Three-Phase Relative Permeability

SPE Distinguished lecture tour 2001/2002

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Imperial College

- Centre for Petroleum Studies – Director Prof. Alain Gringarten – umbrella organisation for all oil-related research plus MSc teaching.
- Petroleum Engineering and Rock Mechanics Group – head Prof. Martin Blunt – eight faculty working exclusively in the petroleum area, ten post-docs and 25 PhD students.
- Cover full range of petroleum engineering – experimental, theoretical and numerical work with an emphasis on reservoir management.

Introduction

- Why three-phase flow is important
- Pore-scale picture of flow
- Experimental measurements of three-phase relative permeability
- Pore-scale modelling of three-phase flow
- Empirical modelling
- The big picture – pore-to-core-to-reservoir upscaling

Why three-phase flow?

- Gas cap expansion, reservoir blow-down, solution gas drive, gas injection (produced gas, carbon dioxide, steam flooding).
- Reduce oil to low saturation.
- Oil recovery rate determined by oil relative permeability at low saturation.
- Measurements and models may differ by orders of magnitude.
- First order uncertainty in performance predictions.

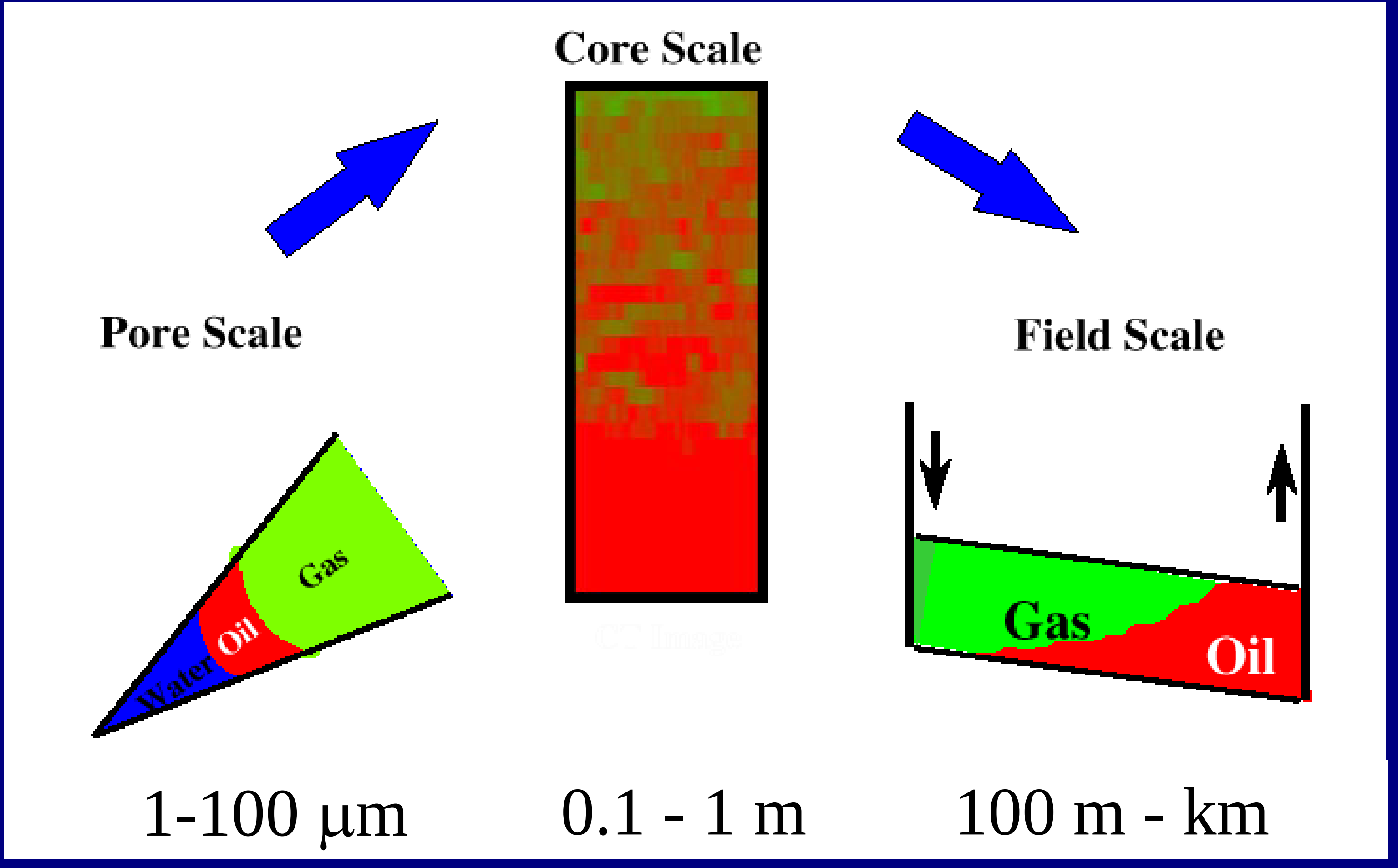
Field example

- Boscán field,Venezuela. Heavy oil (20-400cp at resevoir conditions). In excess of 26 billion bbl of oil originally in place. Primary recovery 7-8% at best.
- Consider steam injection and/or solution gas drive (SPE 69723, Kumar et al). Possible 40% recovery with favorable three-phase relative permeabilities (linear interpolation).
- Three-phase flow with oil flowing at saturations in the 30-40% range.

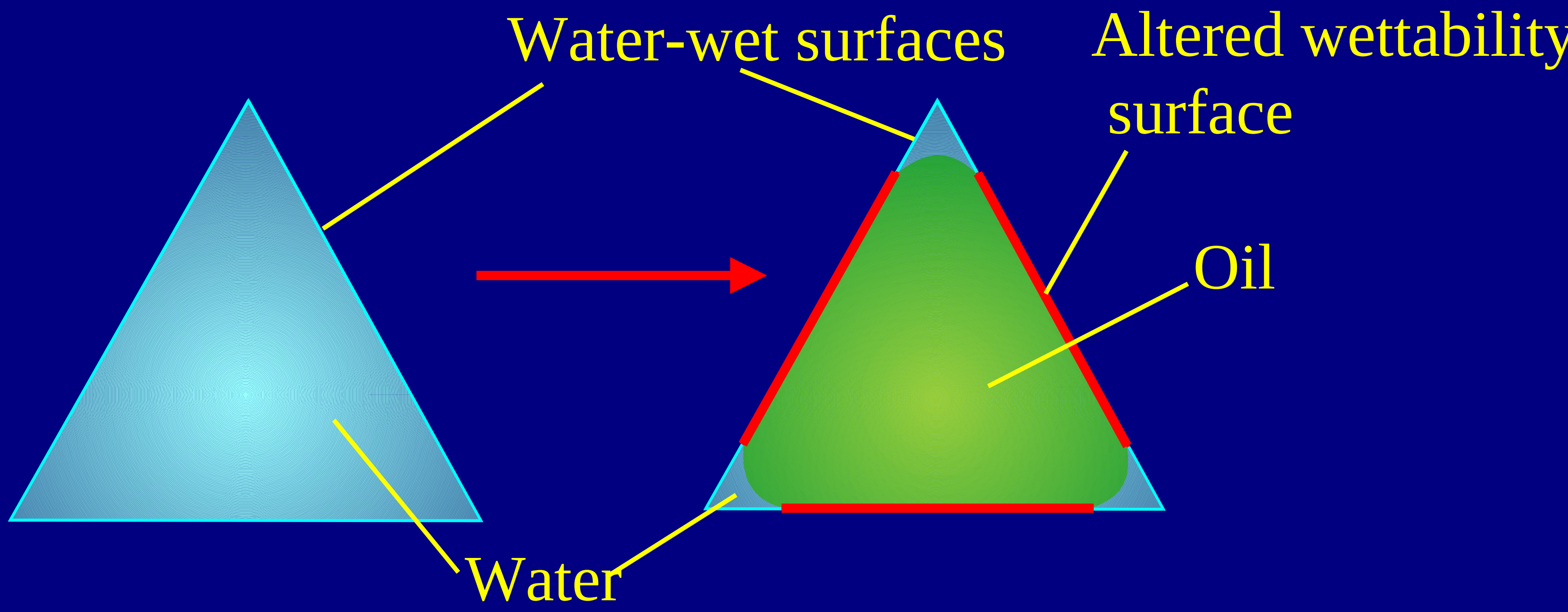
Field example (continued)

- Conventional three-phase relative permeability models vary in their predictions of oil relative permeability by a factor of 10 for this saturation range.
- This has a direct impact on oil recovery rate. A relative permeability at the low end of the possible range leads to very slow oil recovery and an inefficient displacement. Particularly important for solution gas drive.
- Even greater effects in light oil reservoirs where even lower oil saturations are reached (in the 10 – 20% range)

Different length scales



Displacements in the pore space

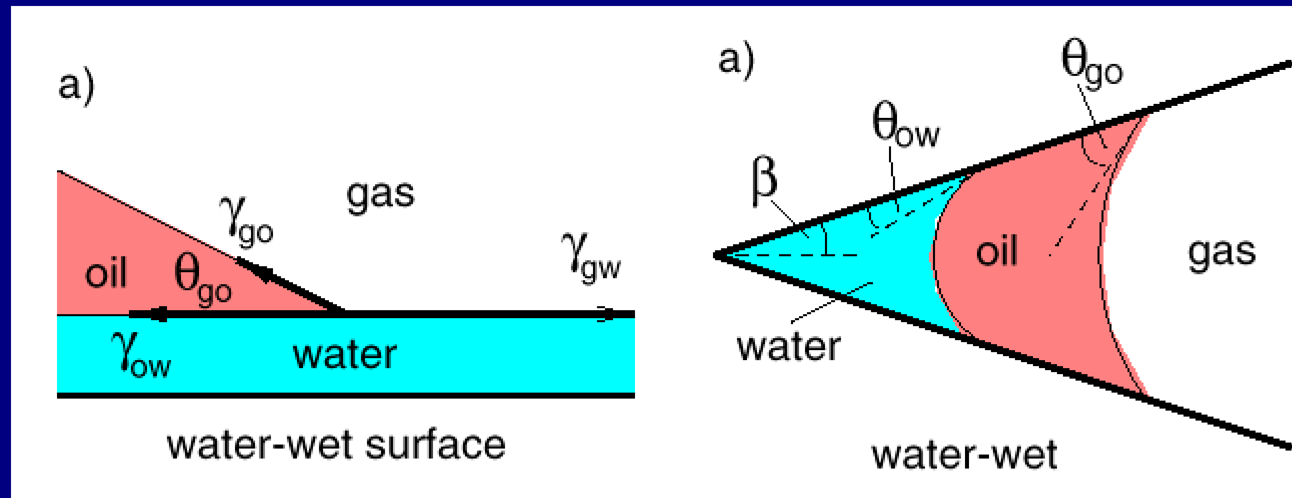


Most sedimentary rock is naturally water-wet. Oil migrates into reservoir rock. Where the oil is in contact with solid surfaces, the surface changes its wettability.

Why ducks don’t get wet

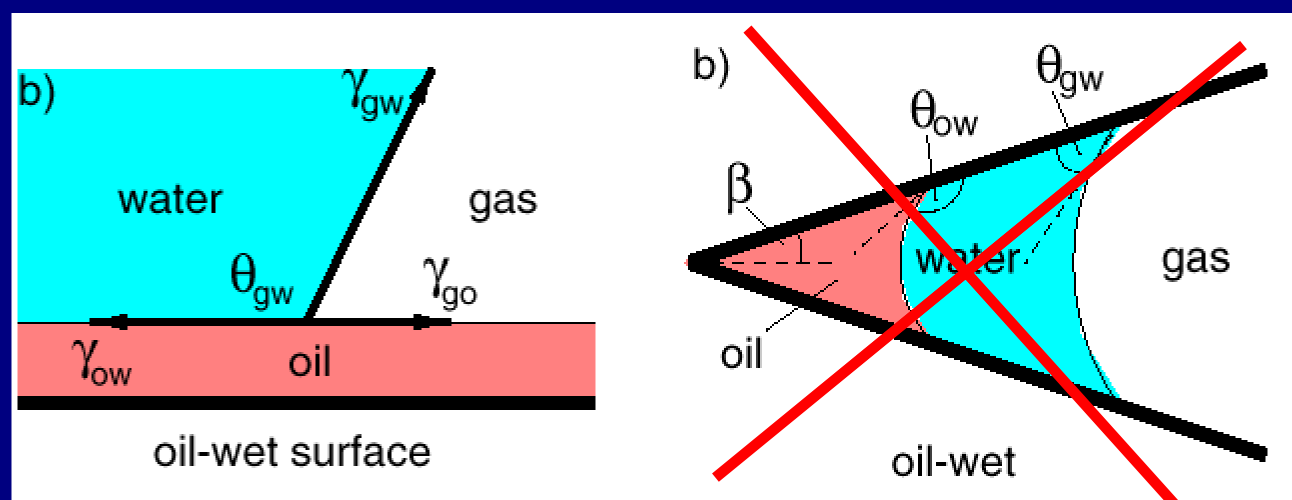
Water-wet:

$$\gamma_{gw} = \gamma_{ow} + \gamma_{go} \cos \theta_{go}$$

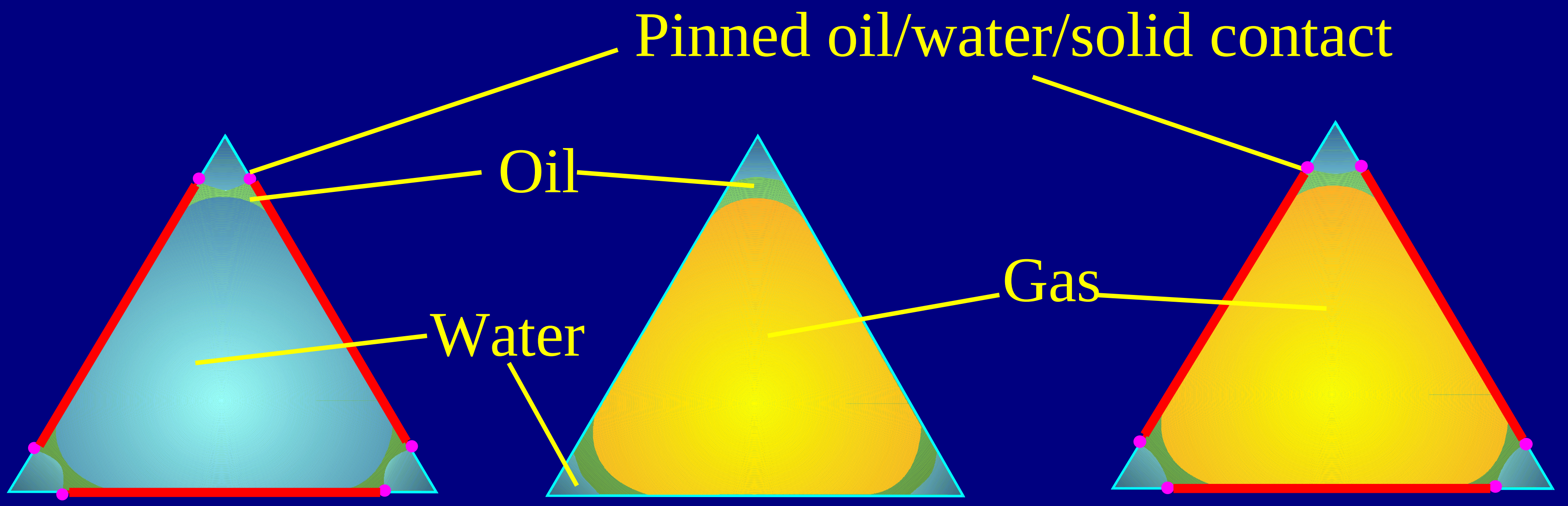


Oil-wet:

$$\gamma_{go} = \gamma_{ow} + \gamma_{gw} \cos \theta_{gw}$$



Water and gas injection

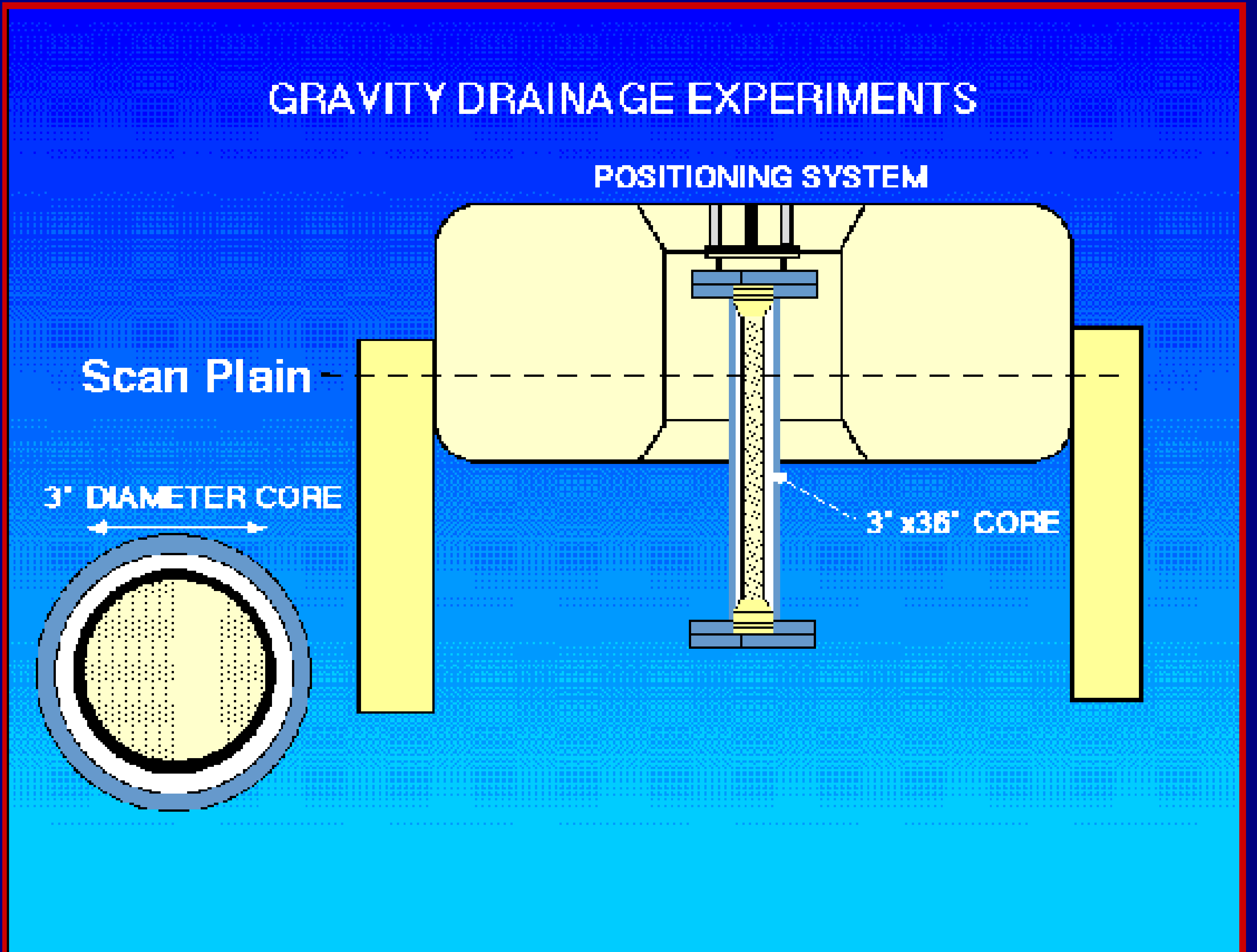


Mixed-wet. After water injection.
$\theta_{ow} < 120^o$.

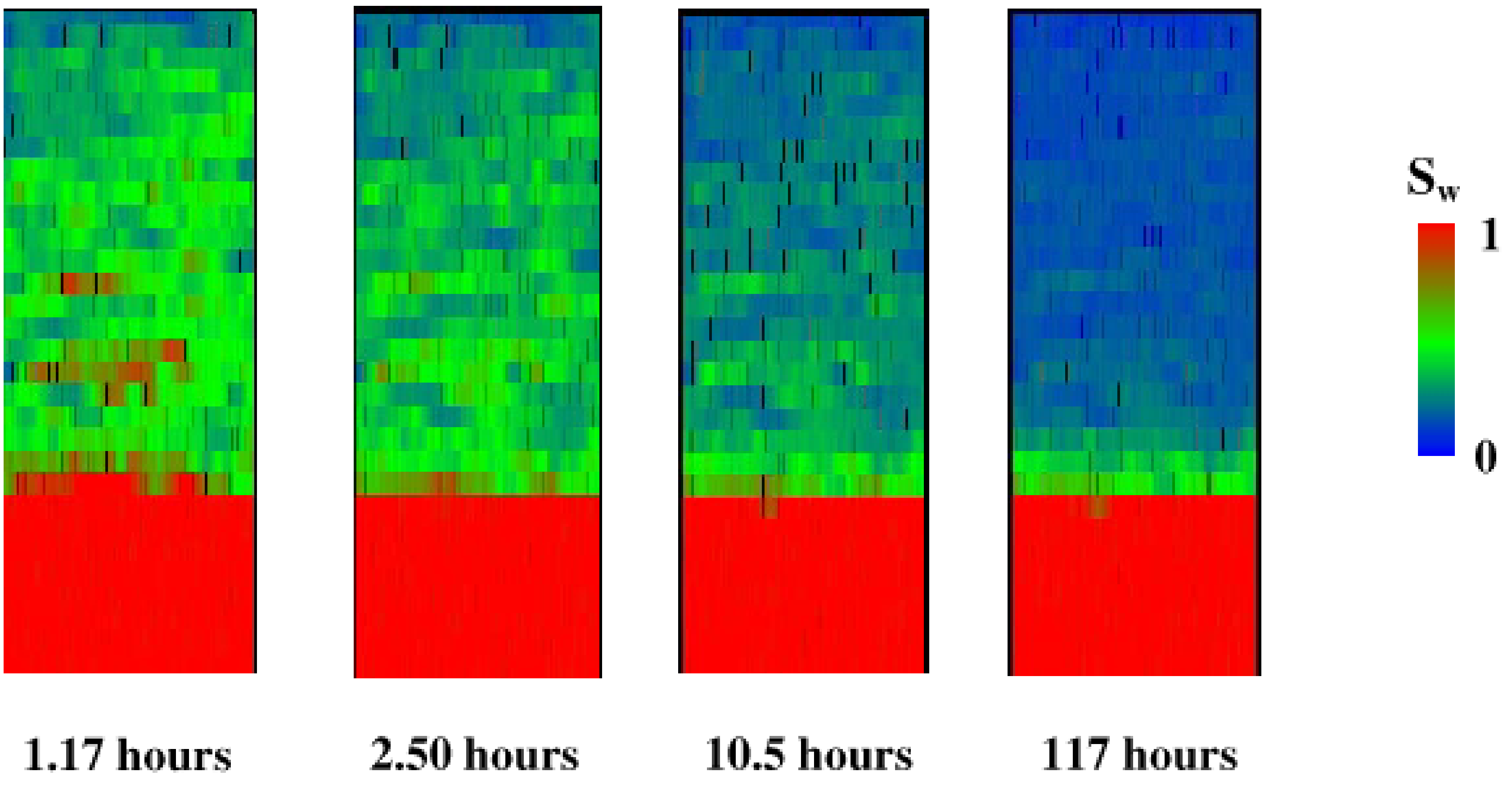
Water-wet. After gas injection.
$\theta_{ow} < 60^o$.
$\theta_{go} < 60^o$.

Mixed-wet.
$\theta_{ow} > 60^o$.
$\theta_{go} < 60^o$.

CT scanning


GRAVITY DRAINAGE EXPERIMENTS
POSITIONING SYSTEM
Scan Plain
3" DIAMETER CORE
3" x36" CORE

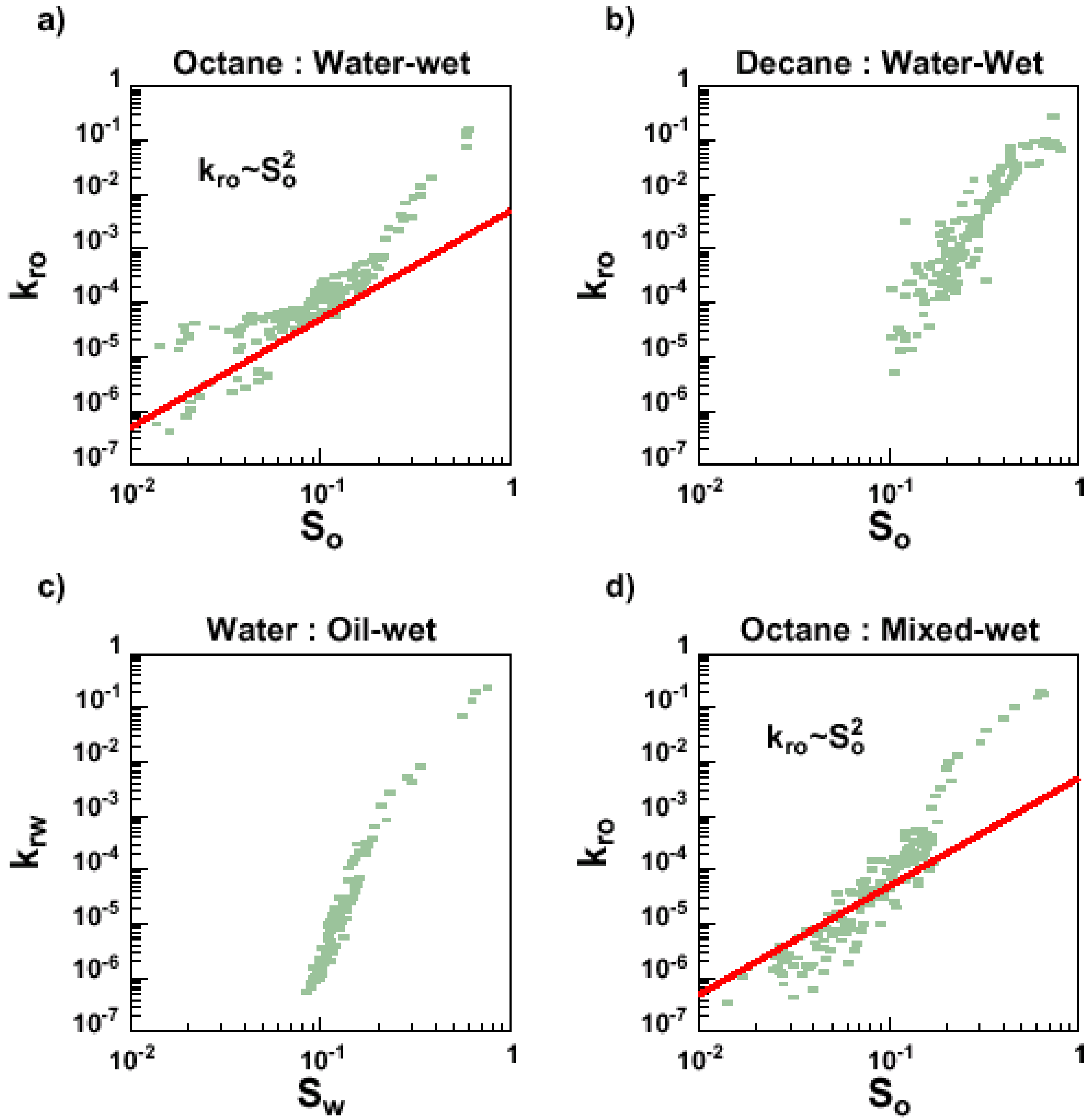
Measured water saturation



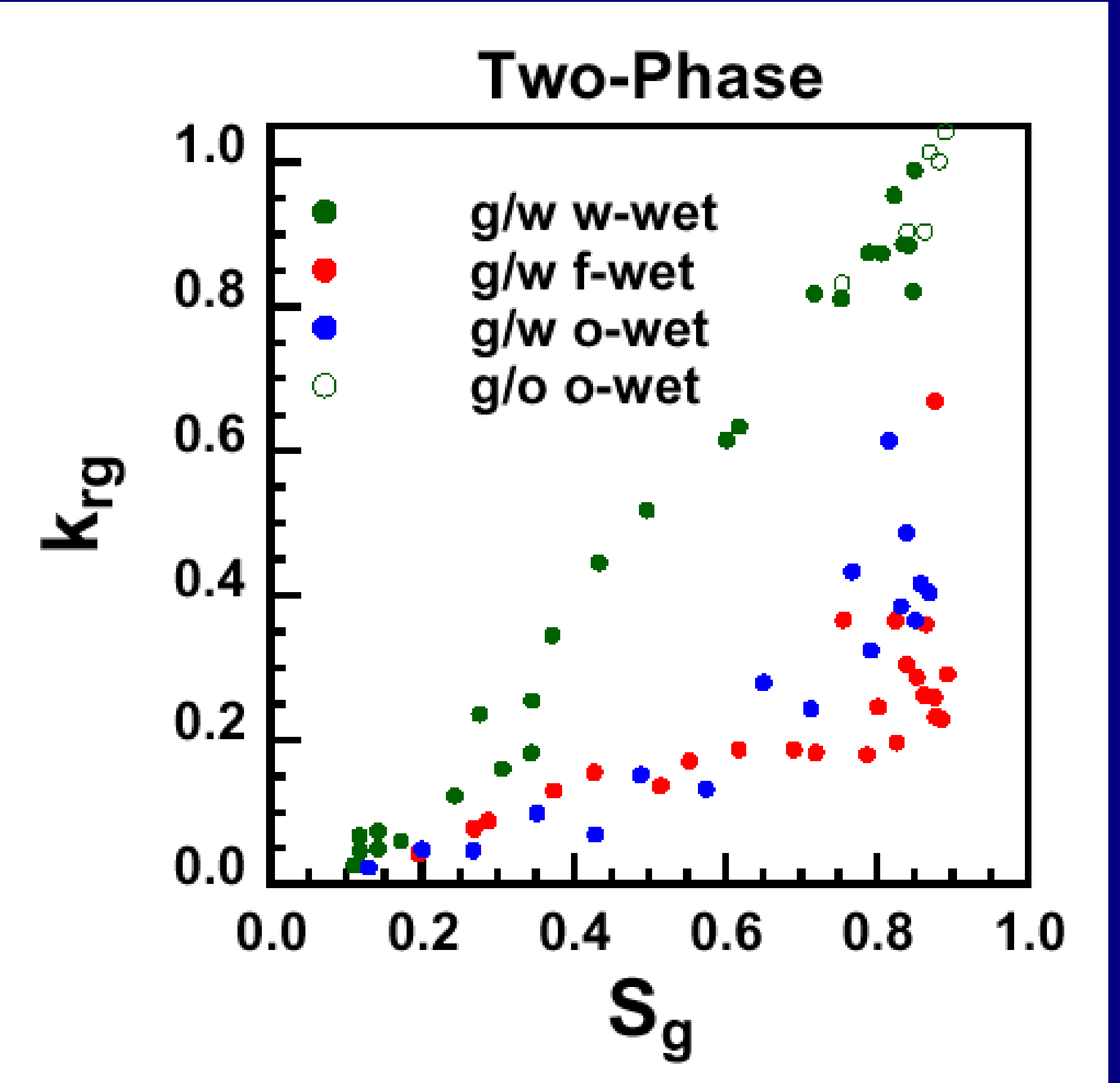
Layer drainage

Sand pack experiments

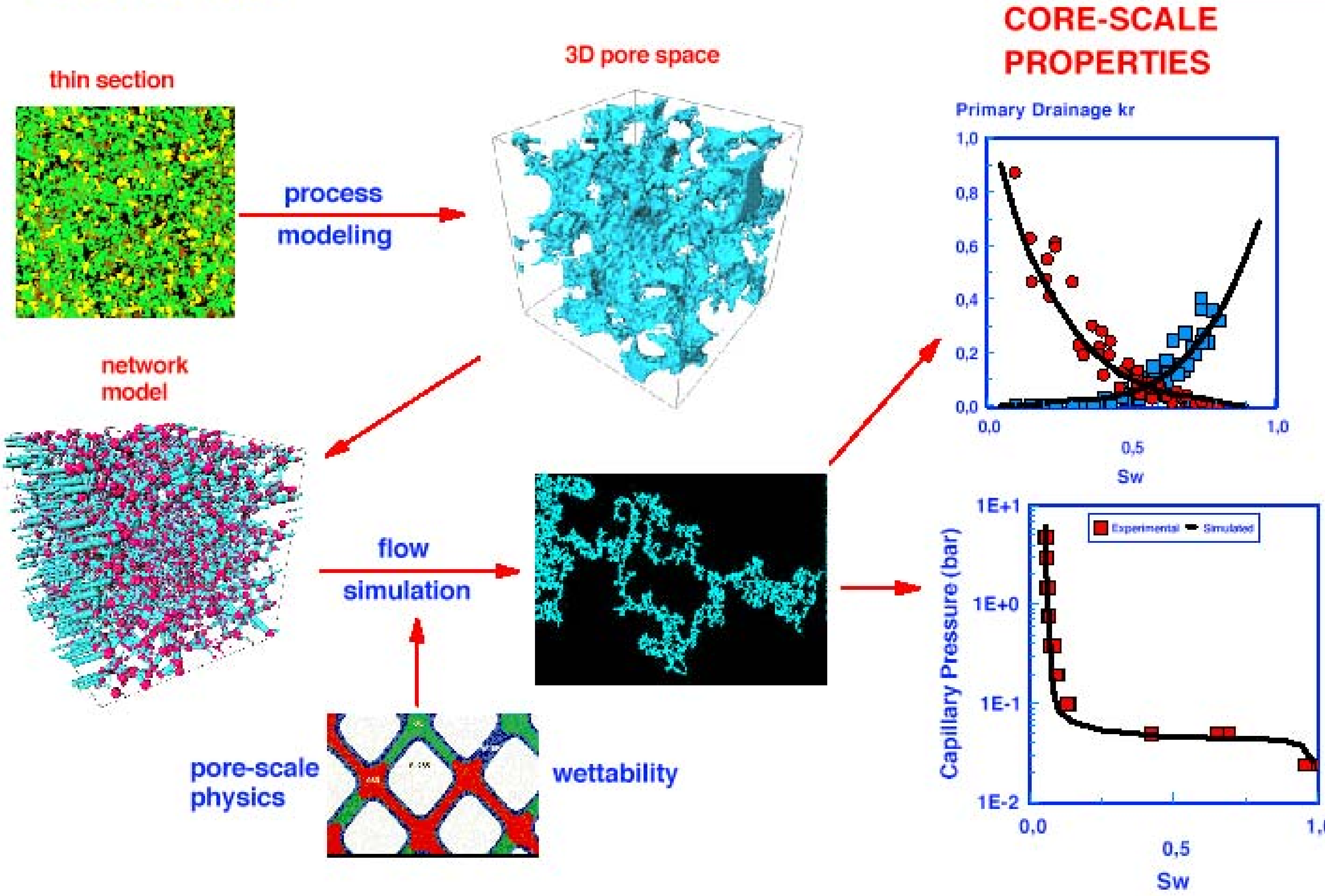
Measure relative permeability over six orders of magnitude



Gas relative permeability



Pore-to-Core


CORE-SCALE PROPERTIES
thin section
process
modeling
3D pore space
network model
flow
simulation
pore-scale physics
wettability
Primary Drainage kr
1,0
0,8
0,6
0,4
0,2
0,0
0,0
0,5
1,0
Sw
Capillary Pressure (bar)
1E+1
1E+0
1E-1
1E-2
Experimental
Simulated
0,0
0,5
1,0
Sw

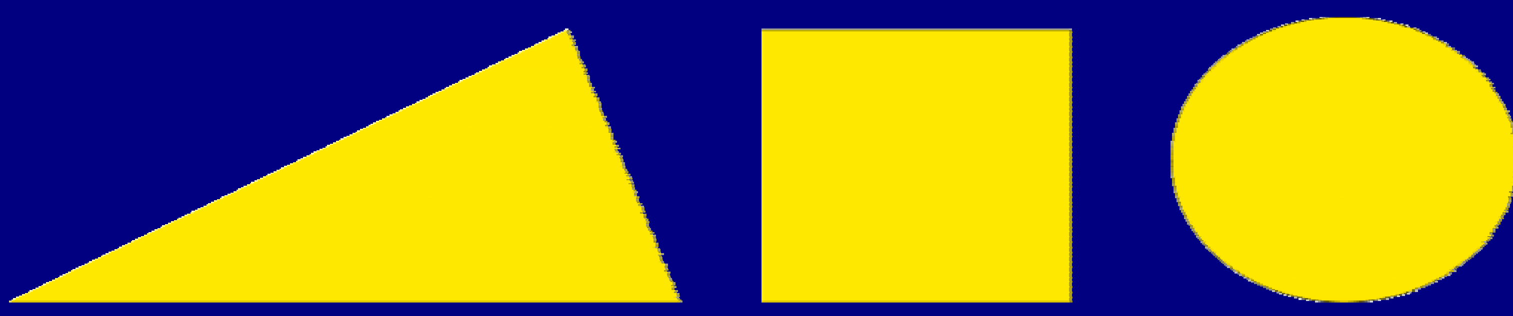
Our approach

- Detailed random geometry
  - Construct network from actual sandstone geometry
  - Obtain volume, connection number, pore size distribution from reconstruction process
- Detailed pore scale physics
  - Allow for wettability alteration after drainage
  - Flow in layers and corners

Pore and throat geometry

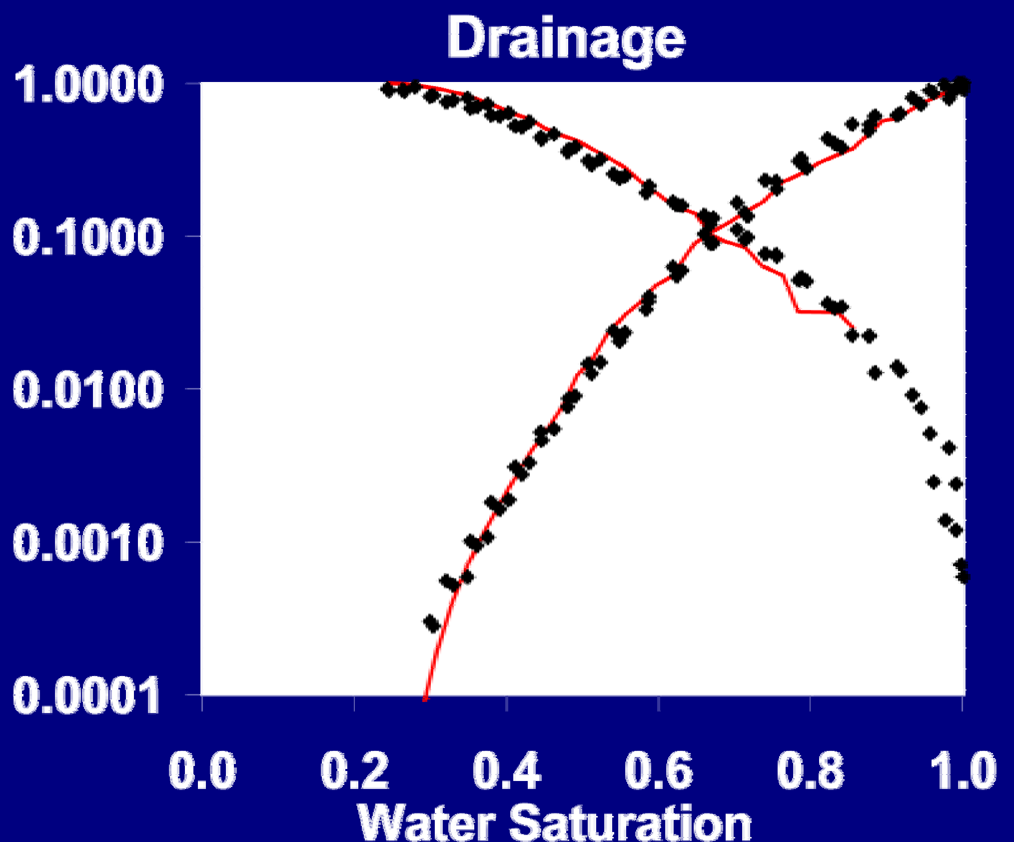
- Pores and throats have square, triangular or circular cross sections
  - Shape is defined in terms of shape factor G, obtained from reconstruction process

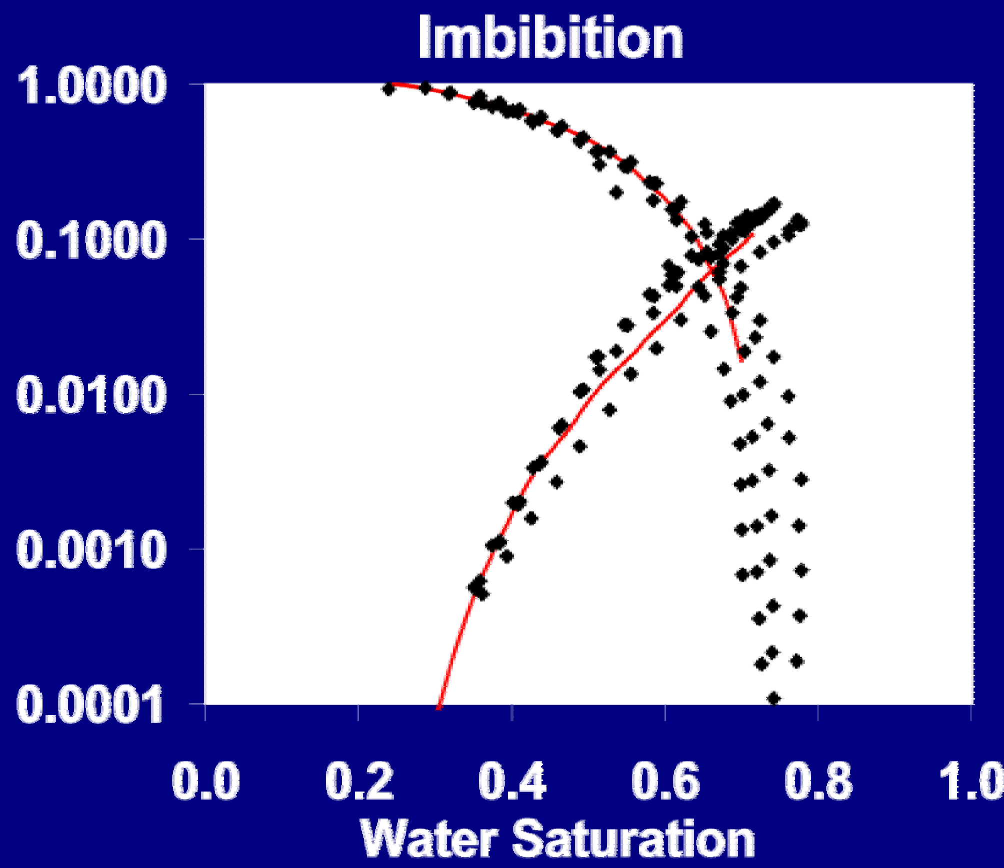
$$G = \frac{\text{Area}}{\text{Perimeter}^2}$$



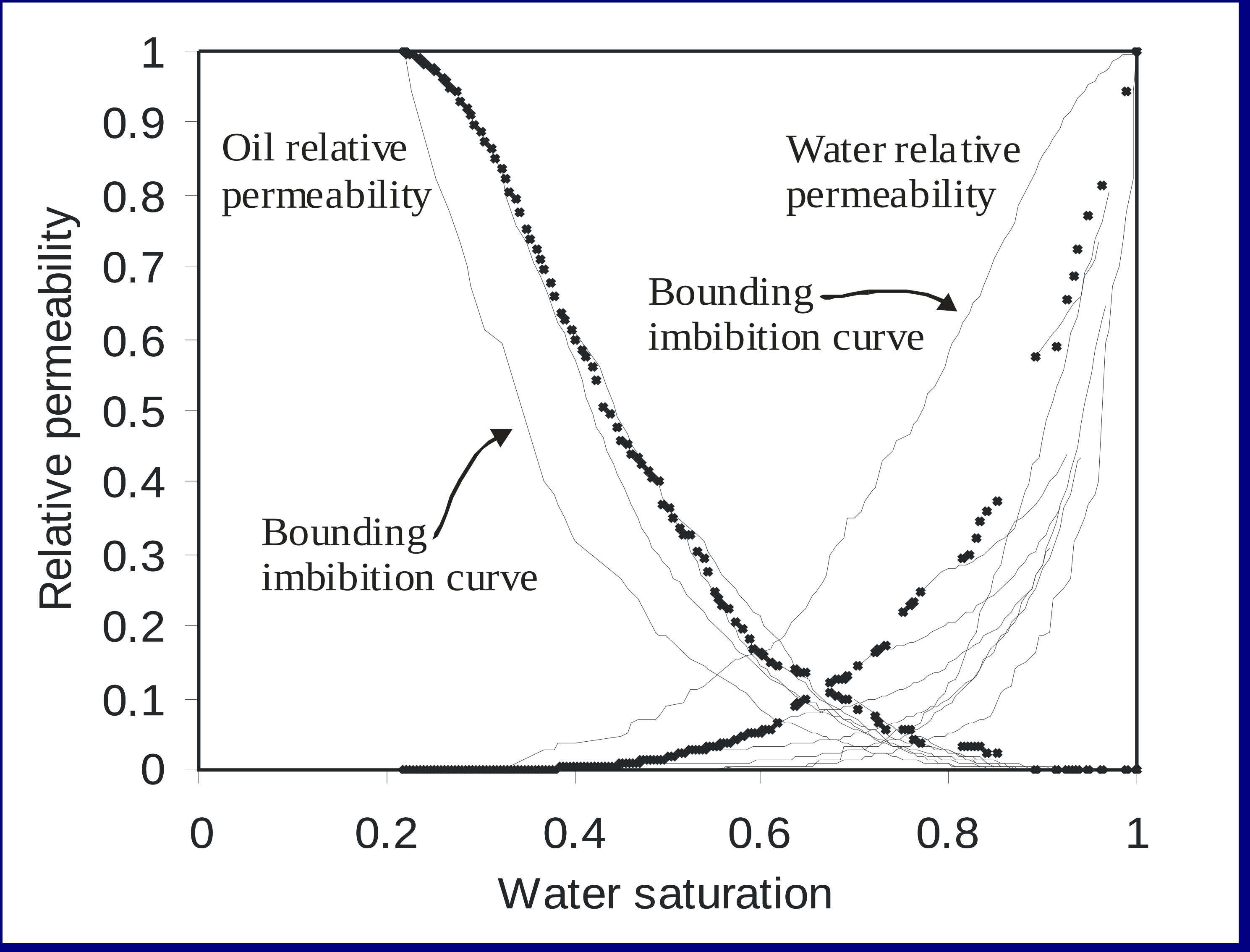
Berea sandstone example
(Oak SPE 20183)

- 0 degrees receding contact angle
- 30-90 degrees advancing contact angle (60°mean)

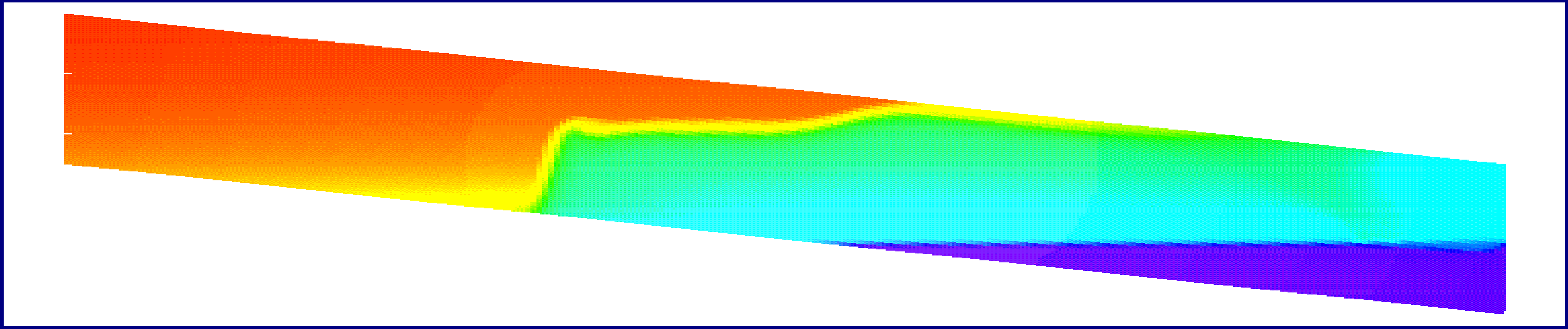




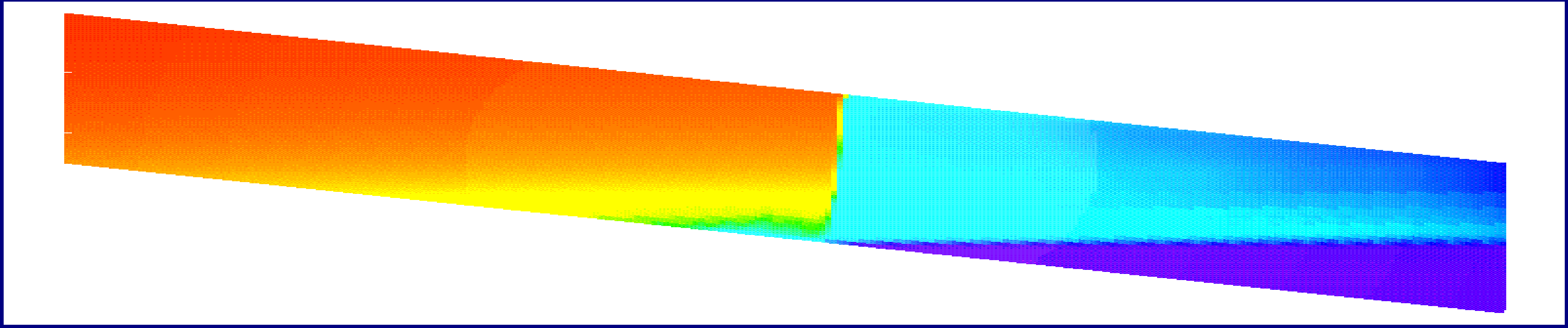
Hysteresis: Oil-wet



Macroscopic consequences

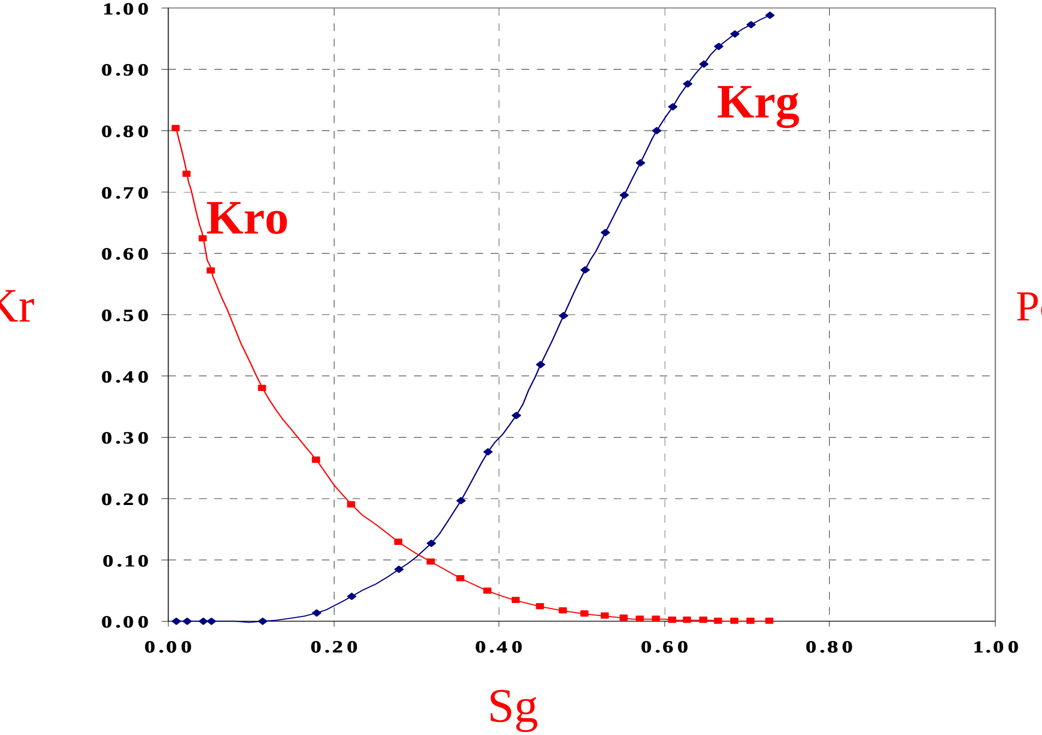


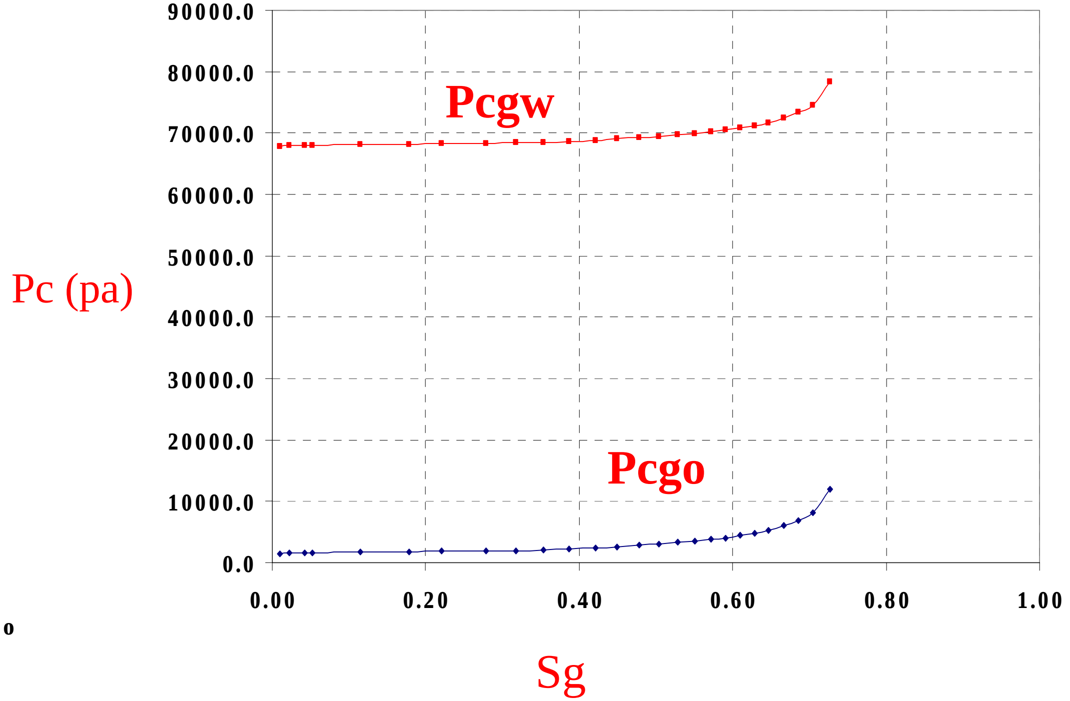
- Killough model of hysteresis – best current model for relative permeability



- Network model derived relative permeabilities. Much higher production

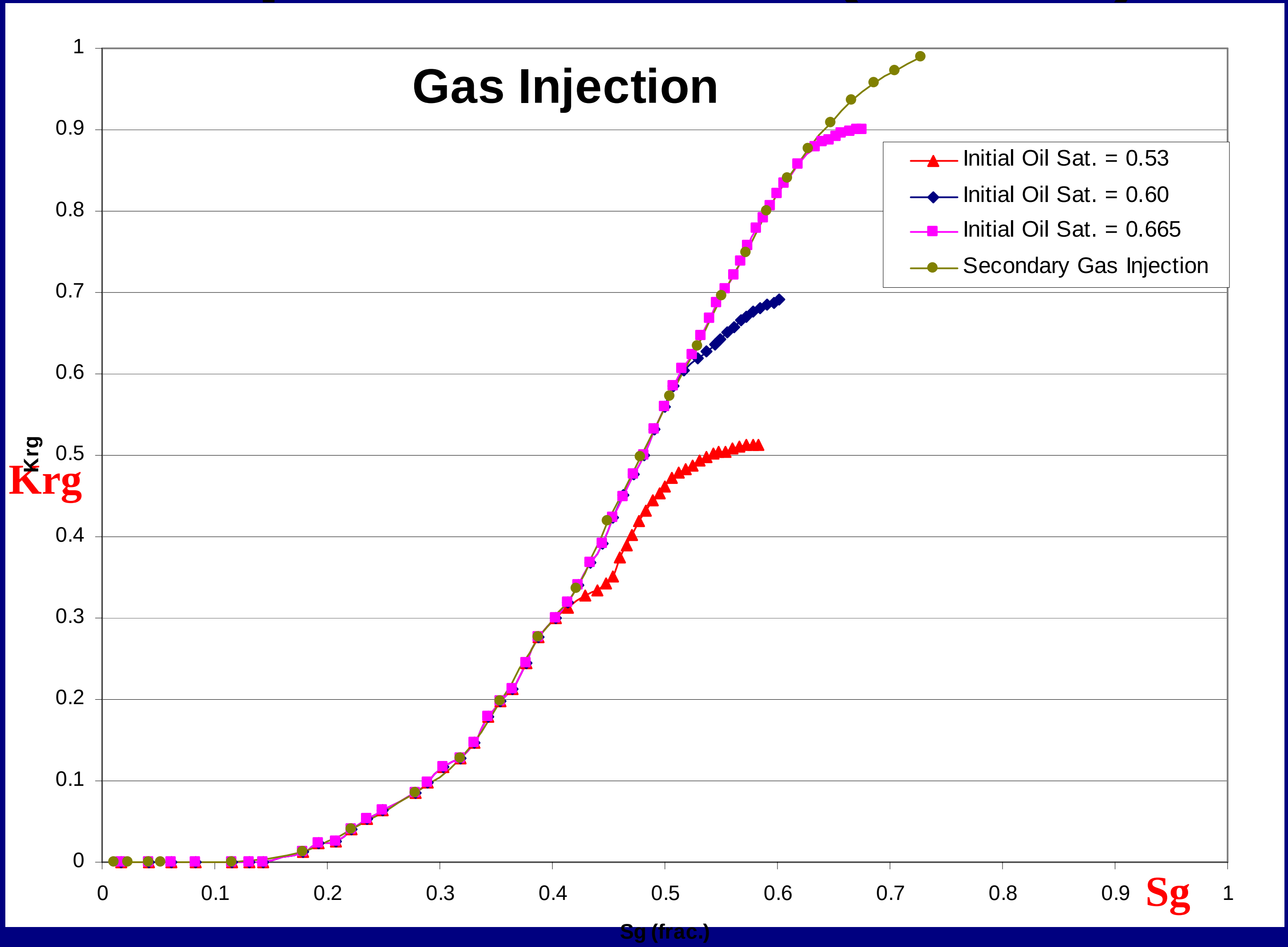
Three-phase results





Results for the Berea sandstone network for secondary gas injection

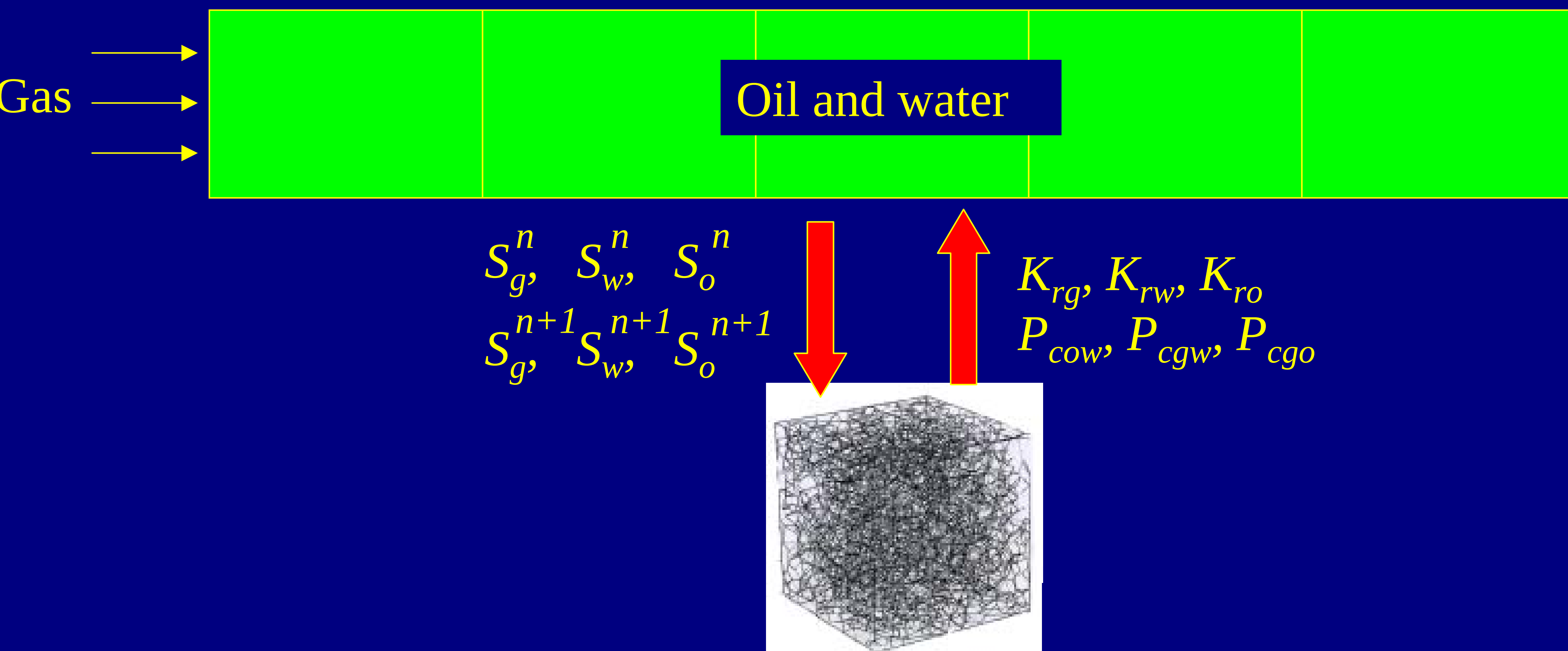
Three-phase results (contd.)



Effect of initial oil saturation on gas relative permeability

Self-consistency

Dynamic Pore to Core-Scale Simulation



Empirical three-phase model

- Base model - saturation-weighted interpolation for all three phases
- Layer drainage of oil
- Land-type model for oil and gas trapping
- Corrections for compositional consistency and near-miscible flow
- Data requirements: two-phase data (oil/water, gas/oil, gas/water) + $S_{or(w)}$ + $S_{gr(w)}$.

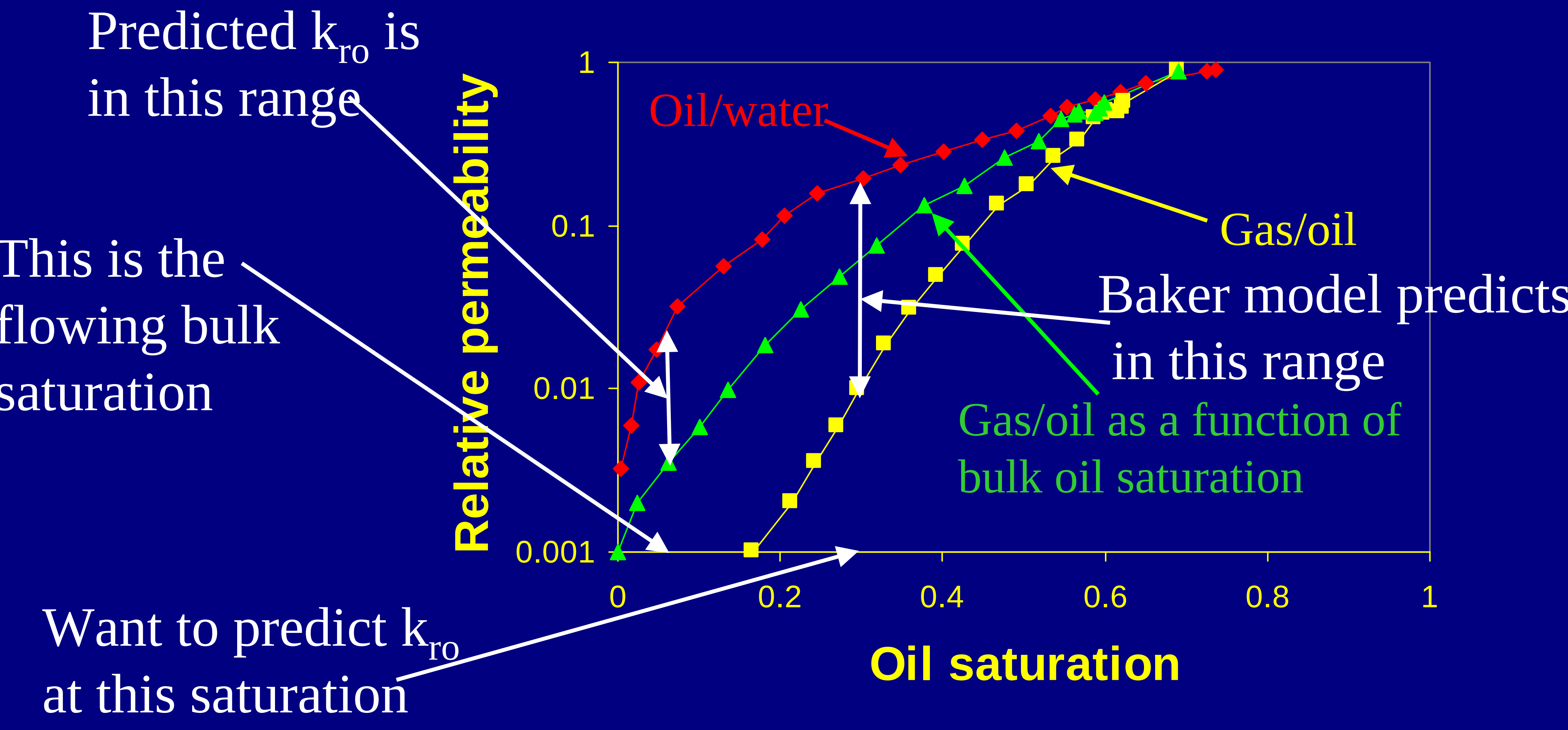
Trapping

- Tabulate data as a function of flowing (non-trapped) saturation. Assume relative permeabilities are unique functions of flowing saturation (Carlson).
- Use a Land-type (or other) model to predict the amount of trapping as a function of the maximum saturation reached.
- Can account for any displacement sequence and for trapping of oil, water and gas.
- Find a *flowing* phase saturation, and to compute the relative permeabilities as functions of this flowing saturation.

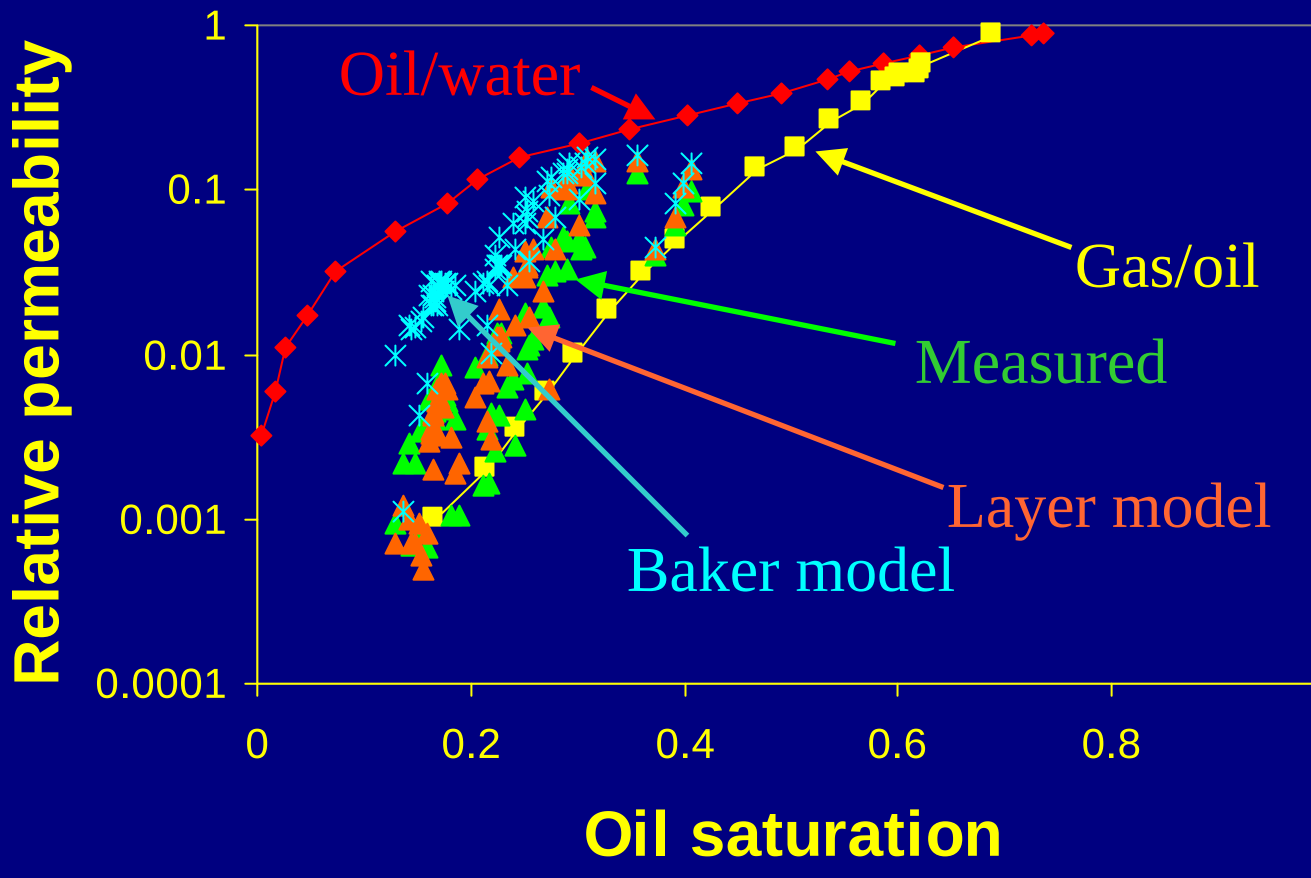
Testing the model

- Steady-state three-phase data for water-wet Berea from Oak and co-workers at Amoco.
- Thanks to Gary Jerauld and Peter Salino (bp) for providing raw data.
- Particularly challenging – huge difference between oil/water and gas/oil curves.
- Will predict oil relative permeability and test the layer model with trapping.

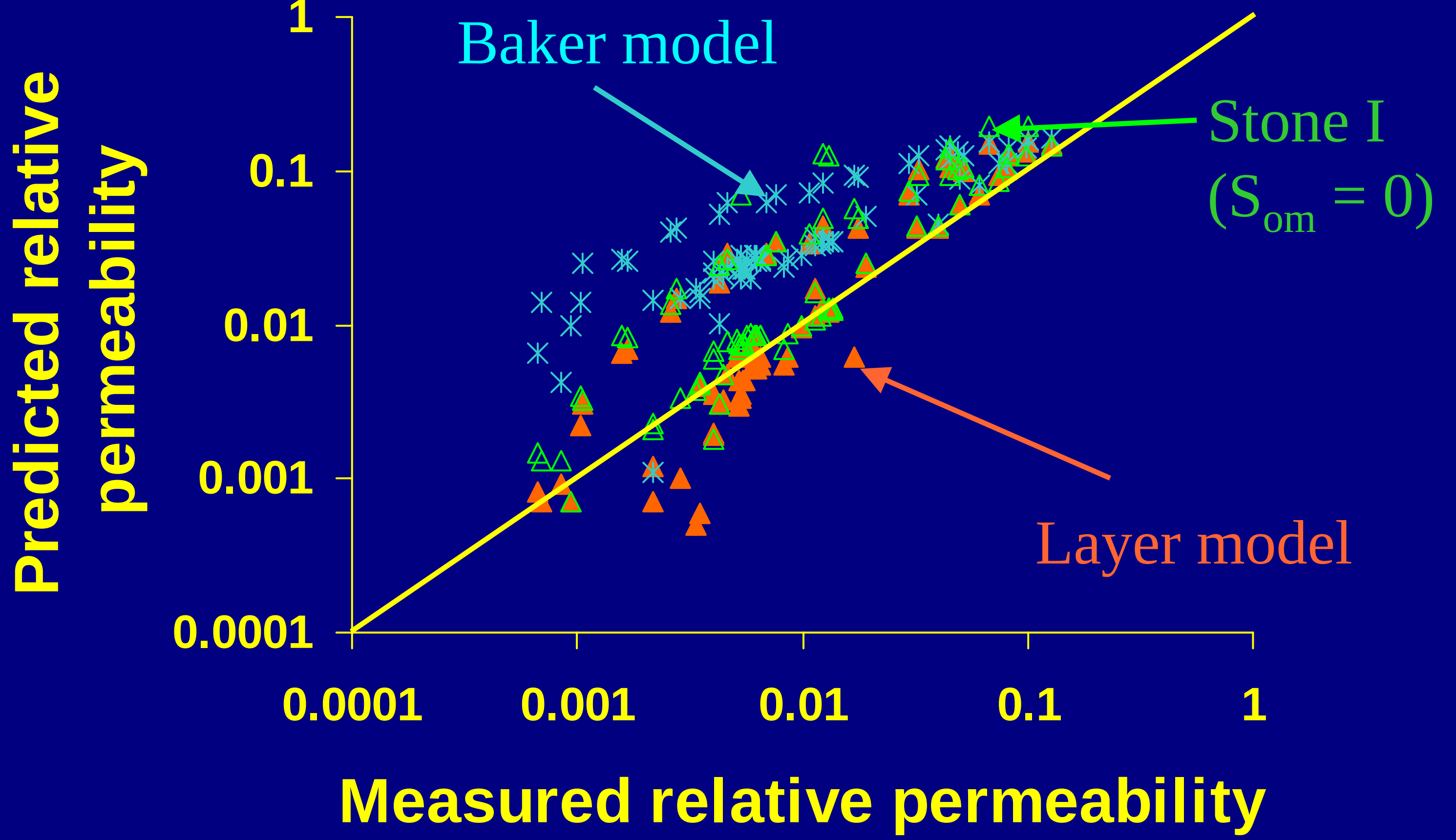
How we find the oil relative permeability from the data



Predicted and measured oil relative permeabilities (Oak data)



Predicted and measured oil relative permeabilities



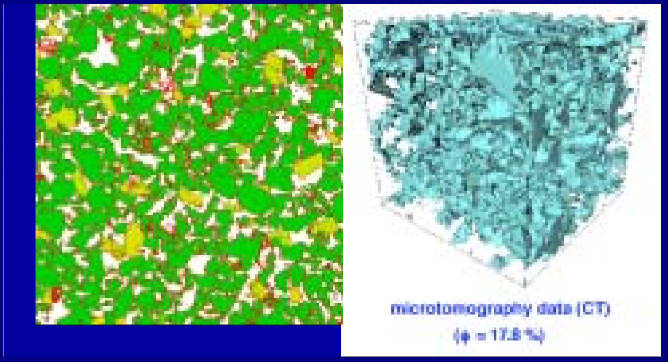
Future directions

- What is needed to predict relative permeability? Issues of pore-space geometry and wettability
- Further three-phase work
- Use the pore-scale model as a platform for other studies: non-Newtonian flows, rate effects etc.
- What if we *are* truly predictive?

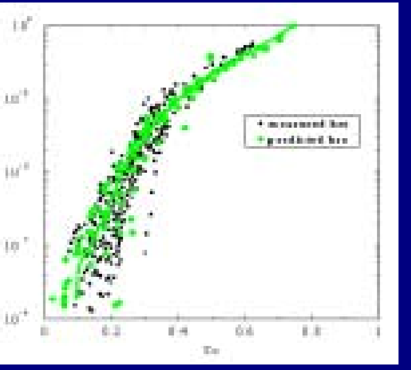
Reservoir characterization

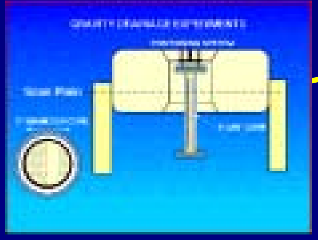
- **Populate detailed reservoir models with physically valid relative permeability curves**
- **Account for trends in the reservoir**
  - Different networks depending on facies
  - Variation in porosity and/or permeability
  - Changes in wettability
- **Couple dynamically with larger-scale simulation**

Pore-to-core-to-reservoir simulation



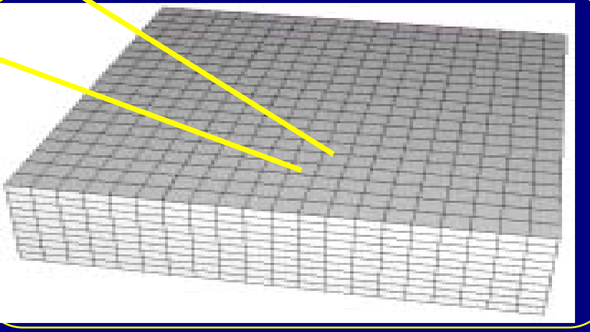
Pore-scale modelling





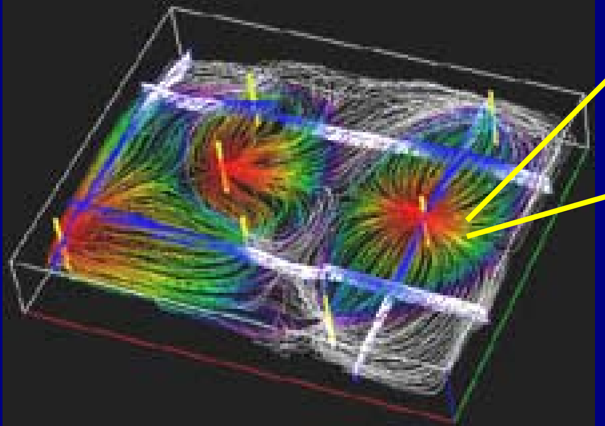
Core scale

10 – 100 m



Experiments

Field scale - streamlines



Reservoir grid block scale - conventional simulation

Conclusions

- Presented a pore-scale scenario and network model for three-phase flow.
- Showed how CT scanning measurements of three-phase relative permeabilities can be interpreted using pore-scale physics.
- Discussed work on an empirical model of three-phase relative permeability that included effects of layer flow and hysteresis.
- Presented a dynamic upscaling approach, where effective properties are computed directly from a smaller-scale simulation.