Understanding Water Partitioning Between Shale Matrix and Fractures to Improve Water Use and Gas Production

FWP-FP00008256 (ESD14085)

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Fundamental Shale Research Project Review Meeting

October 16, 2020

U.S. DEPARTMENT OF ENERGY | Fossil Energy
OFFICE OF OIL & NATURAL GAS

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Problems of water use in hydraulic fracturing

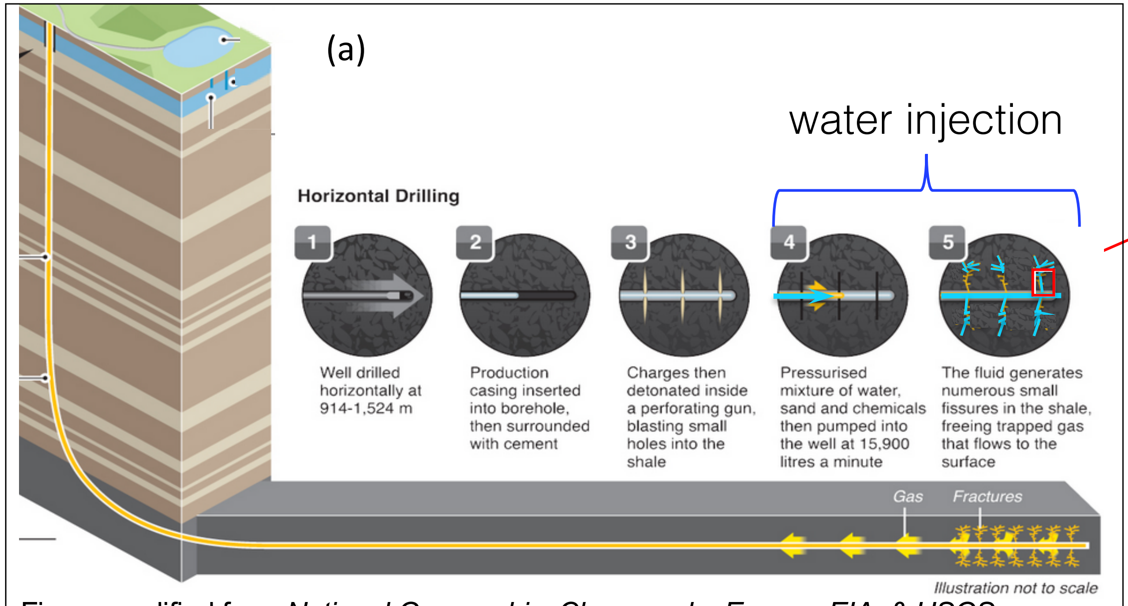
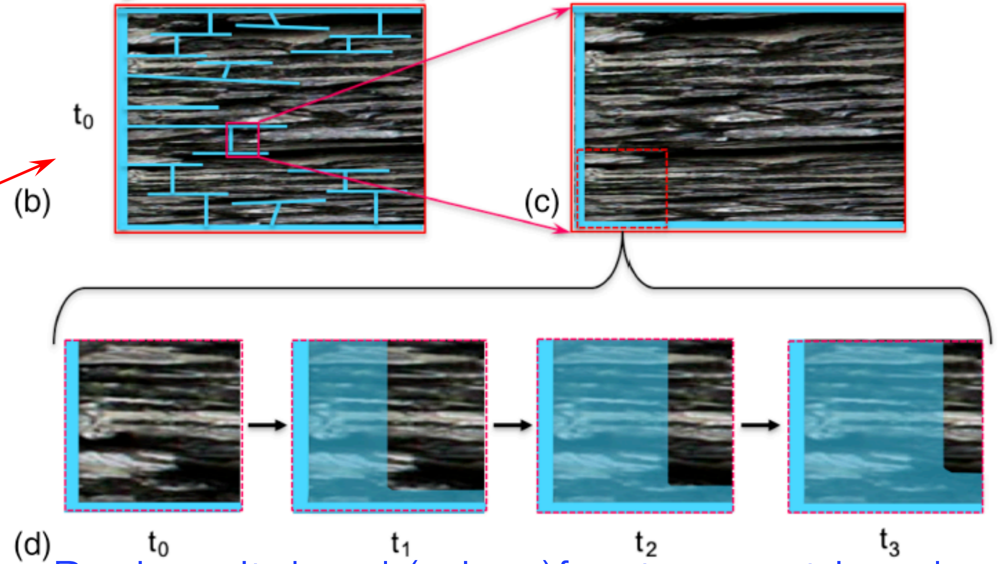


Figure modified from *National Geographic, Chesapeake Energy, EIA, & USGS*



Basic unit: local (micro)fracture-matrix volumes

- 10^6 to 10^7 gallons of water is used per well to hydraulically fracture shale reservoirs.
- Cost of water supply and flow-back water treatment are large ($50K to $1M per well).
- Typically > 70% of injected water remains in the reservoir matrix pores and restricts counter-current flow of gas back to wells.
- A rational basis for reducing water use can be very beneficial.

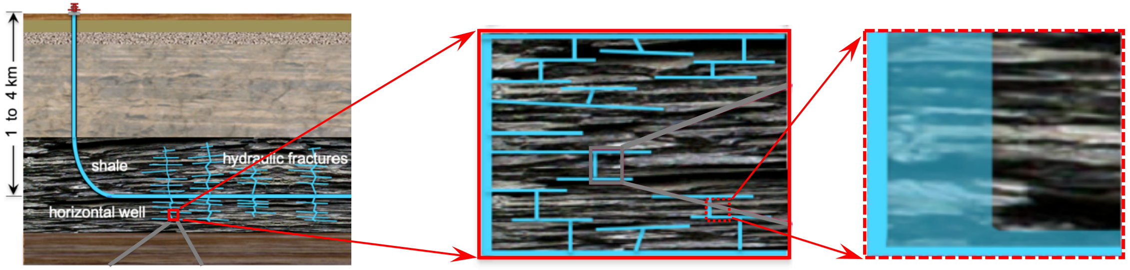
Research Challenges

- Transport properties controlling water and gas distributions are spatially variable, and fracture connectivity is complex.
- Actual distributions of matrix and fracture permeabilities will never be known.
- Improved, physically-based, practical models are needed to optimize water use for efficient hydrocarbon recovery.

Goals and Objectives

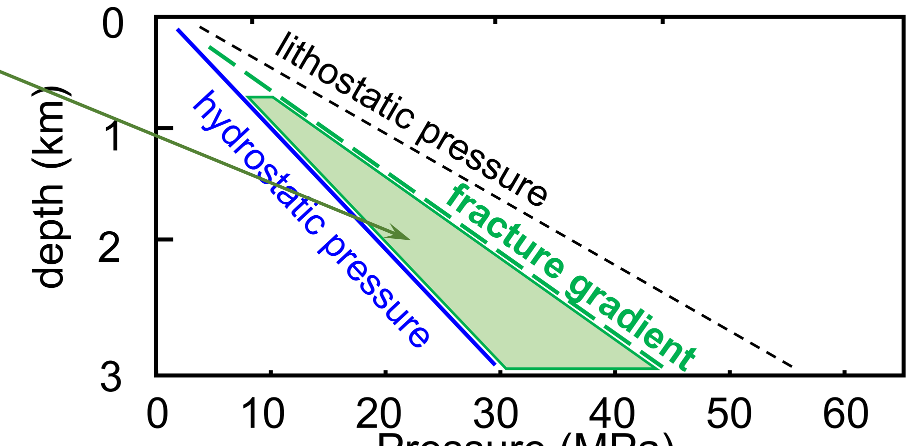
- Improve understanding and predictions of water entry and redistribution in low permeability materials
- Identify the hierarchy of factors controlling water blocking
- Improve simple models of water-gas transport in unconventional reservoirs
- Understand impacts of varying water injection volumes and shut-in times on production

Pressure, viscosity, permeability, and time determine leak-off rates



Fracturing fluid pressure at the fracture-matrix interface, $-P_{c,0}$, is constrained between the depth-dependent frac P and hydrostatic P.

- $|P_{c,0}|$ at fracture-matrix interfaces in reservoirs are huge. At 2 km depth, shut-in $P_{c,0} \approx$ -30 MPa.



modified from:
http://www.glossary.oilfield.slb.com/en/Terms.aspx?LookIn=term%20name&filter=pressure%20gradient

Under these conditions, the imbibition volume per unit area ***I(t)*** and the wetting front distance *L(t)* are

$$I(t) = \left[\sqrt{\frac{0.182n|P_{c,0}/P_{c,f}|}{\mu}}\,k^{0.32}\right]\sqrt{t}$$

sorptivity S

$$L(t) = \sqrt{\frac{0.182|P_{c,0}/P_{c,f}|}{n\mu}}\,k^{0.32}\sqrt{t}$$

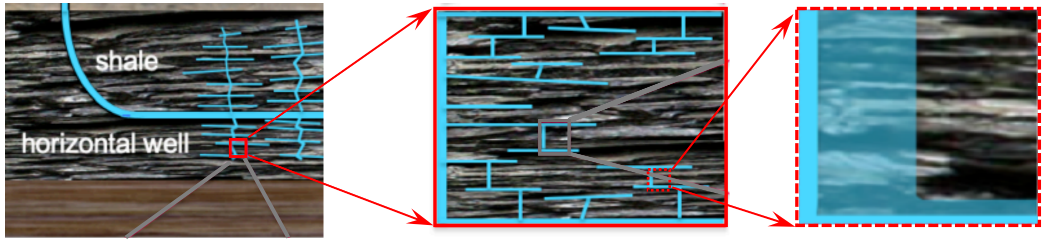
Tokunaga, Water Resour. Res., 2020

where n is the shale porosity, μ is the fluid viscosity, $P_{c,f}$ is the wetting front capillary pressure, k is the shale permeability, and t is time.

- Under reservoir stimulation conditions, influences of capillary pressure at the wetting front (including wettability) on flow are predicted to be of secondary importance because $|P_{c,0}| >> P_{c,f}$.

Water imbibition dependence on permeability and time

Hydraulic fracturing at 2 km depth, predictions for *k*-dependent imbibition and water-block thicknesses.



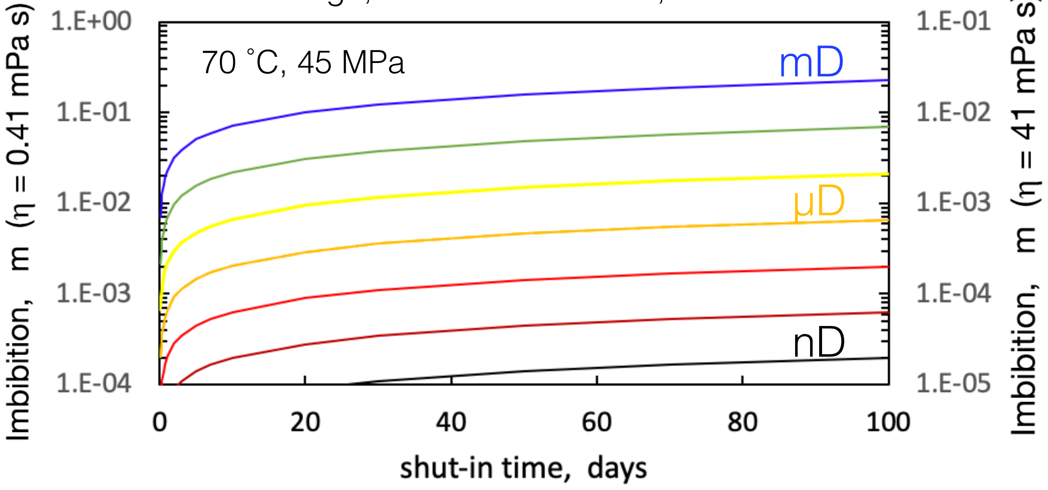
- Water volume/(entry fracture area) is less than 1 cm into low *k* (≤ 1 μDarcy) shale matrix, for shut-in times up to a month.

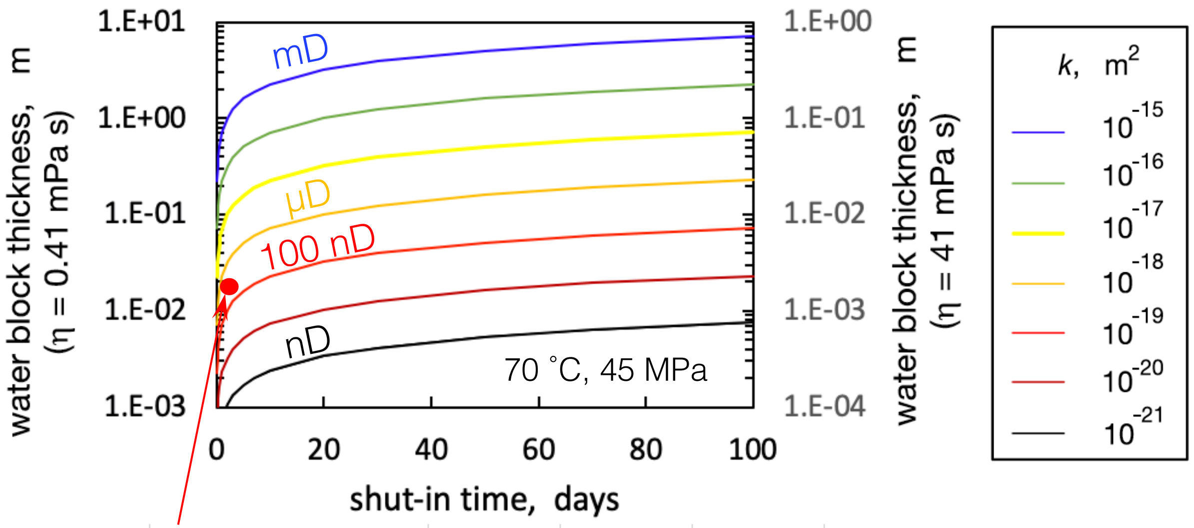
- Water blocks in low *k* (≤ 1 μDarcy) shale are only centimeters thick for shut-in times up to a month, but impede hydrocarbon recovery.

- Fracture-microfracture networks have very large interconnected areas, > 10^6 m^2/well!

- Minimizing shut-in times reduces water block thicknesses and precipitation along fractures, hence can improve production.

Tokunaga, Water Resour. Res., 2020





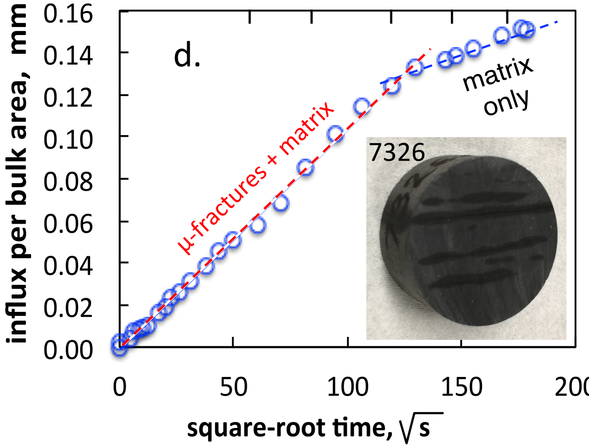
100 nD shale, day 1, at 78 ˚C, 76 MPa, from Moridis, SPE-185512, 2017.

Simple measurements of *sorptivity* can be used to estimate k

Philip (1954), termed the parameter linking cumulative imbibition per unit area to the square-root of time the sorptivity, S .

$$I(t) = \underbrace{\left\{ \sqrt{\frac{0.182n\left[1+\left(|P_{c,0}|/P_{c,f}\right)\right]}{\mu}}\,k^{0.32} \right\}}\sqrt{t}$$

For low magnitude values of $P_{c,0}$, this group of parameters is the sorptivity, S

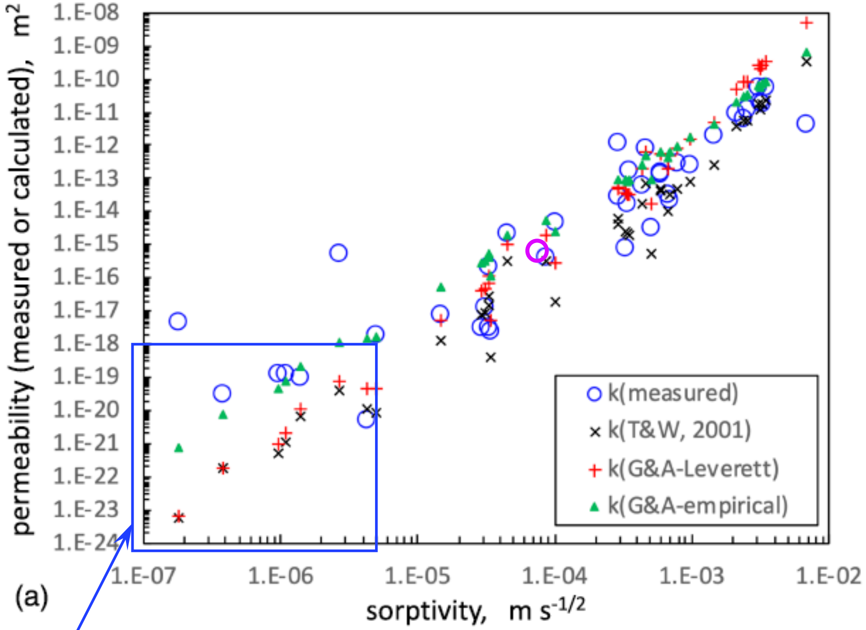


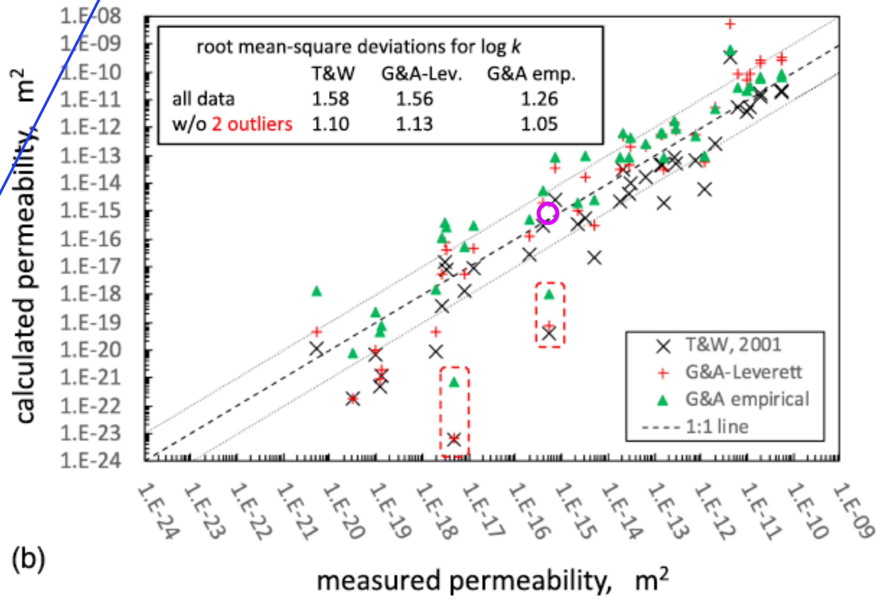
Therefore, simple ambient pressure imbibition measurements can be used to estimate k

$$k \approx \left(\frac{\mu}{2j_2 n}\right)^{1.56} S^{3.12}$$

Although mineralogy and wettability can influence S–k relations, these may be minor influences on imbibition driven by high pressures for fracturing and shut-in.

Currently, there are few reliable measurements of both *k(water) and S* in µD to nD materials.



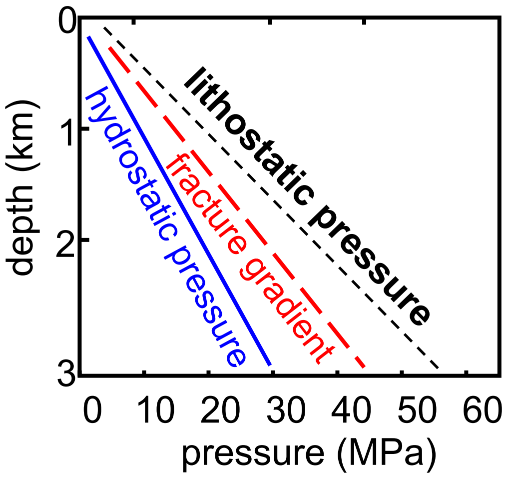


Tokunaga, Water Resour. Res., 2020

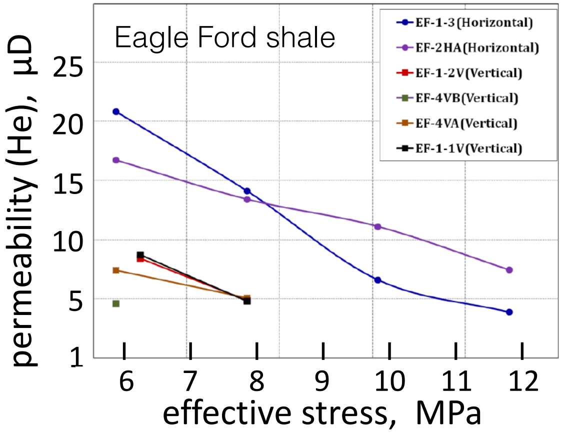
Challenges for Laboratory Water Permeability Measurements on Unconventional Reservoir Samples

- Core samples undergo at least 10 MPa of stress relief upon recovery from wells.
- Cores often experience further visible damage during preparation in laboratory.
- *k* values are stress-dependent.
- Gas flow is commonly used, but Knudsen (Klinkenberg) slip corrections needed to obtain true *k* have significant uncertainty.
- Dry gas flow is insensitive to wettability.
- Very low *k* cores are most susceptible to annular (wall) flow artifacts
- The crushed rock method give highly variable measurements of low *k* (Profice & Lenormand, Petrophys. 2020)
- Crushed rock *k* method destroys the rock matrix, eliminating intergranular flow networks.

stress-release sample damage

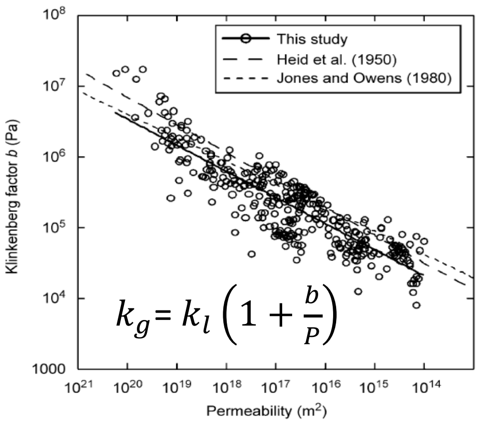


stress-dependence of *k*



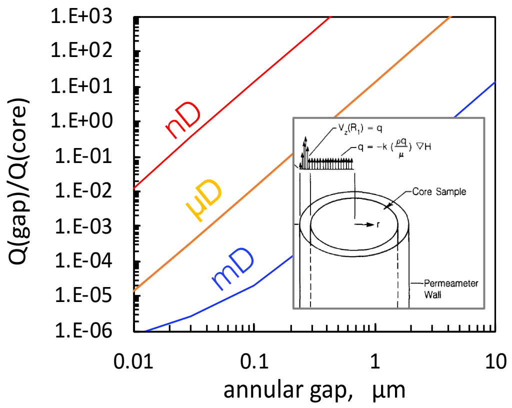
Mokhtari et al., URTeC 1555068, 2013

uncertain gas slip corrections



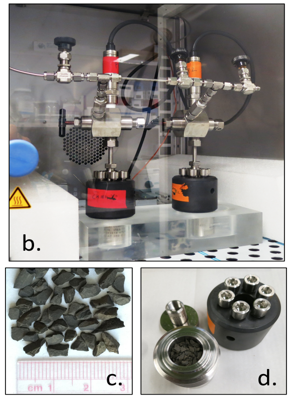
Tanikawa & Shimamoto, Int. J. Rock Mech. Mining Sci. 2009

wall flow errors for very low *k*



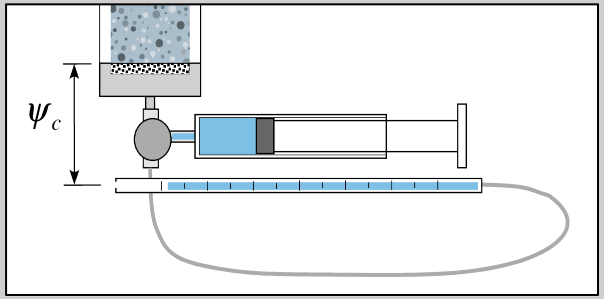
Tokunaga, Soil Sci. Soc. Am. J., 1988

crushed rock method

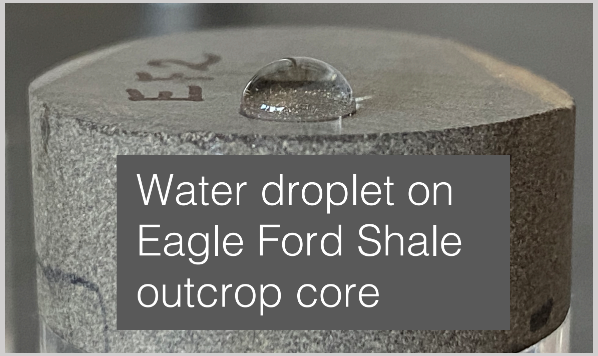


Method for measuring very low *S* and *k* in µD to sub-nD materials is being developed

Beginning measuring very low water flow rates needed to quantify *k*(water)

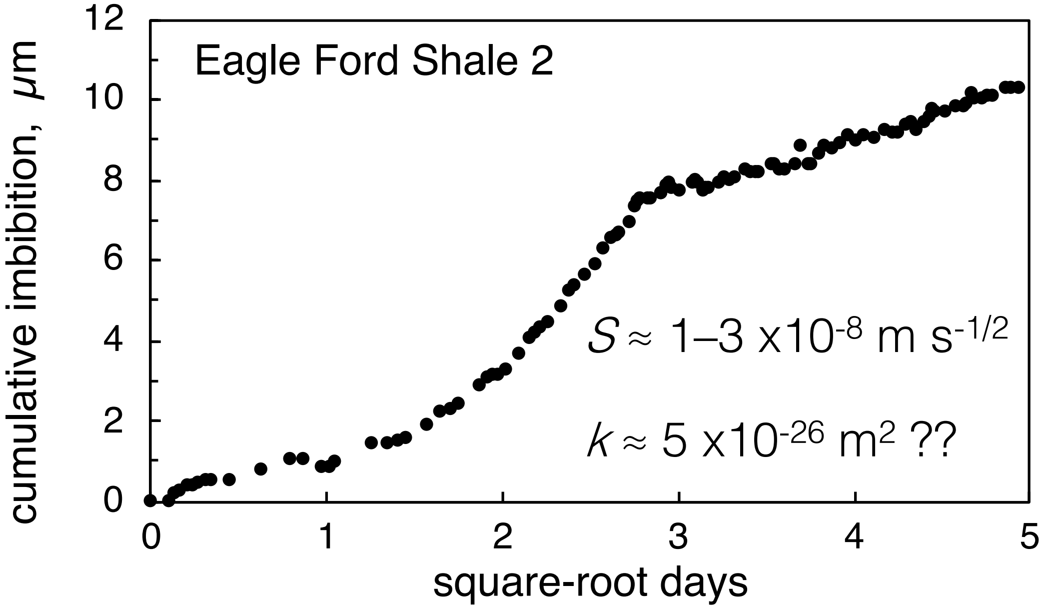


Modifying earlier method for measuring sorptivities at fixed capillary pressure



The wettability influence on water imbibition into shales is important at low pressures.

1. Quantifying very low imbibition rates



2. Encountering anomalous imbibition trends.

3. Directly measuring *S* and *k(water)* on same samples to test *S*-*k* predictions, and examine impacts of wettability.

Experimental Investigation of Spontaneous Imbibition

SI experiment

- Repeated weight measurement as fluid imbibes
- Cumulative imbibed volume per unit flow area (I) is estimated

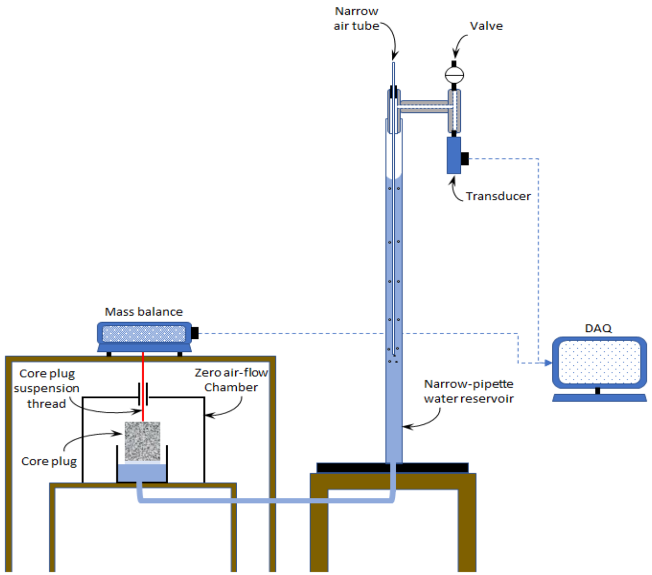
Fluid characterization

- Rheological testing
- IFT measurement

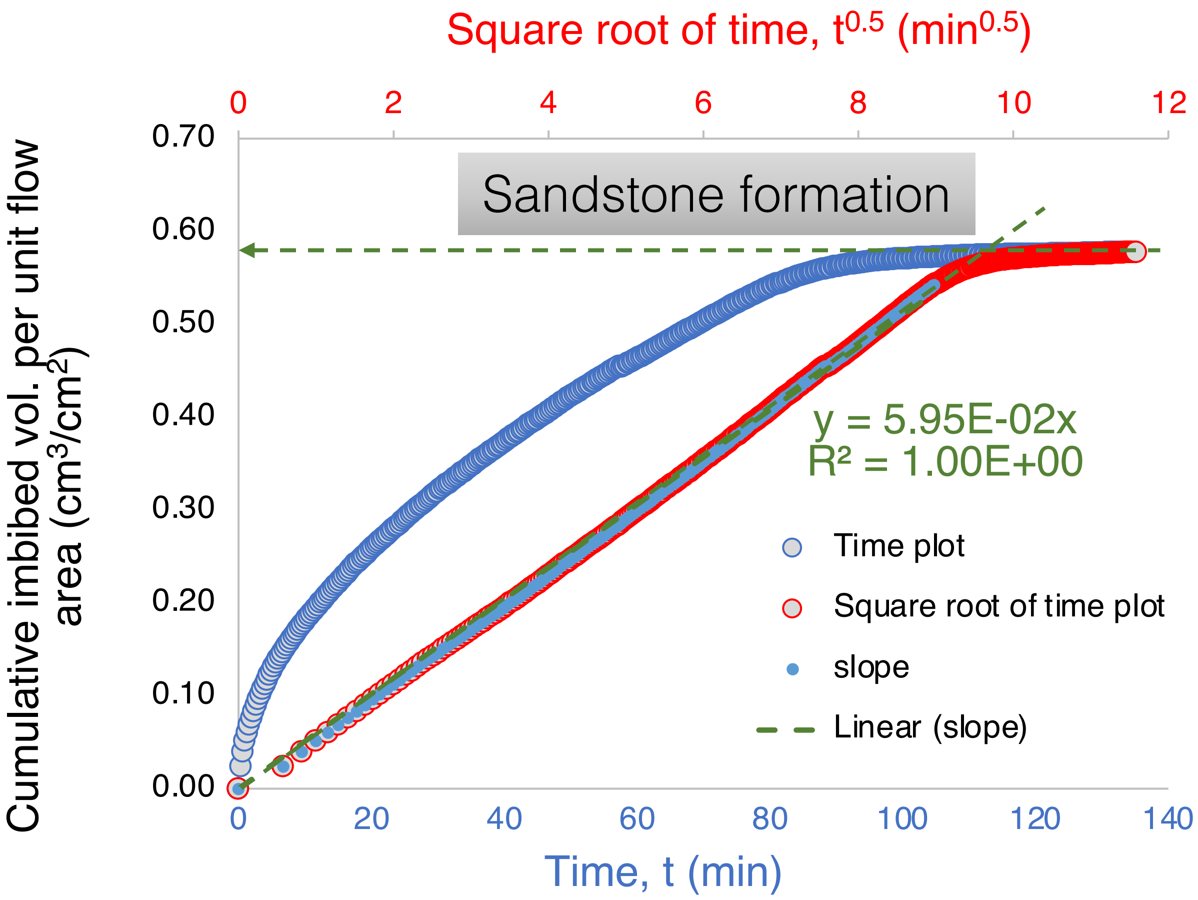
Fluid sample preparation

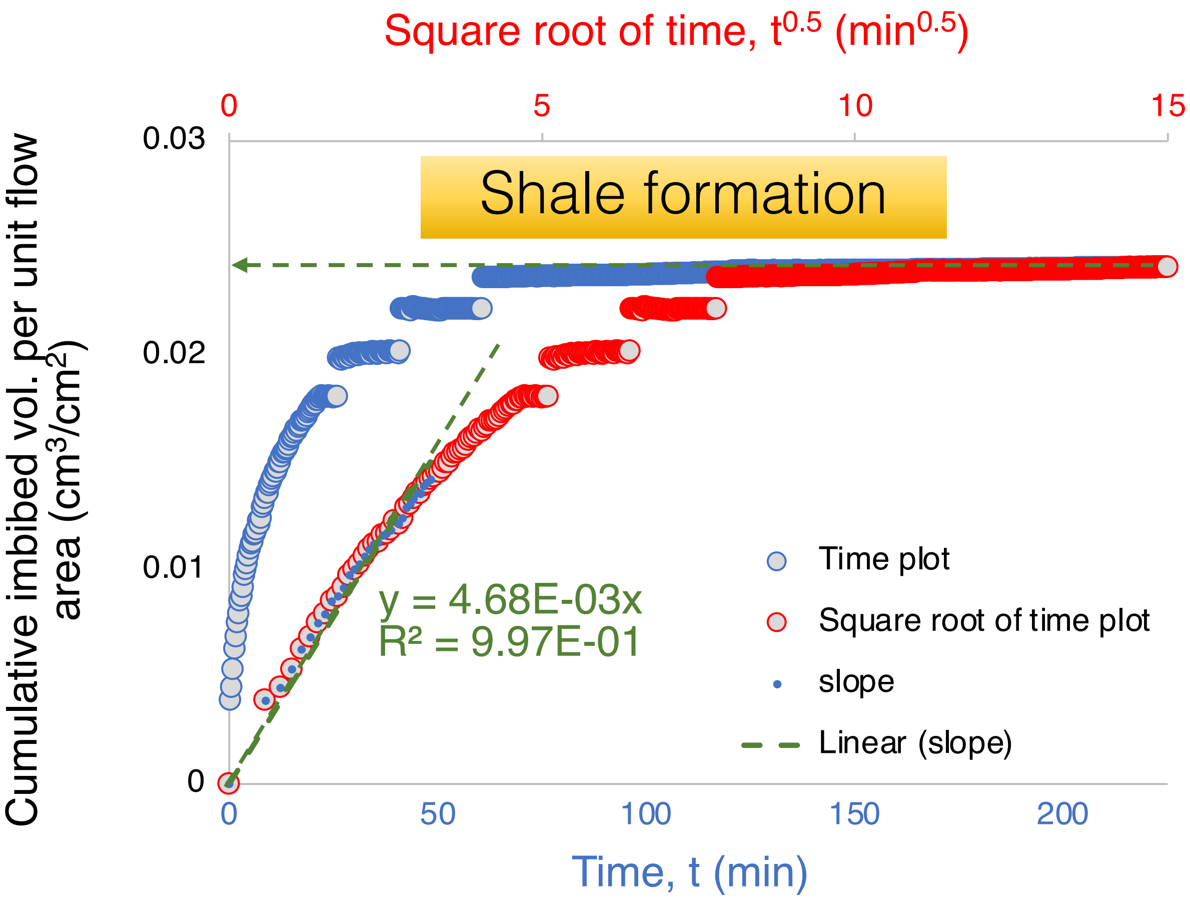
- Ingredients selected from Fracfocus.org database
- Mixing

- Rock samples:
  - ✓ Ceramic
  - ✓ Berea sandstone
  - ✓ 5 shale formations



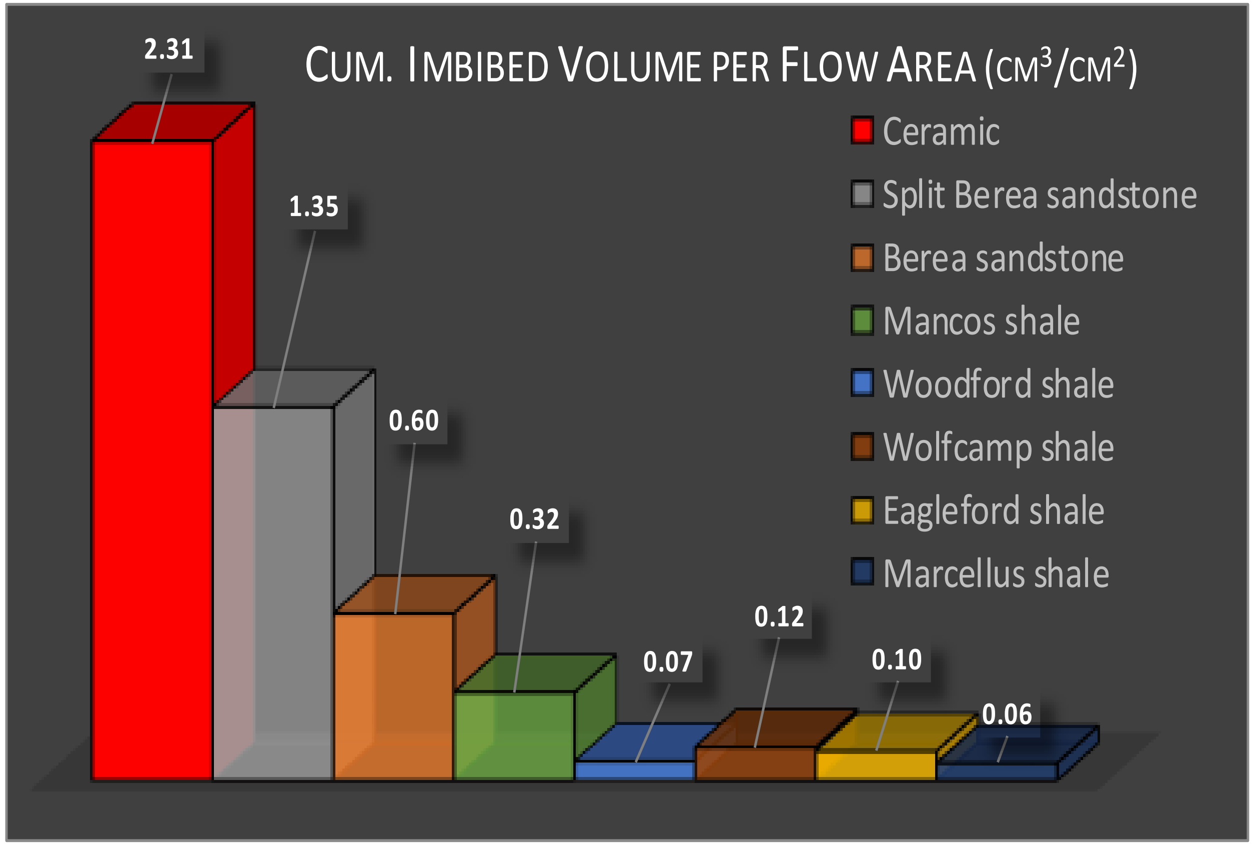
Water imbibition during shut-in period

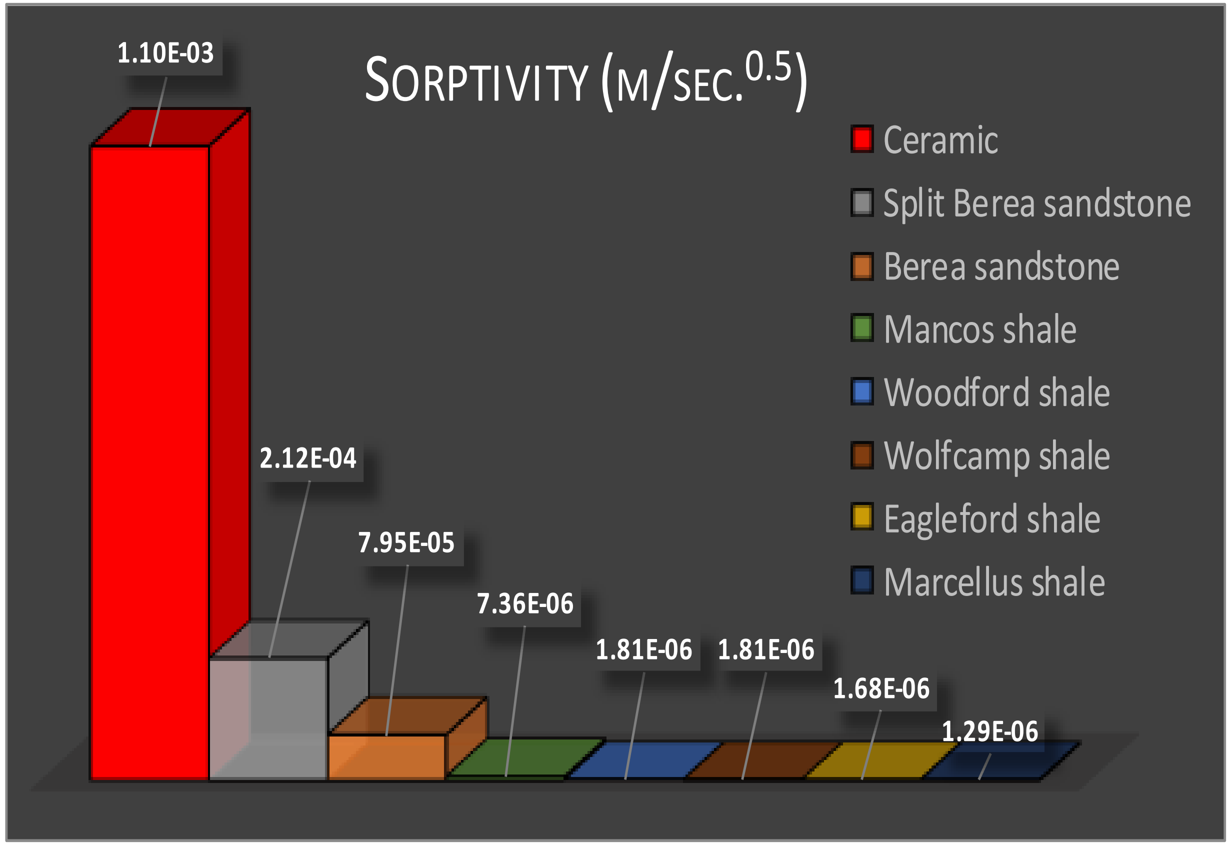




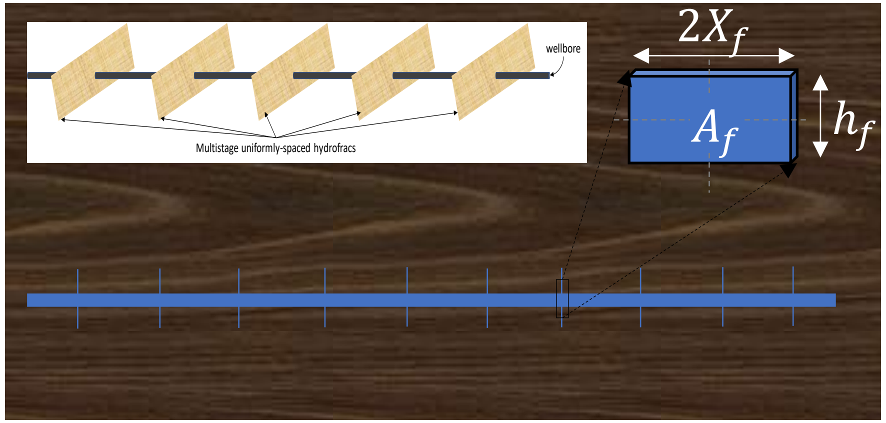
- Cumulative imbibed water is much lower in shale sample than in sandstone.

Cumulative imbibed volume and Sorptivity

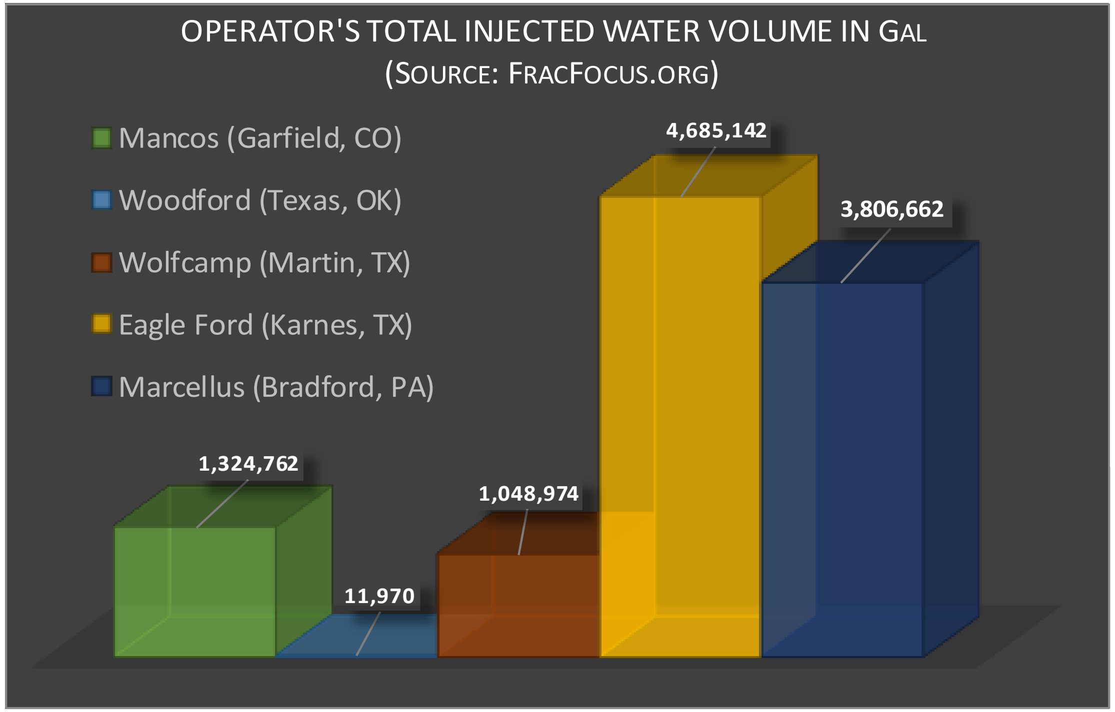


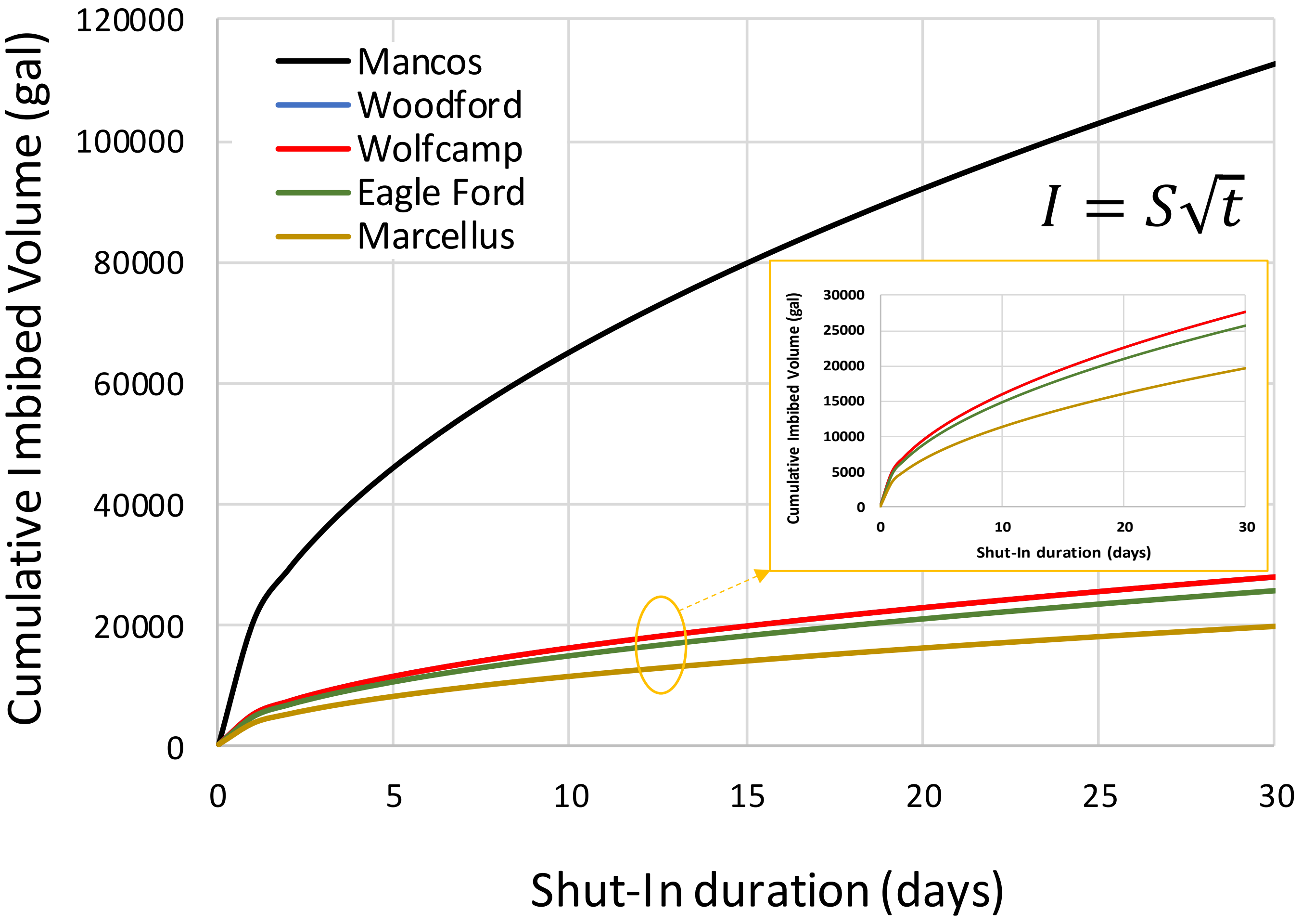


Case Study



$V_{leak\ off} = 10\%; w_f = 20\ /\ 40$ mesh; $N_f = 20$





Reducing shut-in time can minimize water-blockages in shales

Dependence of water-block damage on **capillary pressure** and **fluid viscosity** during countercurrent flow

- Li and Horne 2006

$$R^* \frac{dR^*}{dt_d} = 1 - R^*$$

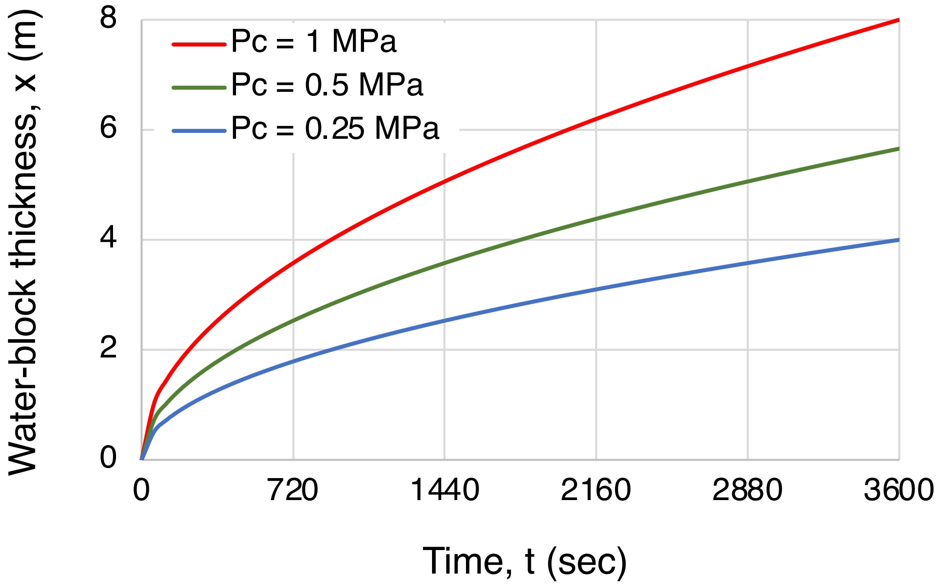
- Water-block thickness

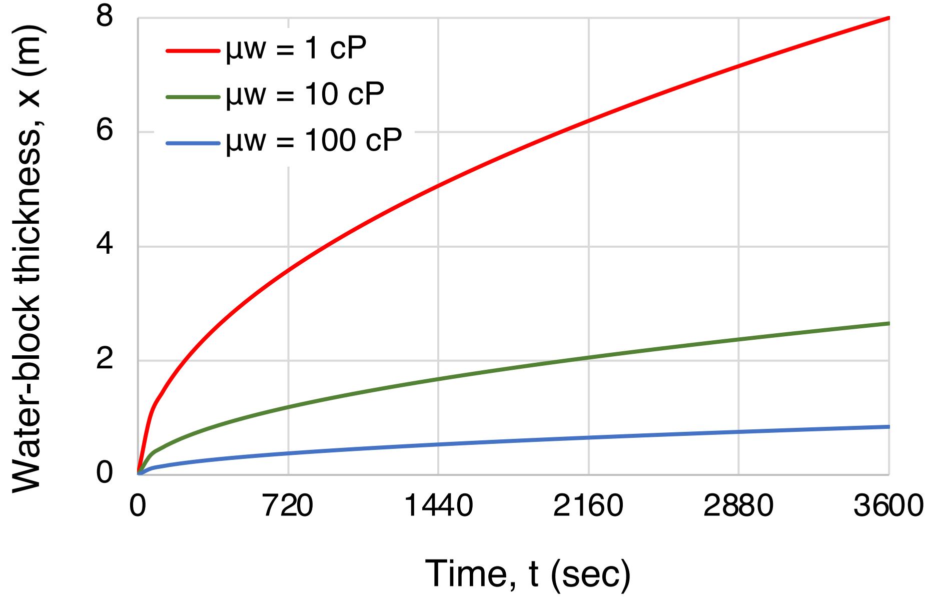
$$x = \sqrt{\frac{2M_e \boldsymbol{P_c}}{(S_{wf} - S_{wi})\phi}}\sqrt{t}$$

$$M_e = \frac{M_w M_{nw}}{M_{nw} + M_w} \quad \text{(Countercurrent flow)}$$

$$M_e = \frac{M_w M_{nw}}{M_{nw} - M_w} \quad \text{(Cocurrent flow)}$$

$$M_w = \frac{k_w}{\boldsymbol{\mu_w}};\ M_{nw} = \frac{k_{nw}}{\mu_{nw}}$$





Controllable parameters affecting capillary pressure and viscosity

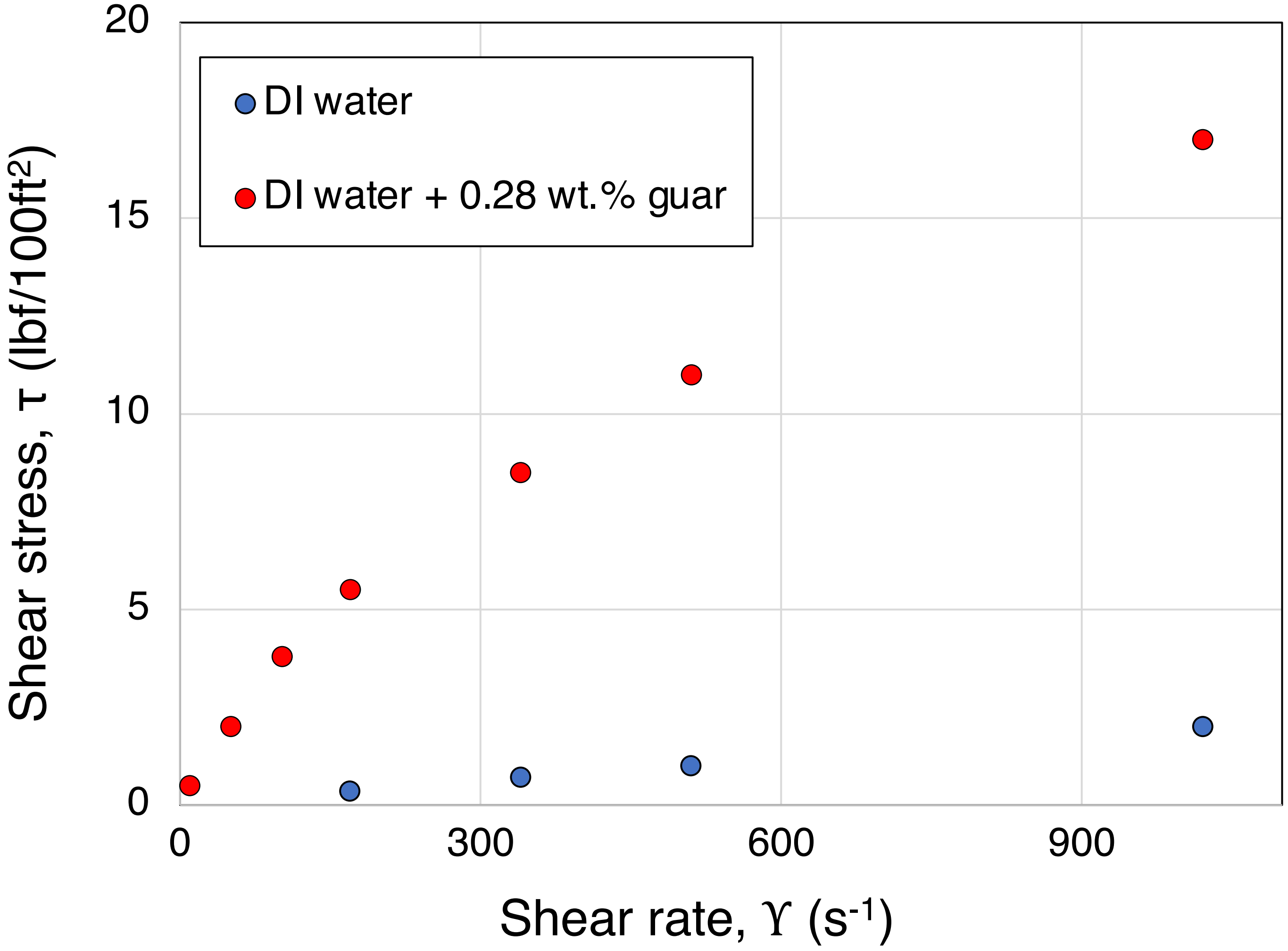
Capillary pressure, $P_c = \frac{2\boldsymbol{\sigma}cos\boldsymbol{\theta}}{\boldsymbol{r}}$

- Decreasing the interfacial tension (σ) between two fluids reduces capillary pressure.
  - ✓ Use of surfactant solutions
- Increasing the wettability angle (θ) reduces capillary pressure.
- Increasing the pore radius (r) reduces capillary pressure.
  - ✓ Small acid treatments near the wellbore

Fluid velocity, $v_f = -\frac{k}{\boldsymbol{\mu}}\frac{\partial P}{\partial x}$

- Increasing fluid viscosity (μ) reduces the rate of spontaneous imbibition.
  - ✓ Use of fluid thickener (gellant) e.g. Xanthan (guar) gum

Xanthan gum (Guar) increases the viscosity of water

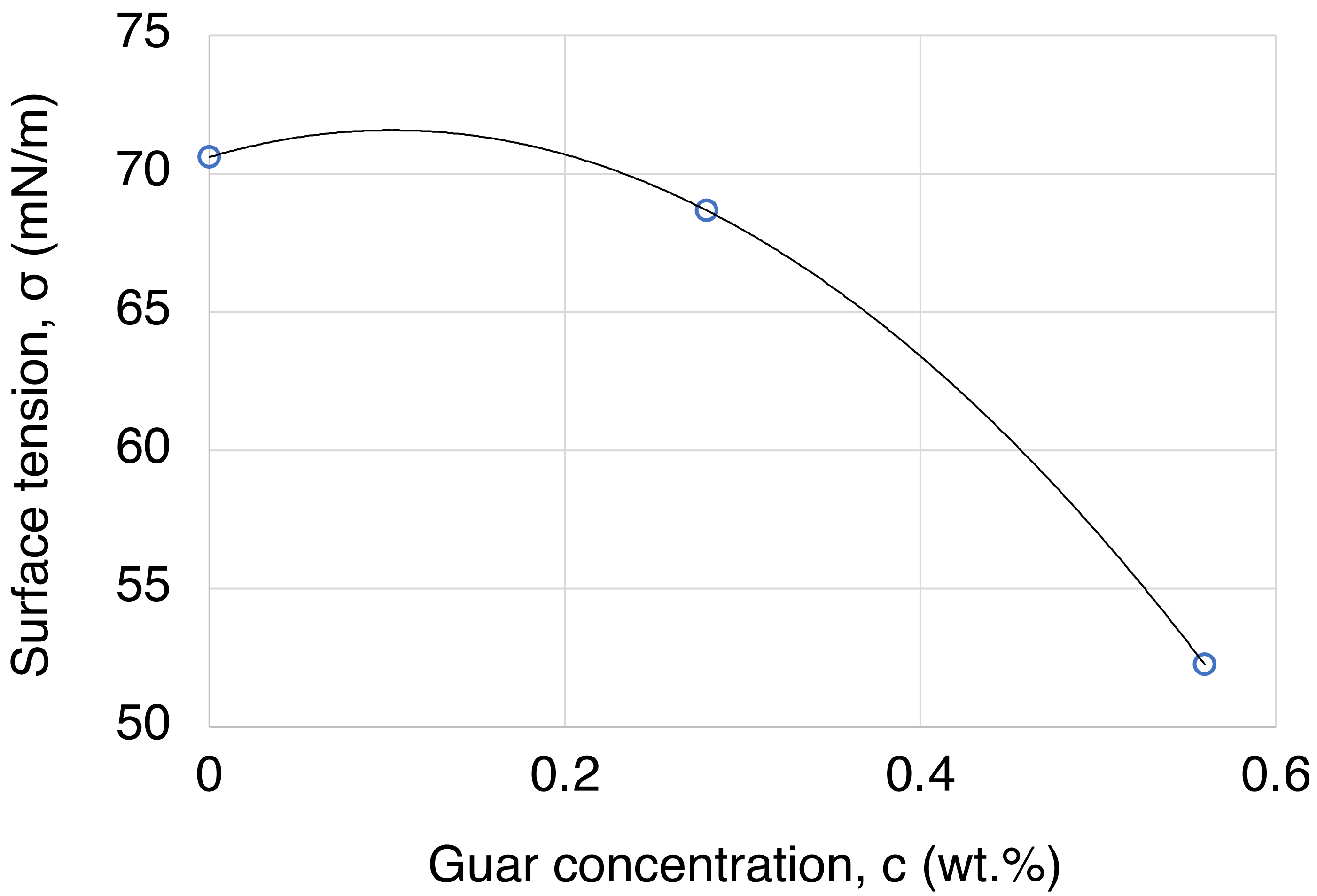


	DI water	DI water + 0.28 wt.% guar
Apparent viscosity, μ_a (cP)	1.00	9.25
Flow index, n	1.00	0.57
Consistency index, K (dyne-sec$^{0.57}$/cm^2)	1.00	1.87

- Viscosity of deionized water = 1.00 cP
- Viscosity of guar solution = 9.25 cP

Fluid velocity, $v_f = -\frac{k}{\mu}\frac{\partial P}{\partial x}$

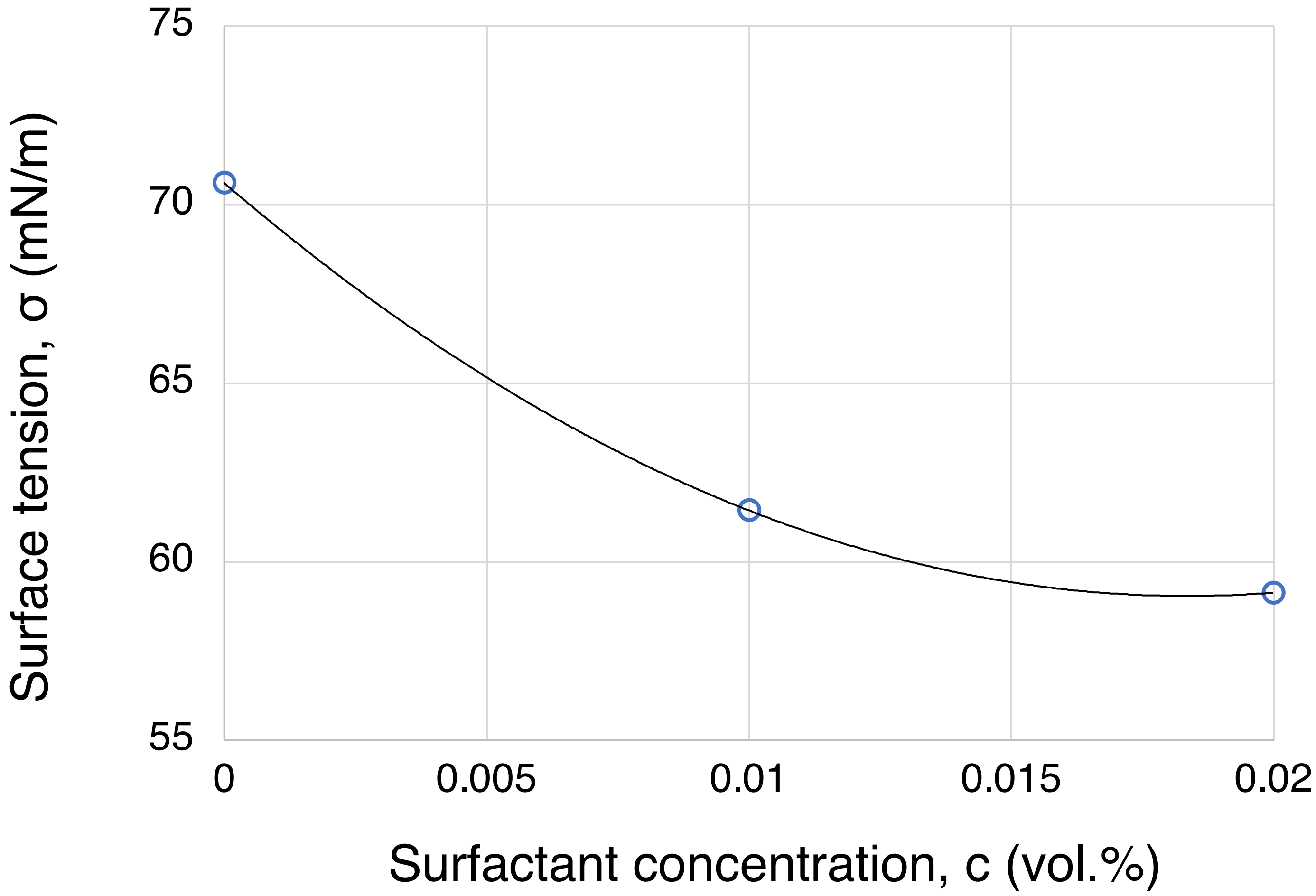
Effect of guar concentration on the surface tension of water



Capillary pressure, $P_c = \frac{2\boldsymbol{\sigma}cos\theta}{r}$

- Guar reduces the surface tension of water

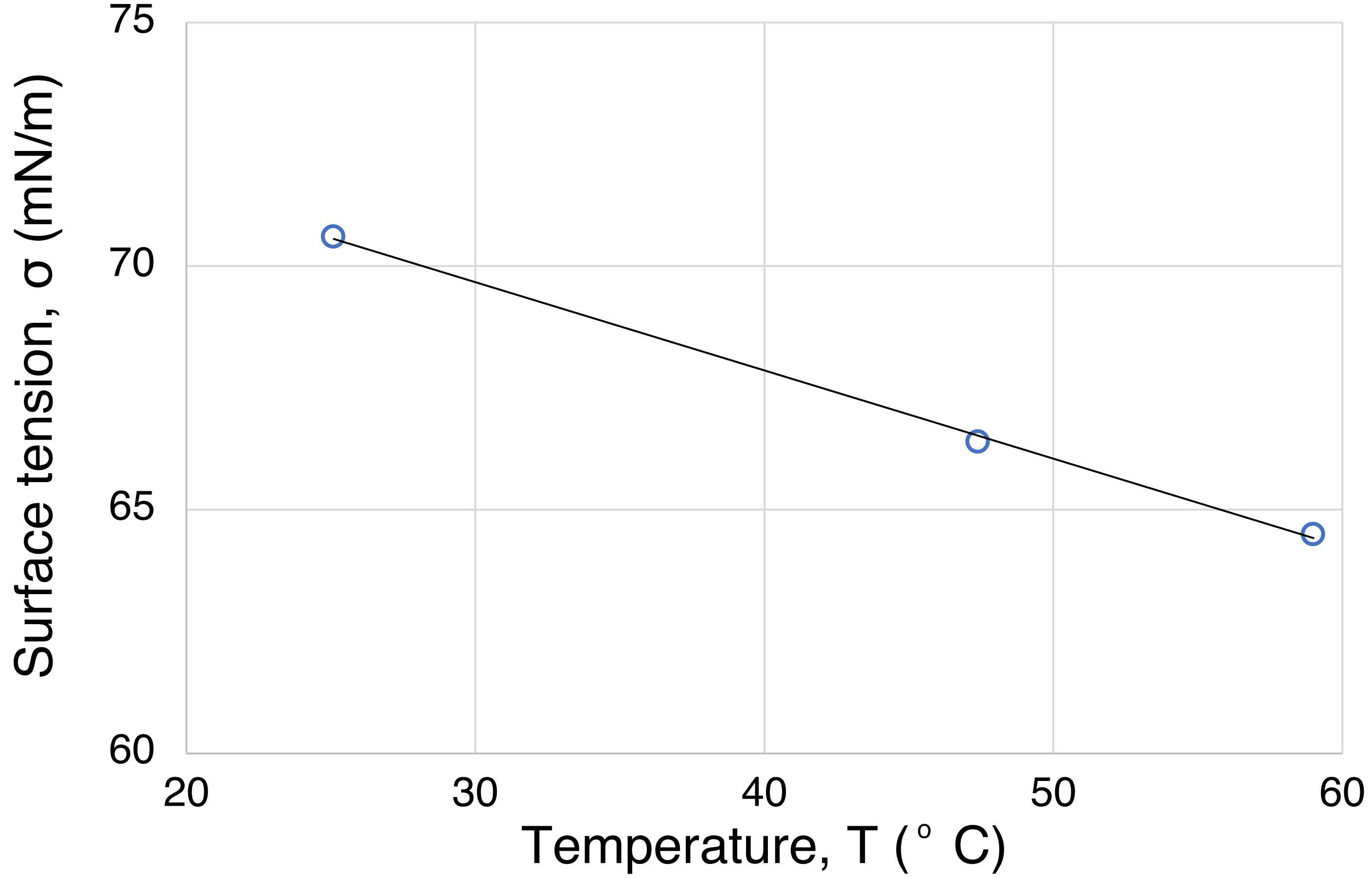
Effect of surfactant concentration on the surface tension of water



Capillary pressure, $P_c = \frac{2\boldsymbol{\sigma} cos\theta}{r}$

- Surfactant reduces the surface tension of water

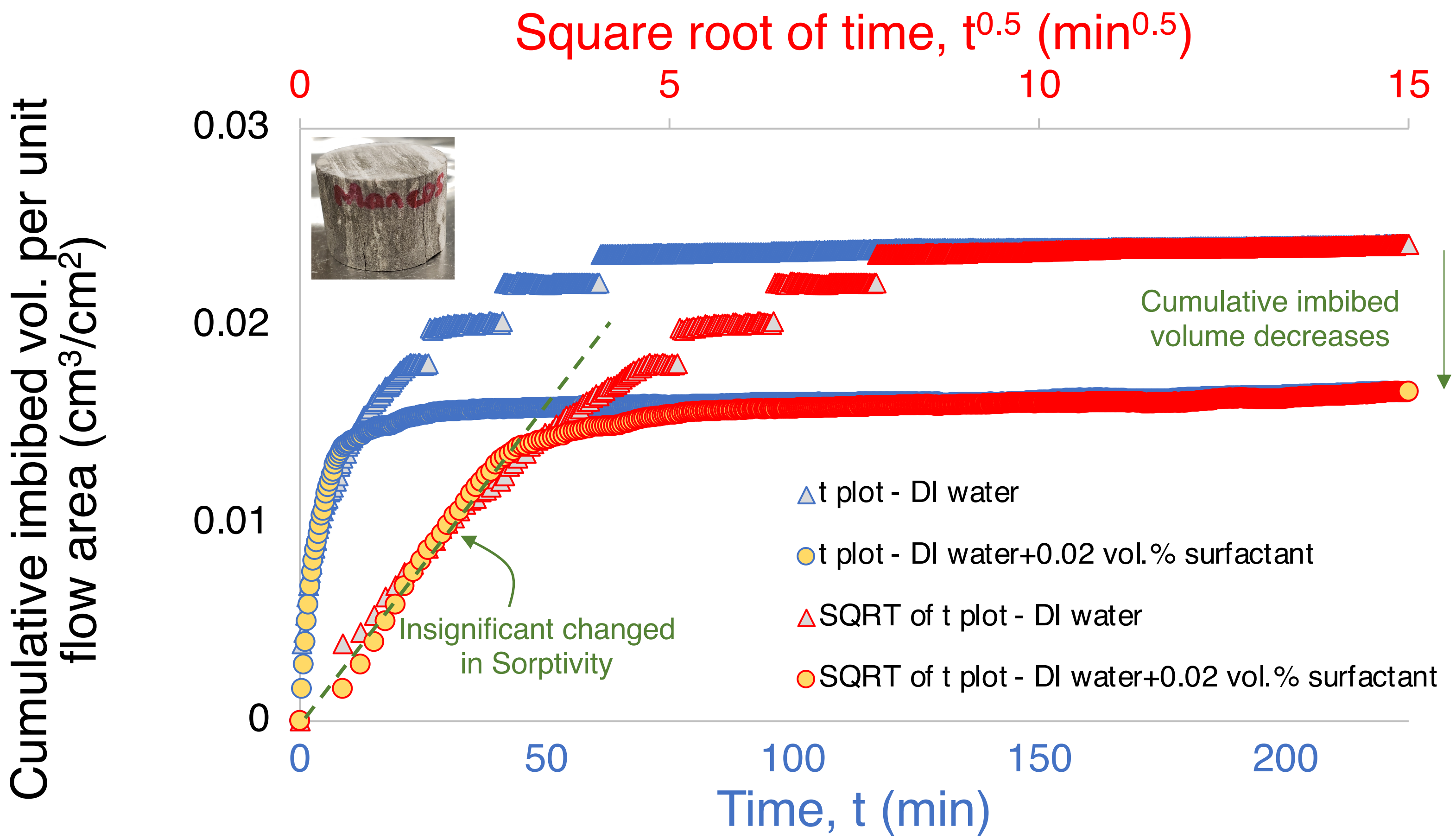
Effect of temperature on the surface tension of water



Capillary pressure, $P_c = \frac{2\sigma cos\theta}{r}$

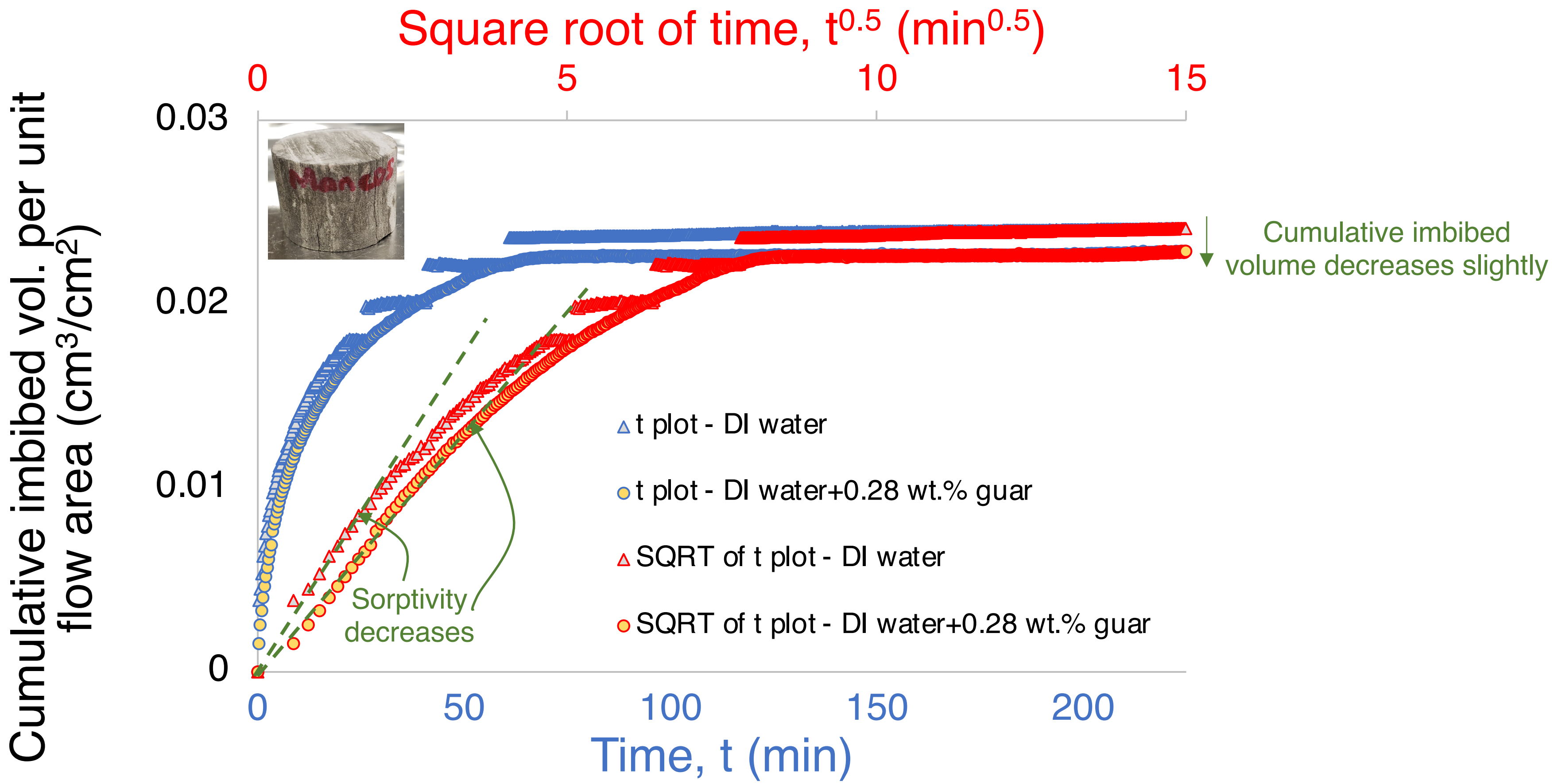
- Temperature reduces the surface tension of water

Use of surfactant may help to minimize water-block effects



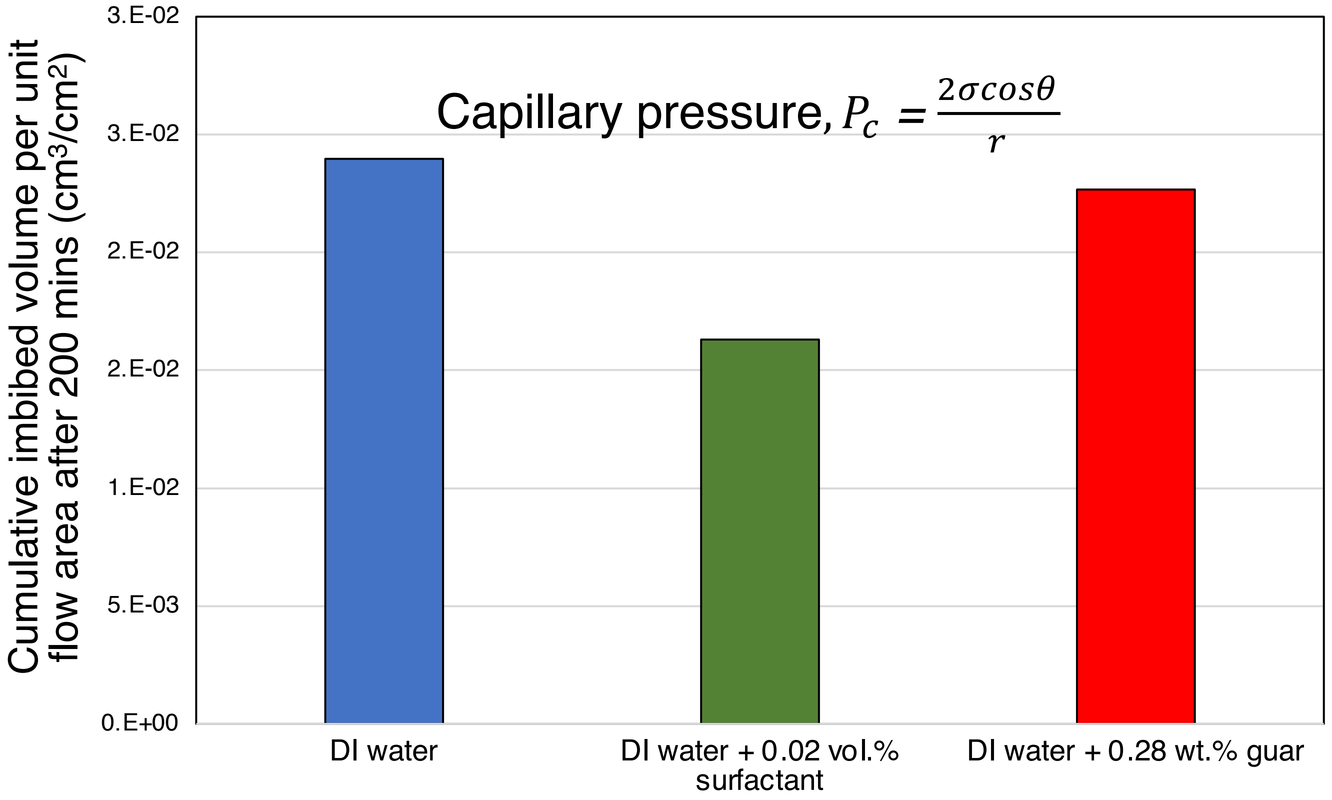
- Cumulative imbibed volume of pure deionized (DI) water is greater than that of the surfactant solution.

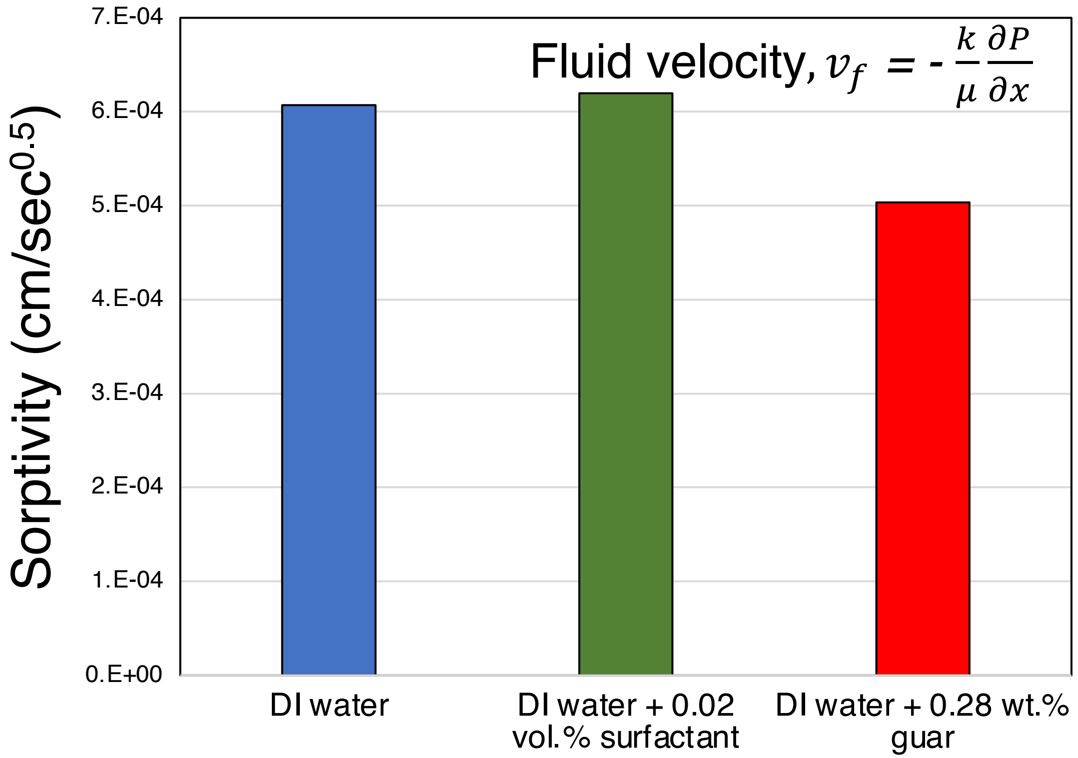
Use of thickened fluid may help to minimize water-block effects



- Imbibition rate of pure water is higher than that of the guar solution.

Results Summary





- Addition of surfactant to the base fluid decreased cumulative imbibed volume mainly due to reduction of the driving force (capillary pressure).
- Addition of guar to the base fluid decreased sorptivity mainly due to reduction of fluid velocity.
- Use of surfactant solution and thickened fluid generally reduces the cumulative imbibed volume and rate of imbibition into shale.

Summary

- Developed a practical relation for predicting imbibition into rocks.
- Shut-in wetting front distances are limited to cm scale into shale matrix.
- Recommend short shut-in times to minimize formation damage and reduce water loss.
- Recommend the use of thickened fluid and possible surfactants to reduce water loss.
- Developing method for direct measurements of water permeabilities in nano-Darcy materials.
- Developing physics-guided machine learning model for predicting spontaneous imbibition into porous and fractured media.

Publications from our Fundamental Shale project

Tokunaga, T.K., W. Shen, J. Wan, Y. Kim, A. Cihan, Y. Zhang, and S. Finsterle. 2017. Water saturation relations and their diffusion-limited equilibration in gas shale: Implications for gas flow in unconventional reservoirs. Water Resour. Res., 53, 9757-9770, DOI: 10.1002/2017WR021153.

Wan, J., T.K. Tokunaga, W. Dong, and Y. Kim. 2017. Extracting natural biosurfactants from humus deposits for subsurface engineering applications. Energy and Fuels, 31(11), 11902-11910, DOI: 10.1021/acs.enrgyfuels.7b02203.

Wang, L., J. Wan, T.K. Tokunaga, Y. Kim, Q. Yu. 2018. Experimental and modeling study of methane adsorption onto partially saturated shale. Water Resour. Res., 54, 5017-5029, DOI: 10.1029/2017WR020826.

Shen, W.J., L.G. Zheng, C.M. Oldenburg, A. Cihan, J. Wan, T.K. Tokunaga. 2018. Methane diffusion and adsorption in shale rocks: A numerical study using the dusty gas model in TOUGH2/EOS7C-ECBM. Transport in Porous Media 123, 3, 521-531, DOI: 10/1007/s11242-017-0985-y.

Cihan, A., T.K. Tokunaga, and J.T. Birkholzer. 2019. Adsorption and capillary condensation-induced imbibition in nanoporous media. Langmuir. DOI: 10.1021/acs.langmuir.9b00813.

Tokunaga, T.K. 2020. Simplified Green-Ampt model, imbibition-based estimates of permeability, and implications for leak-off in hydraulic fracturing. Water Resour. Res., 56, e2019WR026919. https://doi.org/10.1029/2019WR026919.

Next Steps

- Test imbibition-permeability relations in nano-Darcy shales.
- Test impacts of wettability on imbibition-permeability relations.
- Manipulate frac fluid wetting properties to minimize water damage
- Design and conduct experiments for counter-current gas flow
- Expand model to include nonlinear fluids under shut-in scenario