B-chalk	Parameters		Contact Angle
	Porosity (%)	10.74	
	Permeability (mD)	0.002	
	Formation Brine Salinity (ppm)	40,000	
	Formation Brine Density (g/cc)	1.0406	
	Oil Density (g/cc)	0.8634	**43.3°**
			

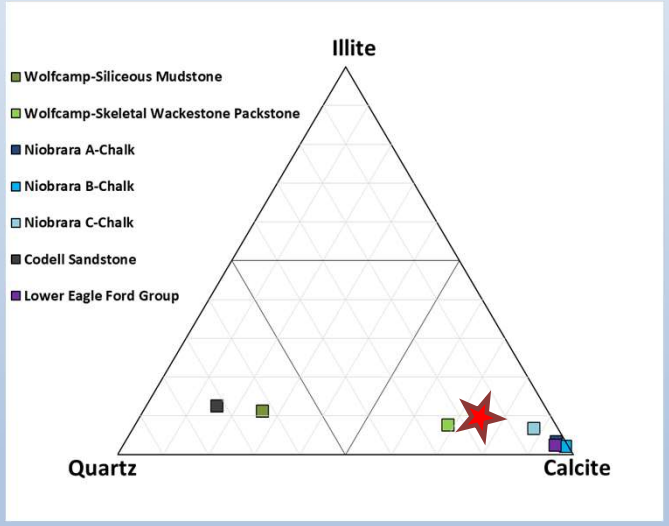
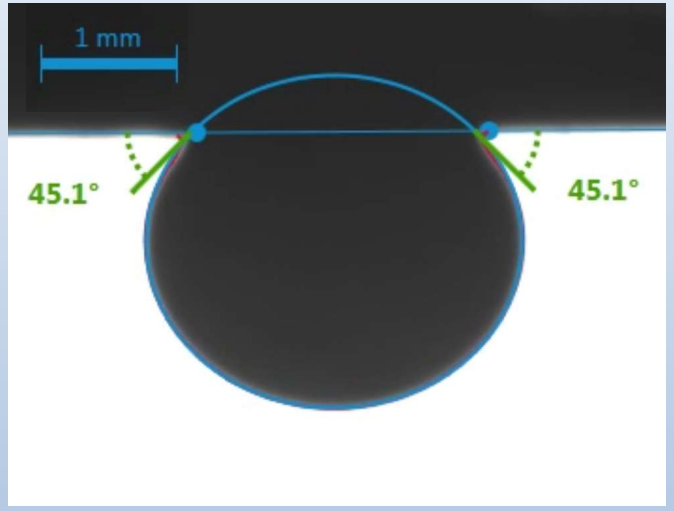
Contact Angle Measurements

Niobrara C-chalk	Parameters		Contact Angle
	Porosity (%)	8.33	
	Permeability (mD)	0.004	
	Formation Brine Salinity (ppm)	40,000	
	Formation Brine Density (g/cc)	1.0406	
	Oil Density (g/cc)	0.8634	
			**46.6°**

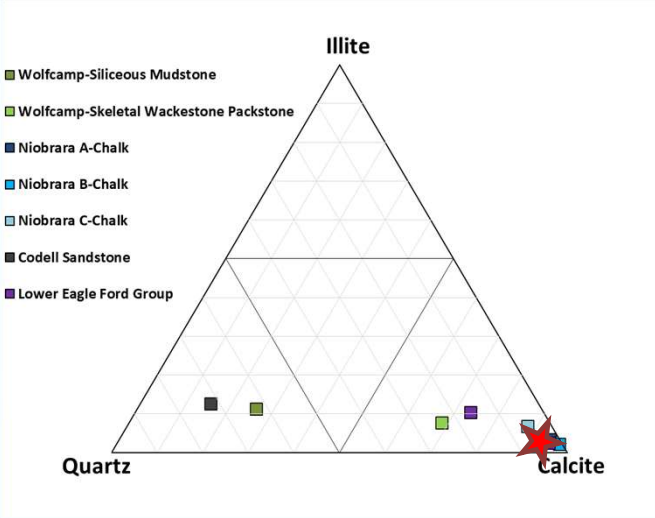
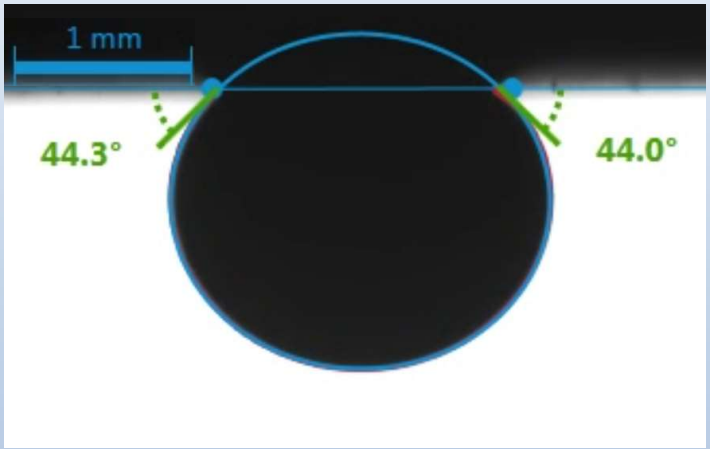
Contact Angle Measurements

Codell Sandstone	Parameters		Contact Angle
	Porosity (%)	14.45	
	Permeability (mD)	0.01	
	Formation Brine Salinity (ppm)	40,000	
	Formation Brine Density (g/cc)	1.0406	
	Oil Density (g/cc)	0.8634	
			**42.2°**

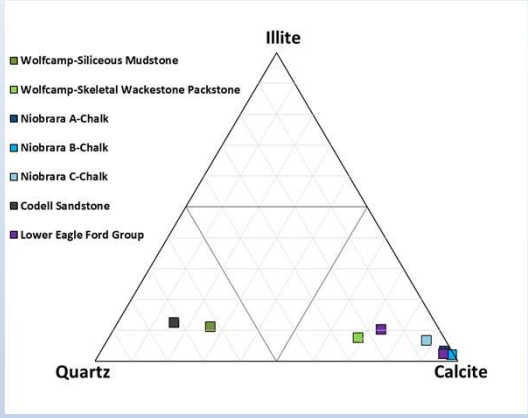
Contact Angle Measurements

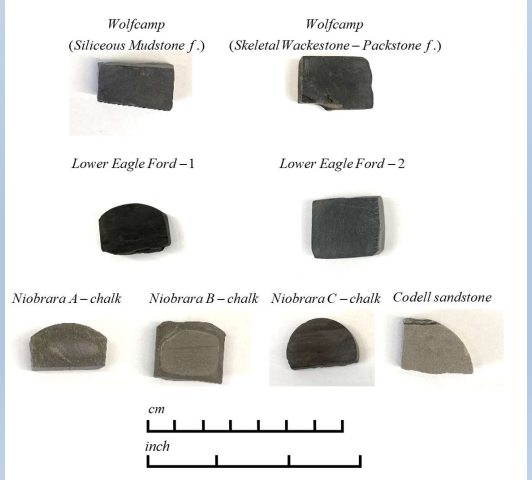
Lower Eagle Ford – 1	Parameters		Contact Angle
	Porosity (%)	6.2	
	Permeability (mD)	0.002	
	Formation Brine Salinity (ppm)	70,000	
	Formation Brine Density (g/cc)	1.0566	
	Oil Density (g/cc)	0.8634	
			**45.1°**

Contact Angle Measurements

Lower Eagle Ford – 2	Parameters		Contact Angle
	Porosity (%)	NA	
	Permeability (mD)	NA	
	Formation Brine Salinity (ppm)	70,000	
	Formation Brine Density (g/cc)	1.0566	
	Oil Density (g/cc)	0.8634	
			**44.0°**

Comparison of Results





Sample	Depth (ft)	Contact Angle
Wolfcamp A – Siliceous Mudstone	9575	45.6
Wolfcamp A – Skeletal Wackestone Packstone	9571.6	58.3
Niobrara A-chalk	5534.95	42.7
Niobrara B-chalk	5605.55	43.3
Niobrara C-chalk	5696.4	46.6
Codell sandstone	5830.75	42.2
Lower Eagle Ford – 1	12100.95	45.1
Lower Eagle Ford – 2	12101.35	44.0

ACKNOWLEDGEMENT

- Dr. Hossein Kazemi (Co-Advisor)
- Dr. Steve Sonnenberg (Co-Advisor)
- Dr. Bob Barree and GOHFER Development Team
- Kathy & Jim Emme
- Emre Cankut Kondakci (XRF)

MUDTOC Consortium Sponsors
Fall 2021

Colorado School of Mines MUDTOC

Sponsoring Member Companies

Anschutz Exploration Corporation

Antero Resources

Bonanza Creek

Chevron

Cimarex

Crestone Peak Resources

devon

Enverus

EOG Resources

GMT Exploration Company LLC

OXY

Red Willow Production Company

Shell

TGS

White Eagle Exploration

Whiting

In-Kind Supporting Companies

GeoMark

IHS

Mike Johnson & Associates

MJ Logs

PRA Platte River Associates, Inc.

Schlumberger

Stratum Reservoir