CHARACTERIZATION OF CO_2 STORAGE PROPERTIES USING CORE ANALYSIS TECHNIQUES AND THIN SECTION DATA

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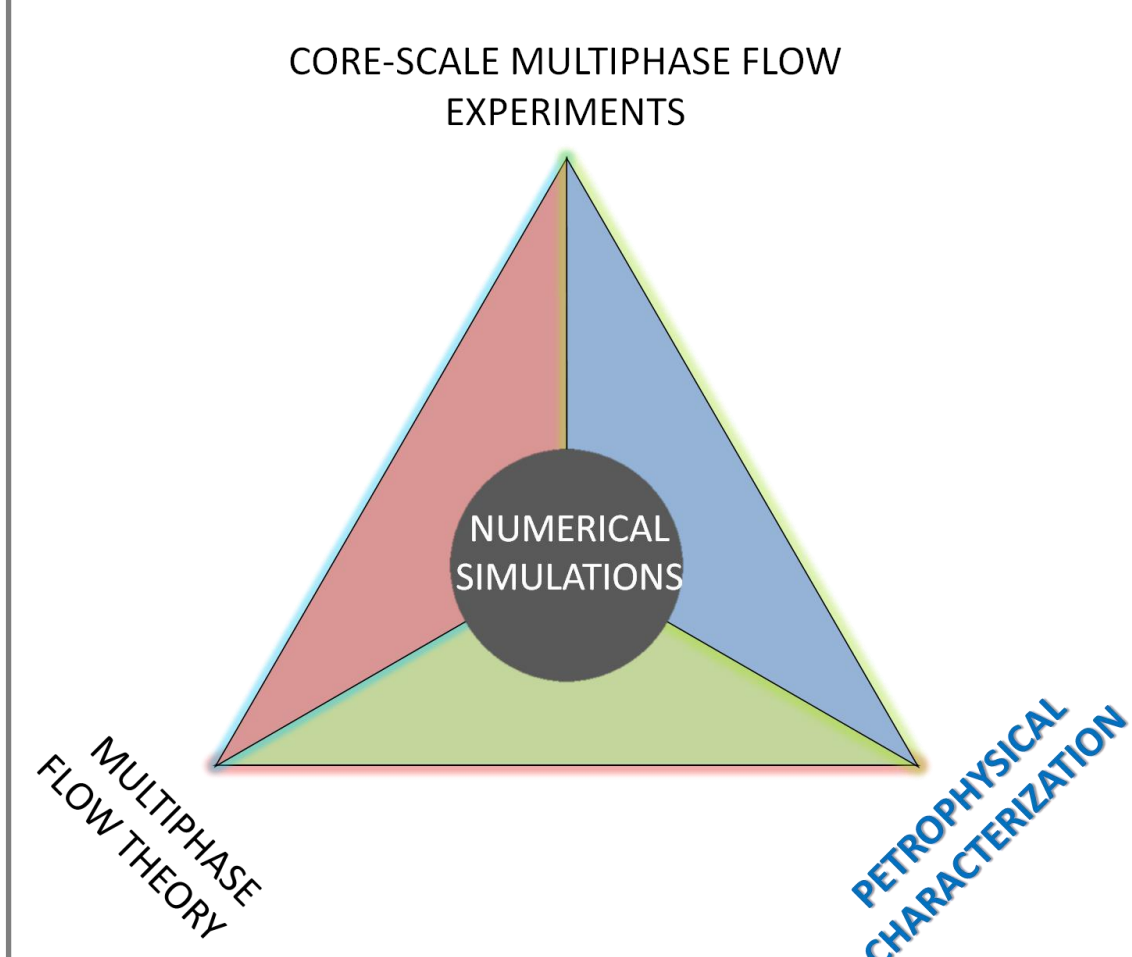**GCEP** — Global Climate & Energy Project — STANFORD UNIVERSITY

PORE SCALE ANALYSIS

A great deal of effort has gone into understanding the physics of multiphase flow and into representing this behavior at the reservoir scale for hydrocarbon recovery, CO_2 sequestration and a wide range of other applications. Fundamental to our understanding of how fluids behave in the subsurface is the use of simulation to study how fluids interact and behave under various conditions. Despite the well documented theoretical developments of various phenomena, experimental results from core experiments in which CO_2 is injected into a brine saturated core under controlled conditions cannot be accurately replicated using simulation. The sequestration lab seeks to resolve this issue by taking a multi-disciplinary approach.

CORE-SCALE MULTIPHASE FLOW EXPERIMENTS

NUMERICAL SIMULATIONS

MULTIPHASE FLOW THEORY

PETROPHYSICAL CHARACTERIZATION

THE SEQUESTRATION LAB
The goal of the Sequestration Lab is to develop the ability to predict the spatial and temporal distribution of CO_2 saturation and trapping through an improved understanding of the pore and core scale physics over the life cycle of a sequestration project.

How this work fits in
One of the most important parts of testing the physics is bridging the gap between scales. The goal of this work is to study the **integration of pore scale features into core scale models**, particularly the development of a method by which to accurately calculate permeability from porosity data.

PORE SCALE MEASUREMENT

Scan thin section and convert to a binary image so that porosity matches the measured core average
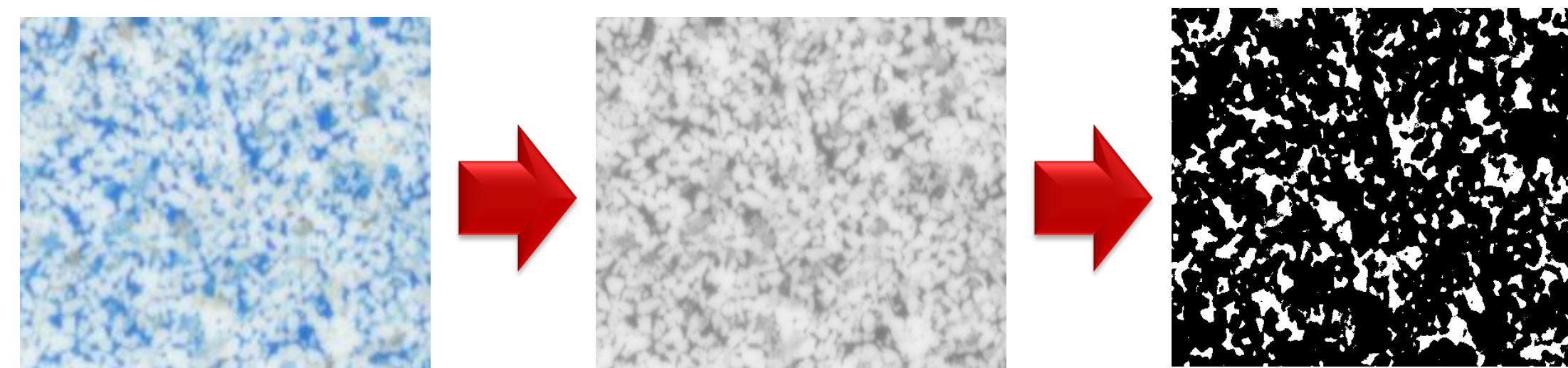
Sum all pore perimeters in a sample area
Sum the area of pore area in the same sample area

2.12 mm

For this Sample:
ϕ – 10.02%
a_v – 0.005294 $\mu m/\mu m^2$
k – 111.48 md
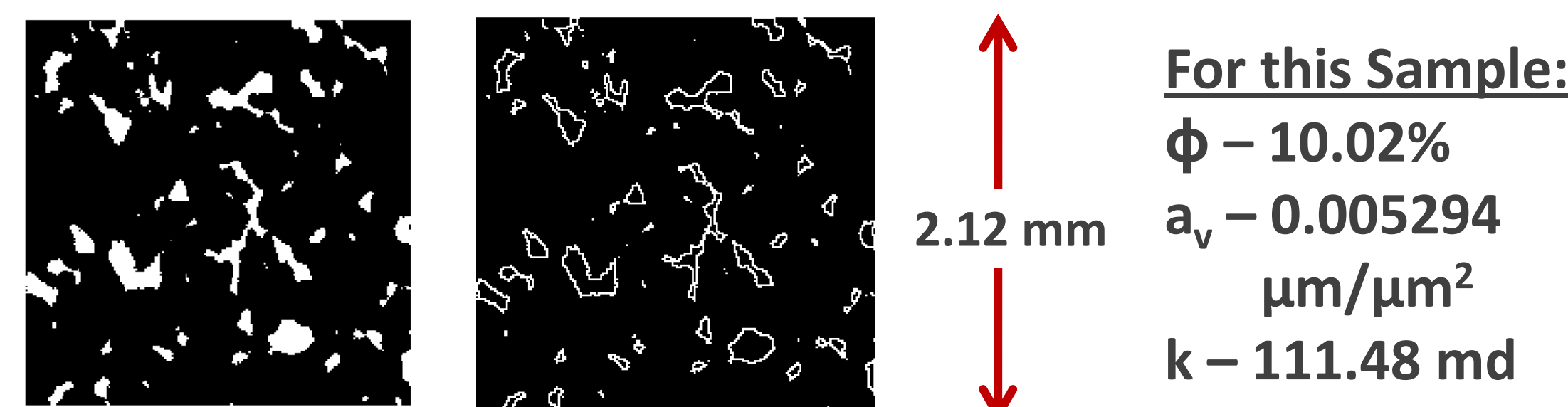
THEORETICAL DEVELOPMENT

Porosity data comes from using a CT device to scan the core, from this porosity data, permeability and capillary pressure are calculated
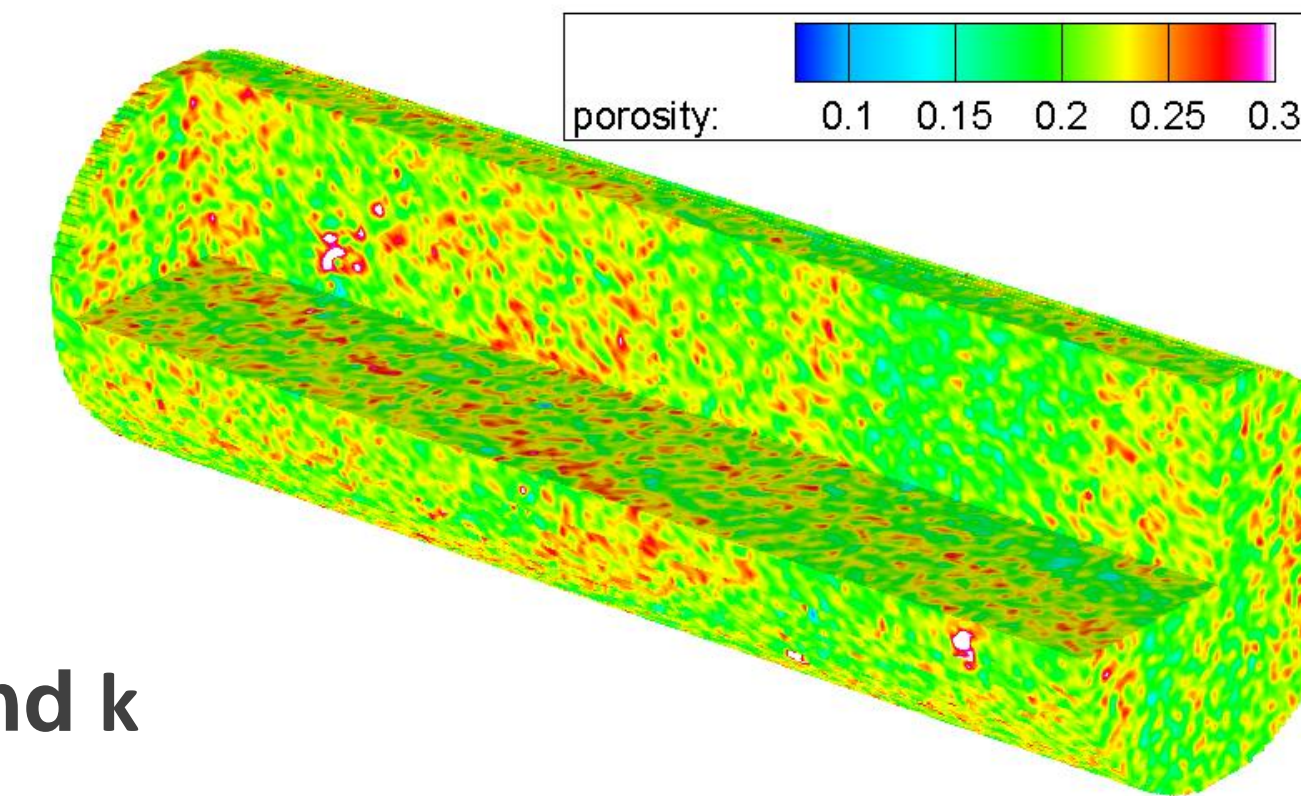
Carman-Kozeny Equation – Equation 1

$$k = \frac{\phi^3}{S(1-\phi)^2}$$

S is a core scale empirical constant

Leverett's J-Function

$$P_{c,i} = \sqrt{\frac{\phi_i}{k_i}} \cdot J(S_w)$$

P_c is a Function of ϕ and k

Can include pore scale information relating S to porosity to improve the relationship which correlates porosity and permeability

This form of the Carman-Kozeny equation includes specific surface area, or the total surface area per unit volume, this quantity can be measured and correlated to porosity.

$$k = \frac{\phi^3}{2\tau \cdot a_v^2 \cdot (1-\phi)^2}$$

τ – Tortuosity
a_v – Specific Surface Area

Measure a_v in a 2-D Rock Section and Relate to Porosity

We can use a thin section to **measure a_v and porosity** and develop a relationship between a_v and ϕ, using regression analysis, which can be substituted into the equation. Since a thin section is a 2-D representation, a_v is the **specific perimeter**, or the length of perimeter per unit area.

$$k = \frac{S}{(\mathcal{F}(\phi))^2}\frac{\phi^3}{(1-\phi)^2} \qquad a_V = \frac{\sum Perimeter}{Measured\ Area}$$

New Carman-Kozeny Equation for Berea 1– Equation 2

$$k = \frac{S}{(0.0316\phi^{0.7593})^2}\frac{\phi^3}{(1-\phi)^2}$$

CONCLUSIONS AND FUTURE WORK

MORE PERMEABILITY CONTRAST MAY BE REQUIRED
The saturation is partially dependent upon capillary pressure, increasing the permeability contrast can increase the saturation contrast and may lead to a better match between experiments and simulation.

RELATIVE PERMEABILITY SHOULD ALSO BE INVESTIGATED
The saturation distribution in the core is also controlled by relative permeability, therefore, further testing is required to determine the relative impact of both a precise permeability characterization, and an accurate relative permeability definition for the core.

MULTIPLE PERMEABILITY RELATIONSHIPS ARE POSSIBLE
Especially in a heterogeneous core, a permeability relationship could be developed for different rock types found within the core if thin sections could be isolated from such areas. These could be applied if porosity values are used to define separate regions.

ADDITIONAL THIN SECTIONS NEED TO BE EVALUATED
To precisely determine what the impact of heterogeneity has on the permeability functions which are derived, additional thin sections must be evaluated which are targeted from different rock types found within the same core.

## THIN SECTION ANALYSIS AND SIMULATION RESULTS

Specific perimeter vs. porosity for three sandstone thin sections

COMMENTS
All samples have qualitatively similar relationships between the amount of perimeter and porosity over the expected porosity range.

Berea Sandstone 2 is more homogeneous than Berea 1 but has a weaker relationship between specific perimeter and porosity.

The smaller the sample area in the thin section, the more data points in the plot, but the more error is introduced due to boundary effects.

Specific Perimeter of Sandstone Cores
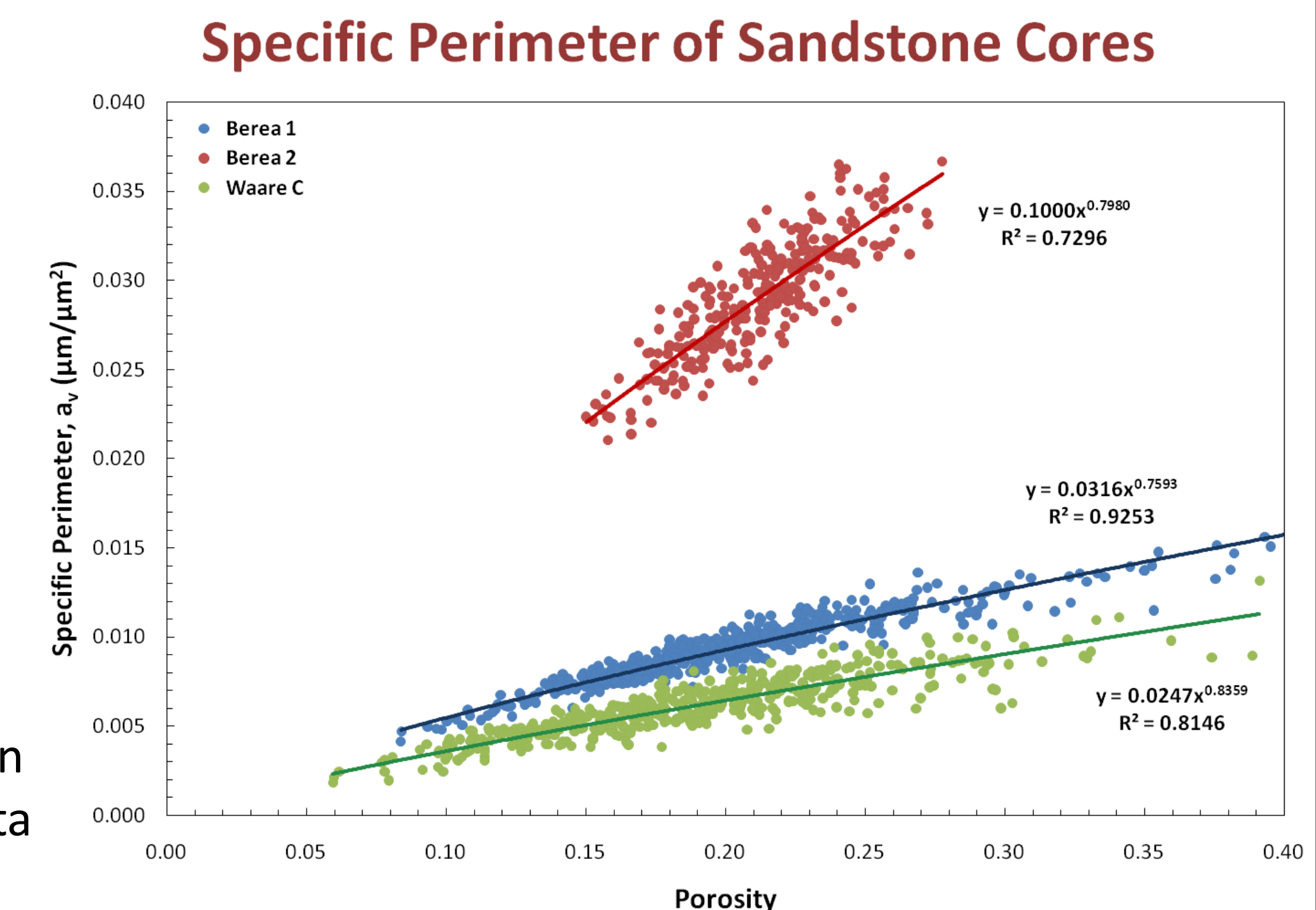
Berea 1 CO_2 saturation at steady state for 50 percent CO_2 injection
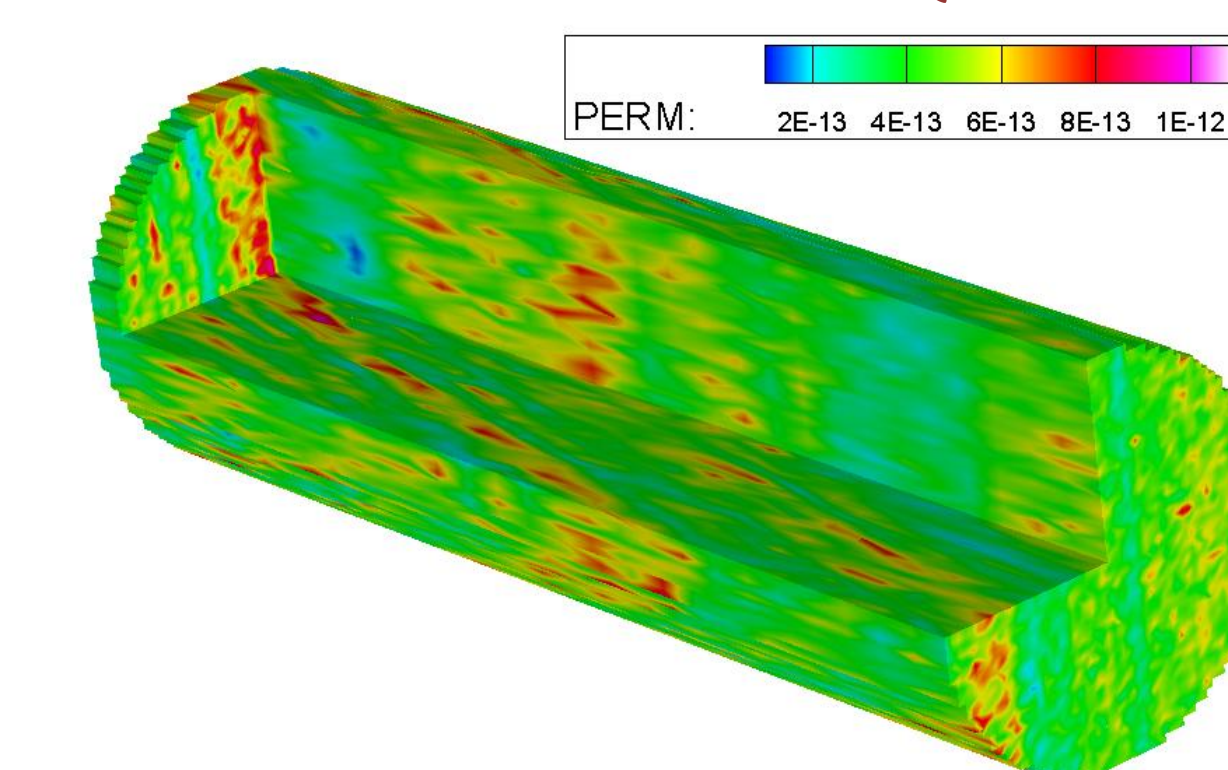
COMMENTS
Changes in saturation distribution are observed by changing the permeability calculation, but still does not match experimental results.
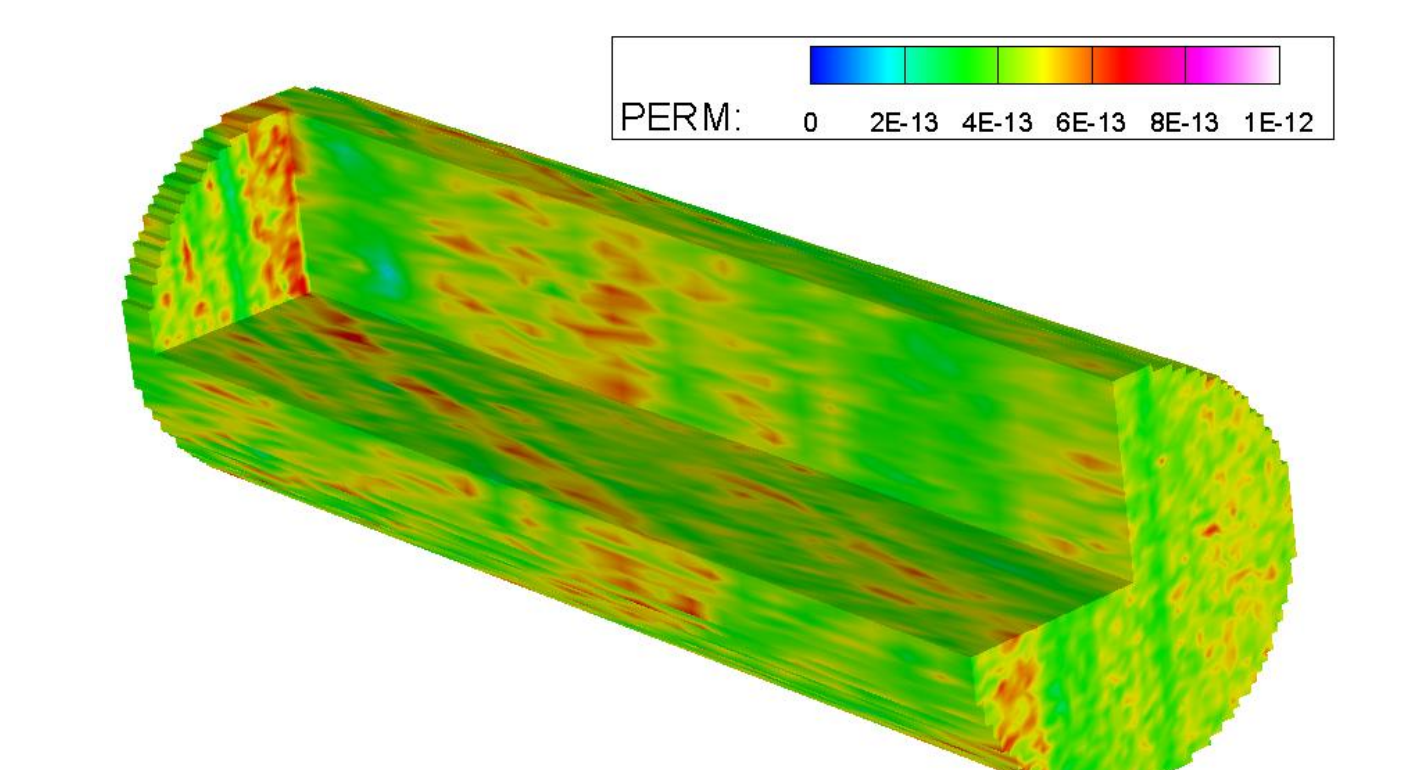
There is less spatial contrast in saturation distribution using Eq. 2 to calculate permeability compared to using the simple Carman-Kozeny relationship in Eq. 1.

Structural features in the core are obvious and have a strong effect but have no special or specific treatment.
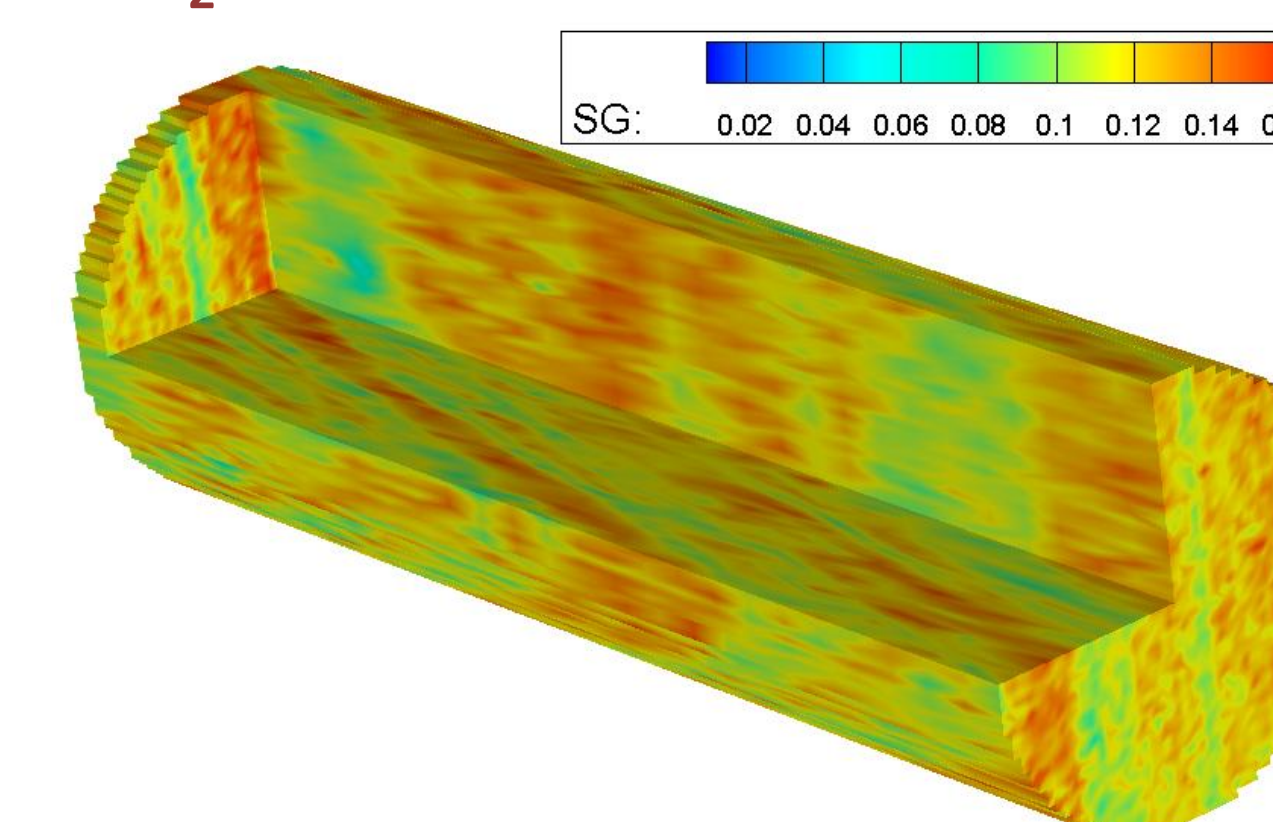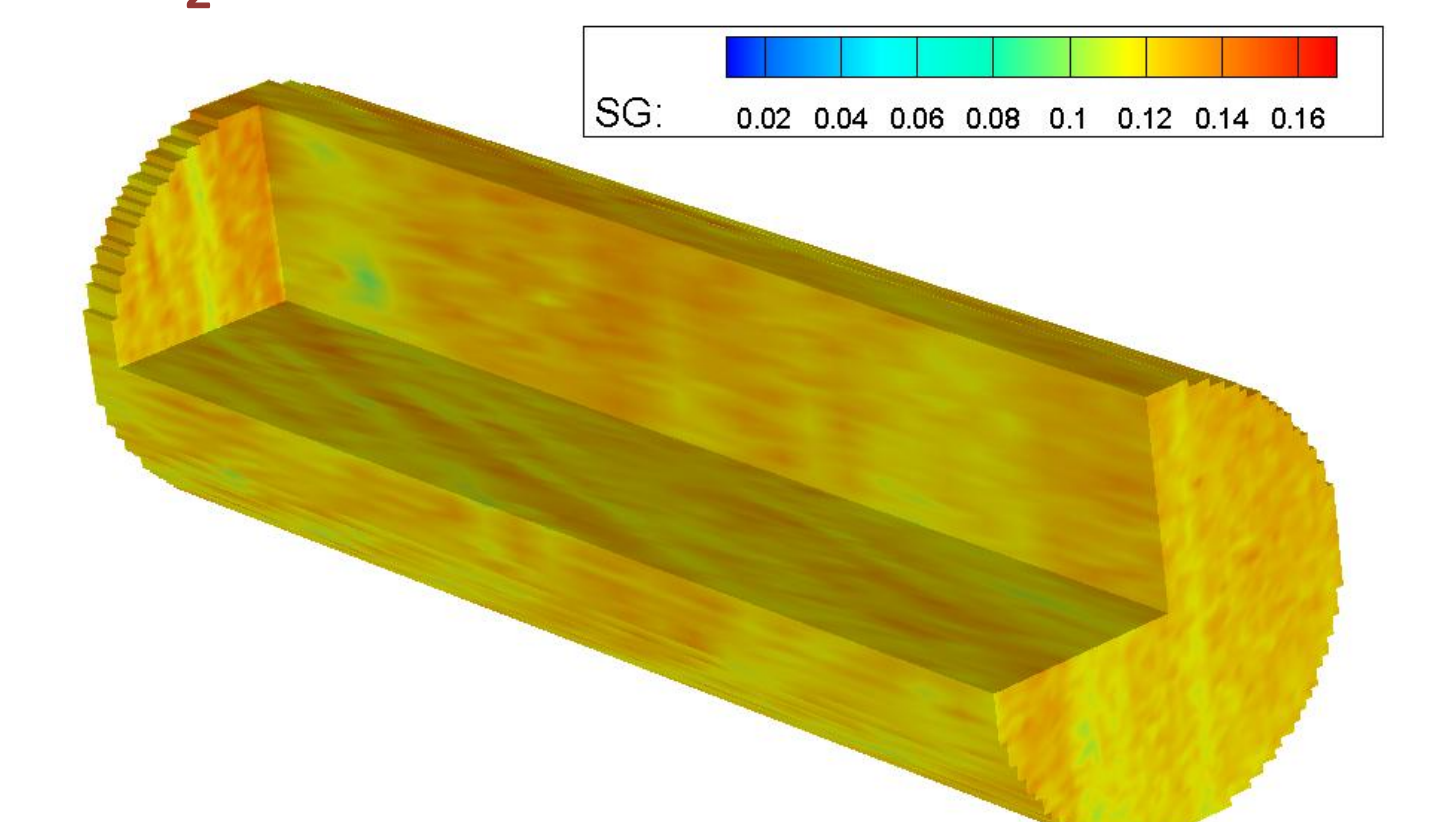
PERMEABILITY USING EQUATION 1
PERMEABILITY USING EQUATION 2
CO_2 SATURATION USING EQUATION 1
CO_2 SATURATION USING EQUATION 2

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