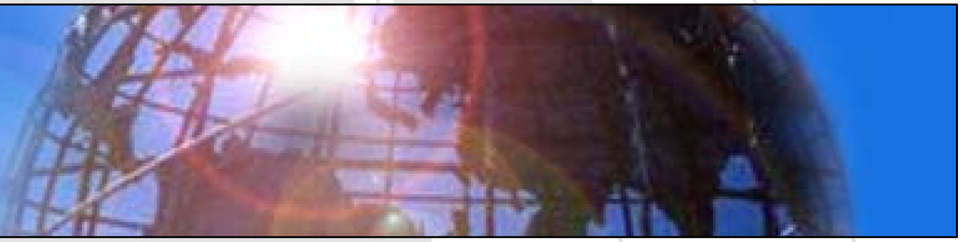
GCEP

Stanford University

Global Climate & Energy Project

GCEP Symposium
June 13, 2005



Predicting Flow Behavior for Geologic Storage of CO_2

Lynn Orr
Department of Petroleum Engineering
Stanford University

Key Questions for Flow Prediction

- How far does injected CO_2 propagate (where will we need to monitor)?
- How long does it take to immobilize the CO_2 by some mechanism?
- What fraction of the CO_2 has the potential to escape (as a function of time)?
- What modeling approaches are appropriate?

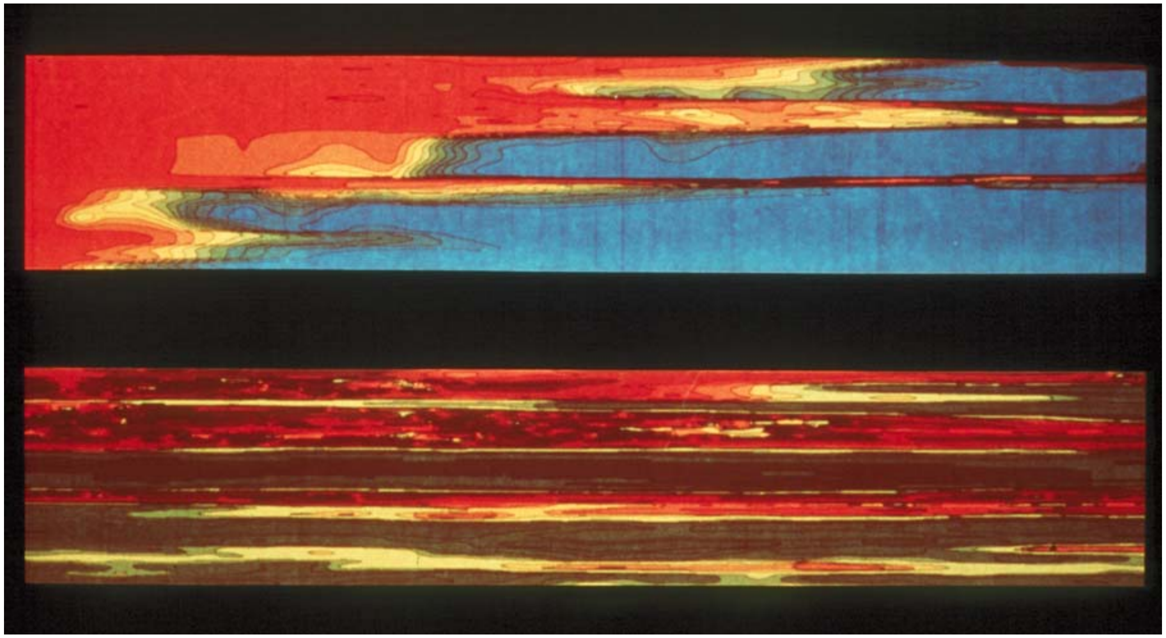
Models used should be based on an understanding of the relevant physics – the length and time scales of the flow and storage processes.

Multiple Time Scales for Various Storage Settings

- Convection – the injection period (or the time for flow between wells if there are production wells).
- Gravity relaxation – redistribution of fluids in reservoir after injection ceases.
- Capillary trapping of CO_2 by imbibition of brine.
- Dissolution in water or oil (aided by unstable convection?).
- Adsorption of CO_2 on solid coal surfaces.
- Chemical reactions of dissolved CO_2 with minerals present.

Key task: Make quantitatively reasonable estimates of all these time scales for realistic storage settings.

The Injection Period



CO$_2$ saturation

Permeability distribution

- Heterogeneity and gravity strongly influence the flow path.
- Extremes of permeability determine the flow paths.
- Low viscosity CO$_2$ will find the easy flow paths between wells. CO$_2$ is an order of magnitude less viscous than brine or oil. It is slightly more viscous than natural gas.

Flow Prediction for the Injection Period

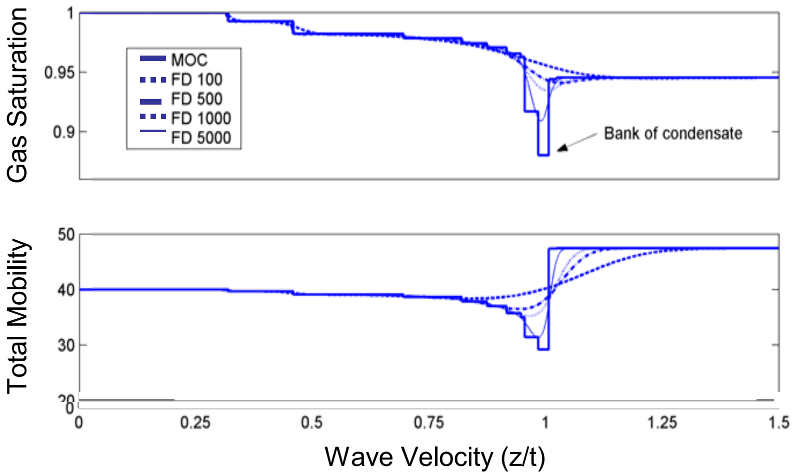
- If permeability variation and gravity dominate flow behavior, sufficient resolution to define probable flow paths will be required.
- If composition variations strongly affect flow behavior (they do in oil and gas settings, but they are less important in aquifers), then a sufficient number of components is also required.
- Conventional finite-difference representations are often too slow to allow high resolution (spatial or compositional) for field-scale simulations.
- Streamline methods offer a way to improve speed and therefore, resolution.

Streamline Methods for Flow Prediction

- CO_2 storage processes are inherently compositional (components move between phases).
- Conventional finite-difference compositional simulation methods are slow and badly affected by numerical dispersion.
- Use streamlines to capture effects of heterogeneity – high resolution is required to represent effects of high and low perm flow paths.
- Propagate 1D solution along streamlines to account for component transfers between phases (can use analytical solutions or numerical solutions here).
- Update streamlines occasionally to account for changing mobilities.

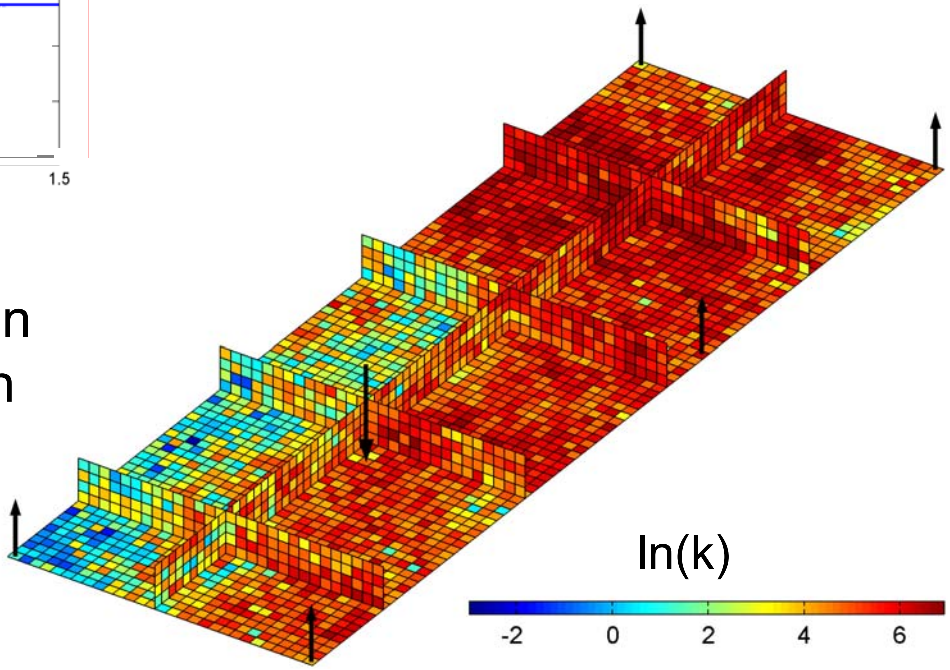
Streamlines are the method of choice for compositional processes during the injection period. They are fast and accurate. They are not appropriate for periods long after injection ceases.

Example: CO_2 Storage in a Gas Reservoir containing Condensate



Numerical dispersion prevents finite-difference methods from resolving the condensate bank, except at very high grid resolution, even in 1D.

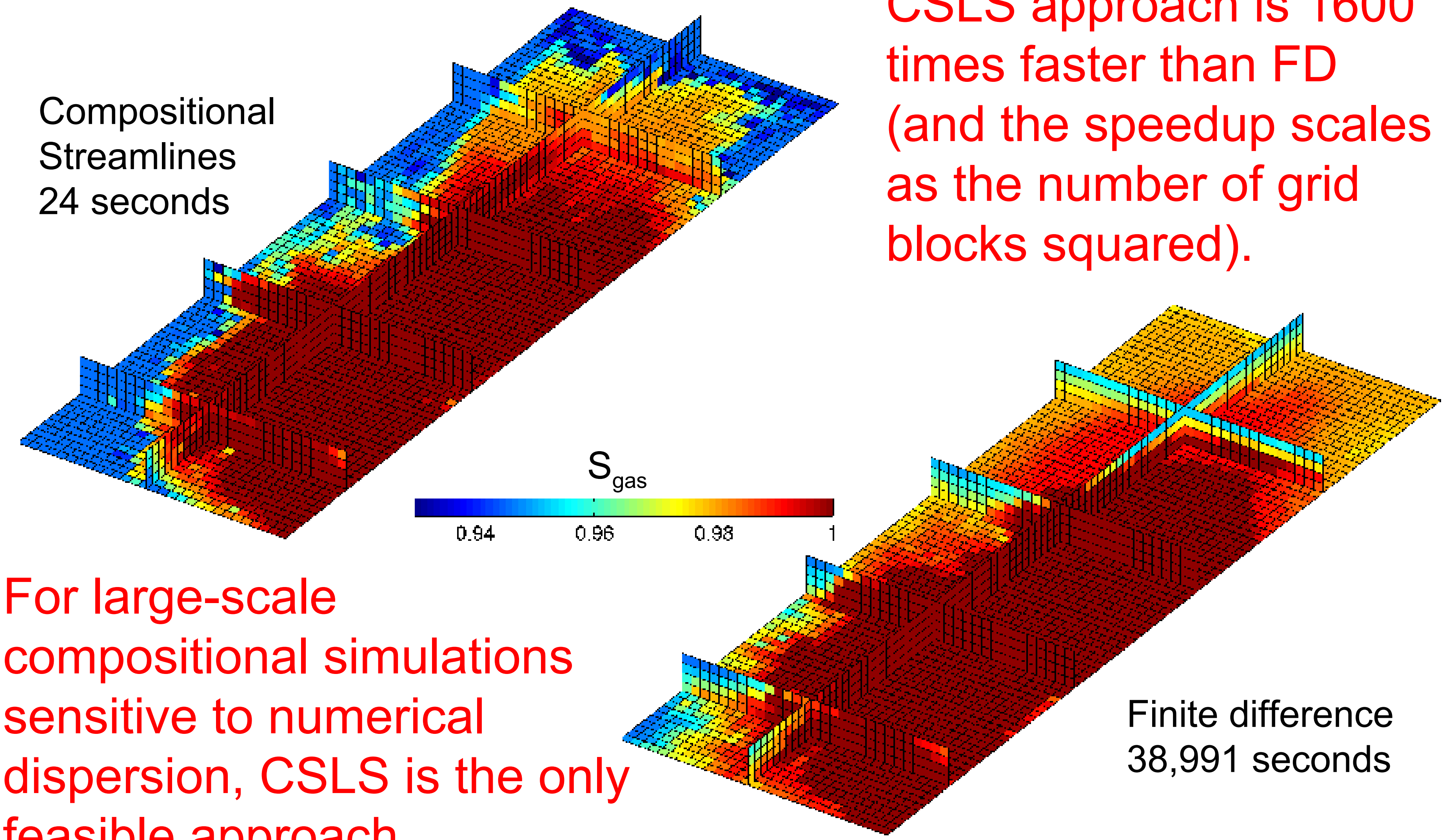
13 component fluid description (35% H_2S), pure CO_2 injection



Heterogeneous permeability field,
30 × 90 × 5 = 13,500 grid blocks

S_{gas} after 2500 Days Injection

CSLS approach is 1600 times faster than FD (and the speedup scales as the number of grid blocks squared).

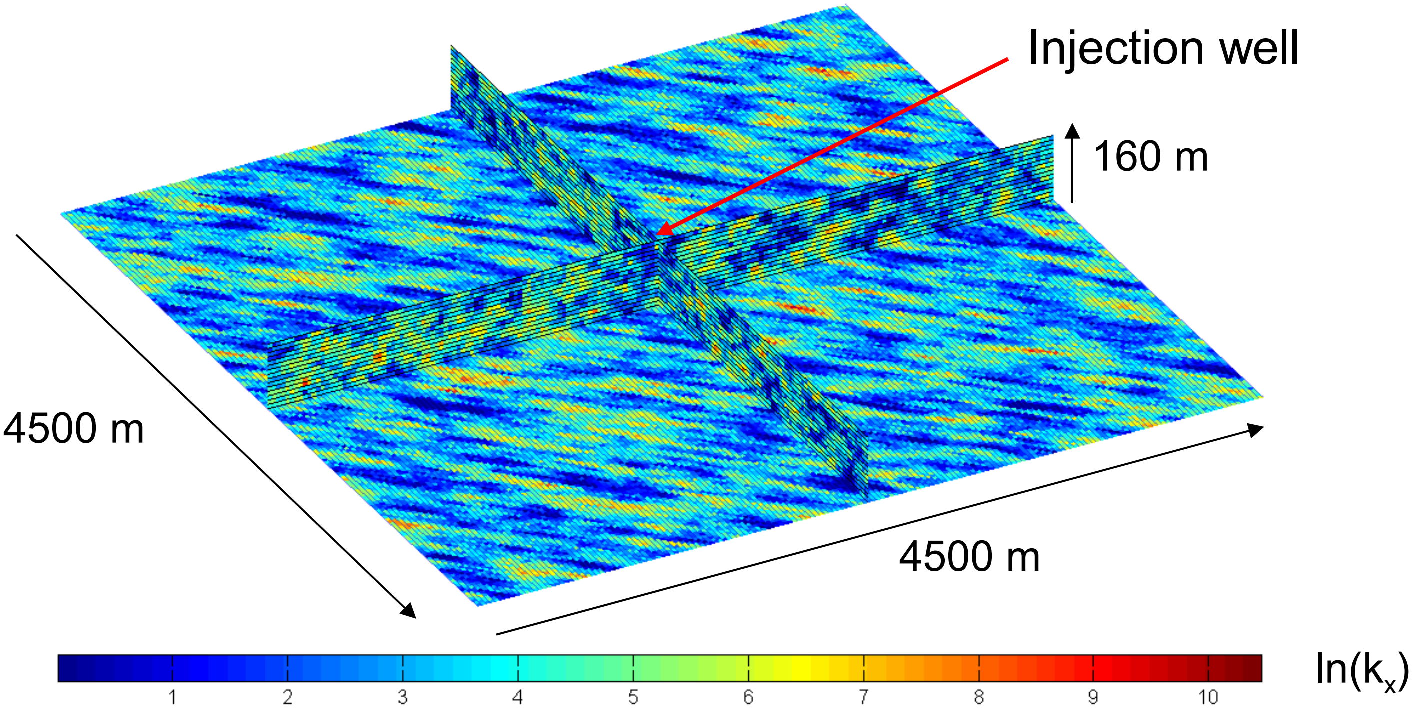


Compositional Streamlines
24 seconds

Finite difference
38,991 seconds

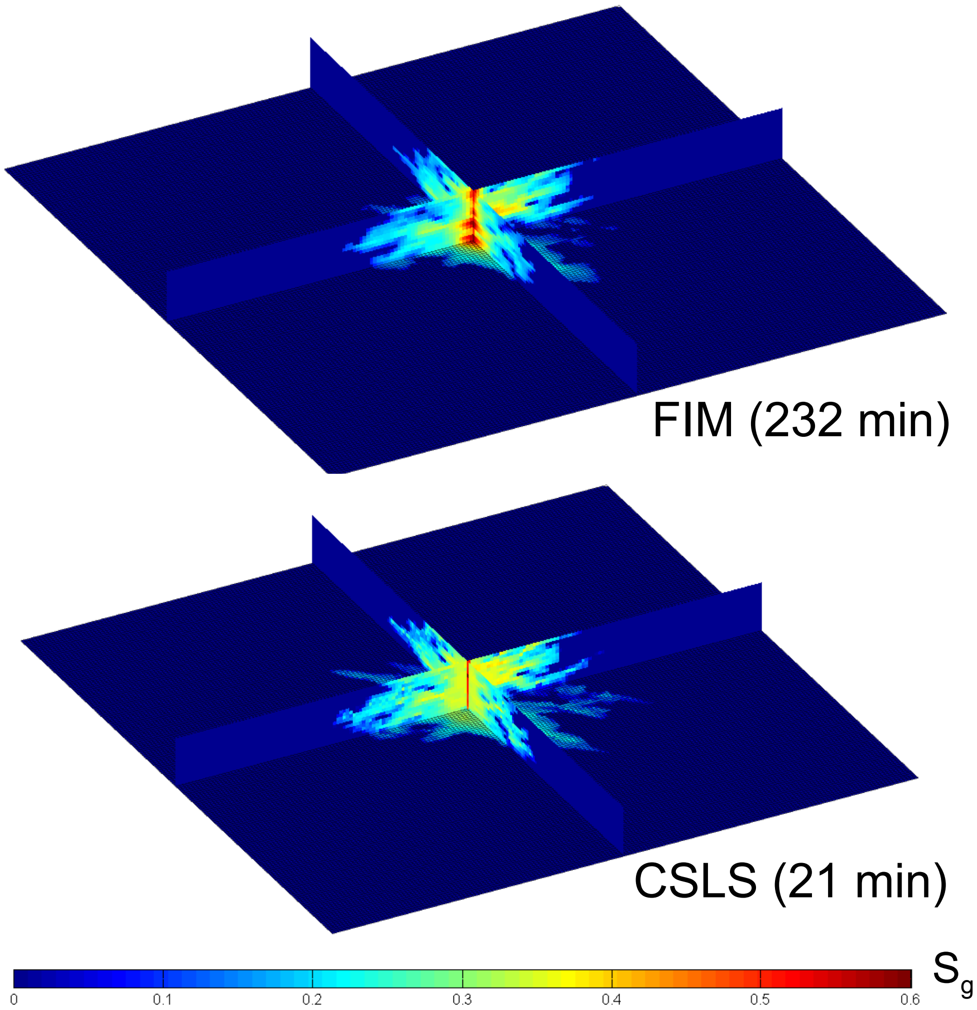
For large-scale compositional simulations sensitive to numerical dispersion, CSLS is the only feasible approach.

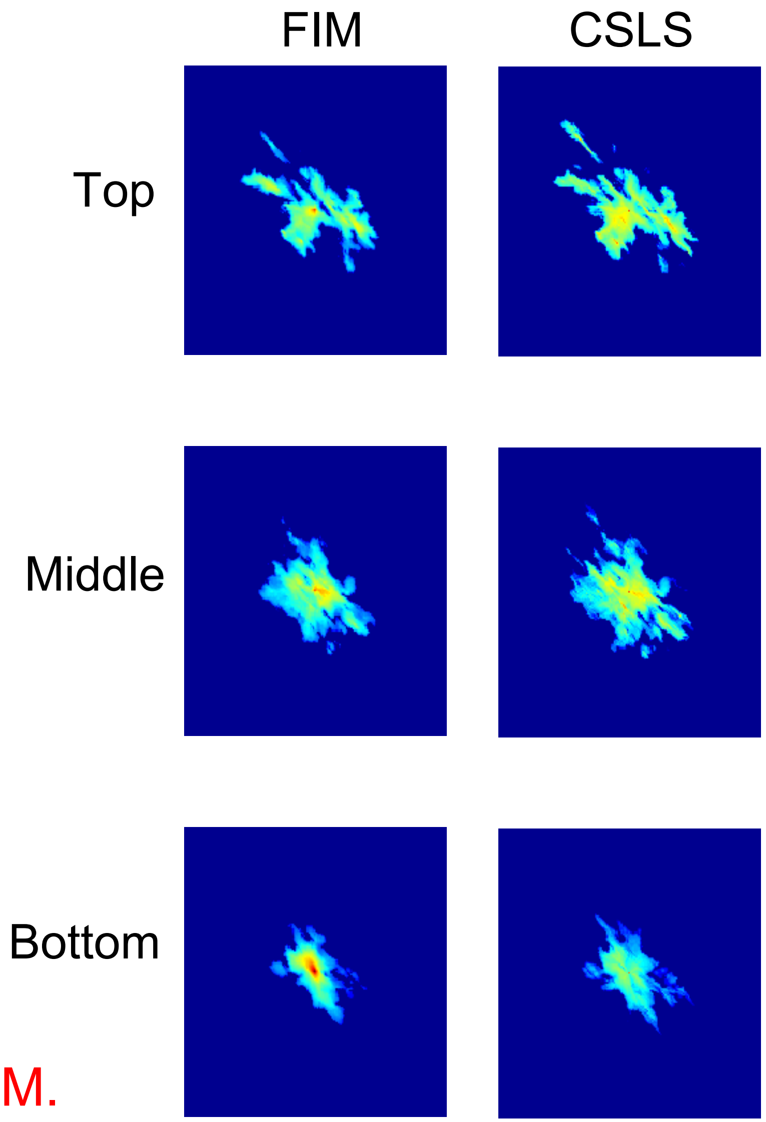
Aquifer Injection with Gravity, Heterogeneity, and Solubility



- Grid resolution: 180 x 180 x 16 = 518,400 grid blocks
- Compare simulations of a fully implicit “black oil” simulator (FIM) with compositional streamline calculations (CSLS.

Calculated Flow Behavior with FIM and CSLS





CLSL an order of magnitude faster than FIM.

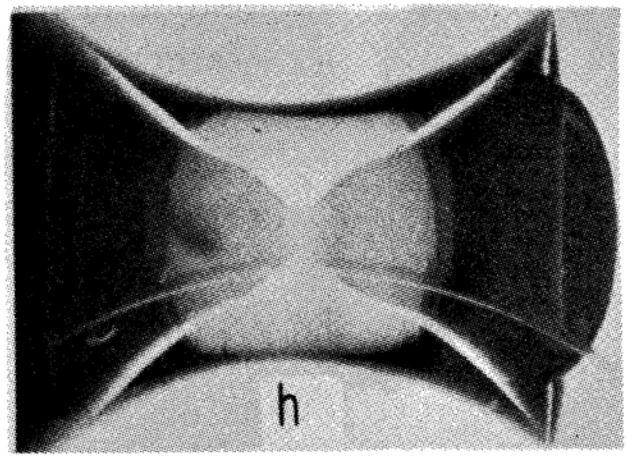
What Happens after Injection Ceases?

- The streamline approach offers an efficient way to predict flow behavior during the convection-dominated injection period.
- Streamlines are probably not the right approach for subsequent periods, when gravity relaxation, capillary trapping, dissolution, and reaction operate.
- Consider next the time scales for gravity relaxation, capillary trapping, and dissolution.

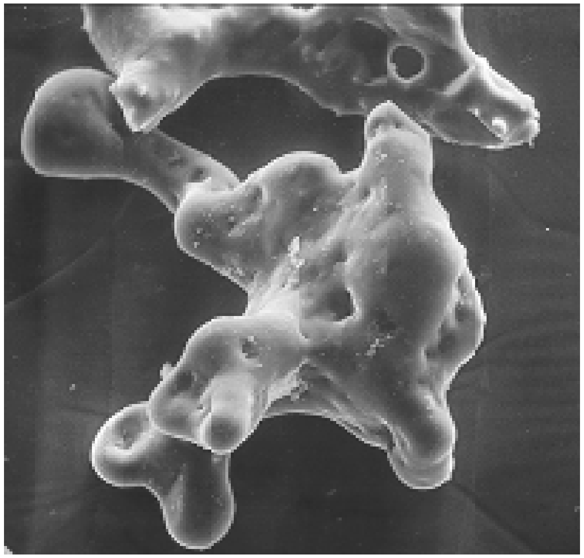
Capillary Trapping of a Nonwetting Phase

- Capillary trapping has been well studied, because it creates residual oil to waterflooding.
- When the saturation of the nonwetting phase declines (as will happen due to dissolution of CO_2 and gravity relaxation), bubbles of CO_2 will snap off and trap.

Capillary pressure differences (due to curved interfaces in pores with high aspect ratio) create unstable interface configurations. A neck of wetting phase snaps off bubbles. After snap-off, bubbles are immobile.

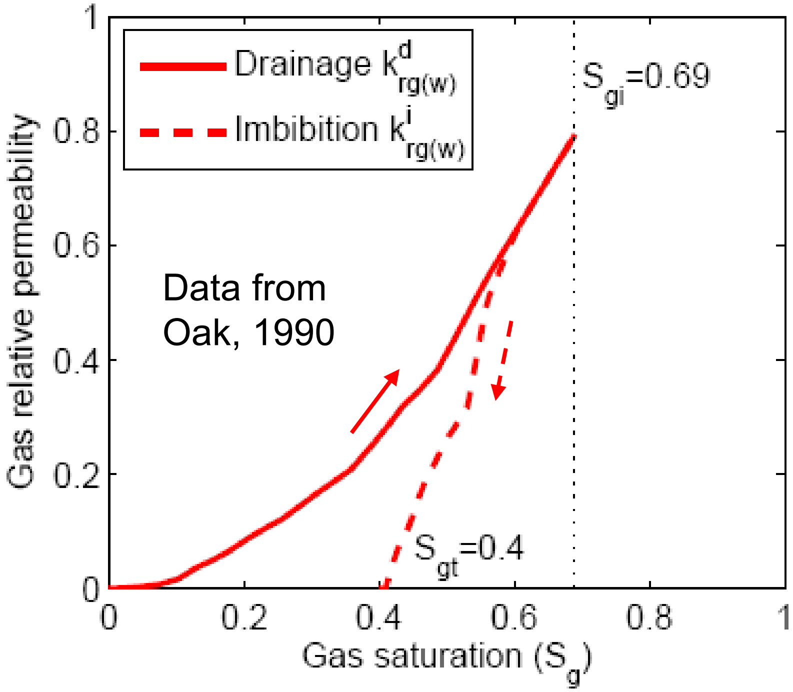


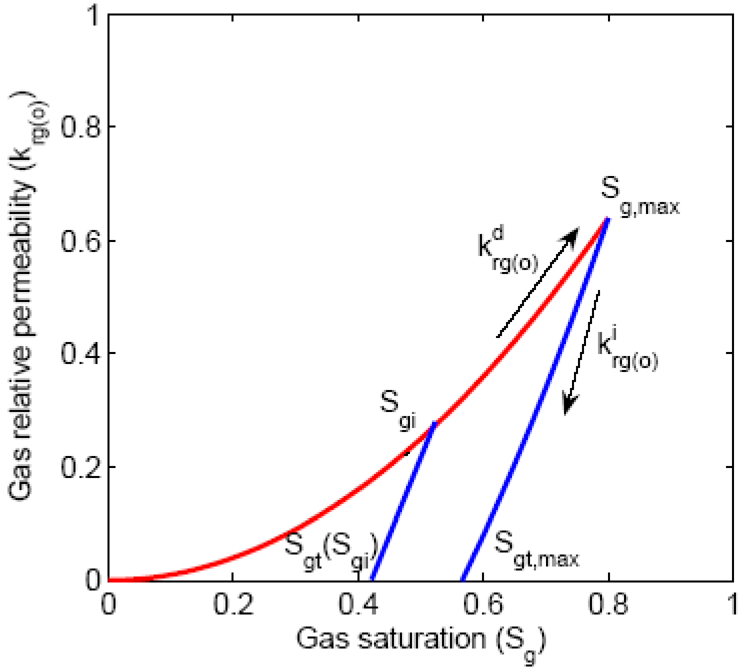
Snap-off (Source: Roof, SPEJ, 1970)



Residual nonwetting phase
(Image: N. R. Morrow)

Capillary Trapping and Relative Permeability

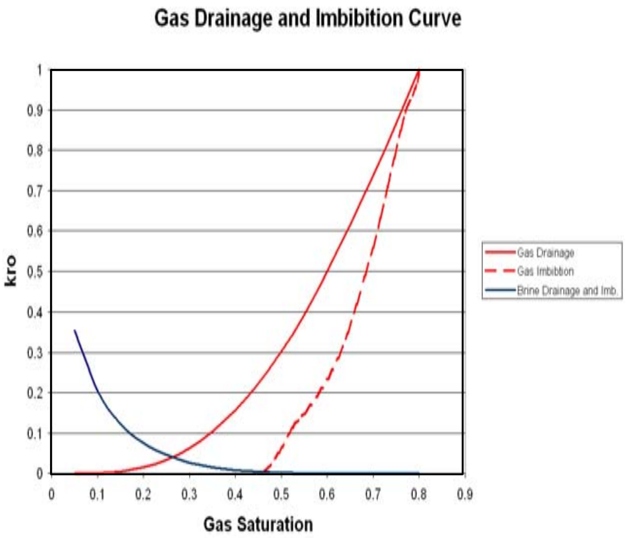


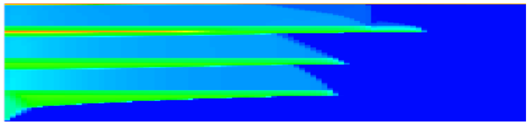


In water-wet systems, significant fractions of the CO_2 will trap as a residual phase when gas saturations start to decline. The trapped gas saturation depends on $S_{g,max}$.

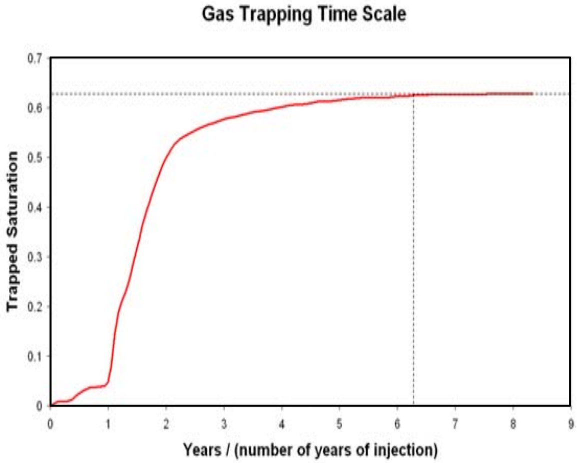
Source: E. Spiteri MS Report, Stanford U., 2005, from data of Oak, JPT, 1990

What happens after injection ceases: effect of capillary trapping of residual CO_2





End of CO_2 Injection



Hysteresis

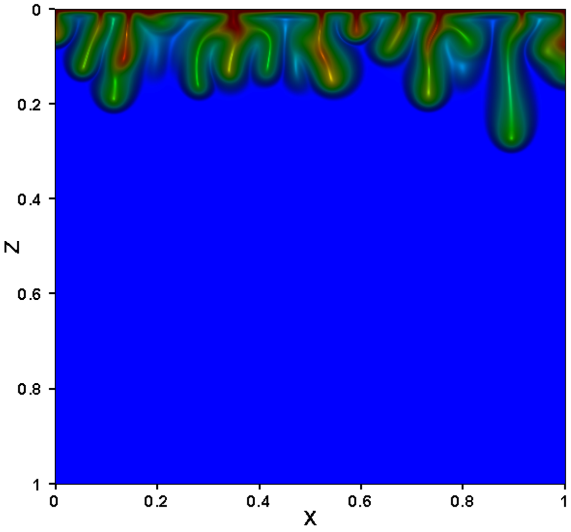
No Hysteresis

5 years

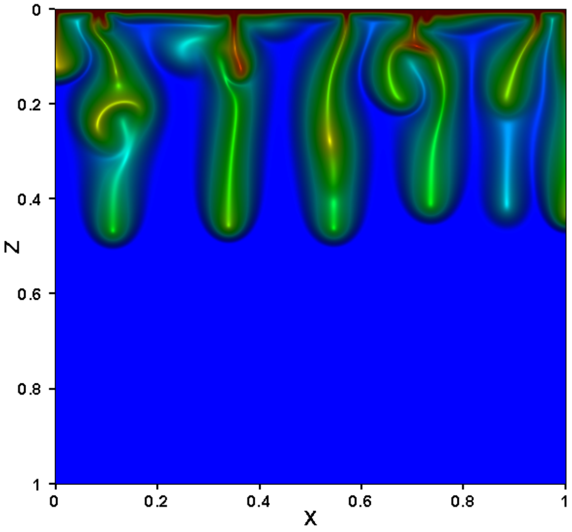
50 years

For this example, significant capillary trapping happens during the gravity relaxation period, and it happens on ~ the injection time scale.

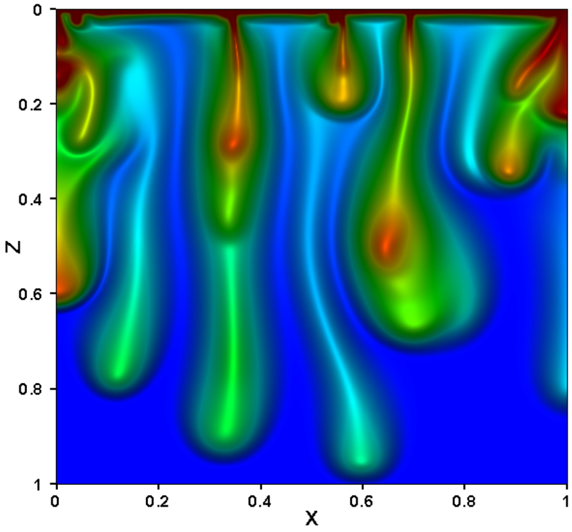
Dissolution of CO_2 in Brine



24 years



52 years



108 years

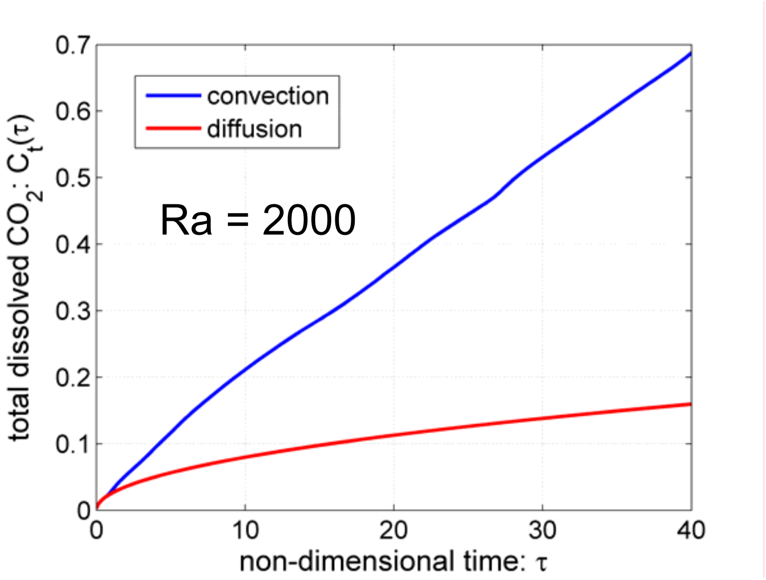
- Diffusion of CO_2 into brine creates more dense brine at the upper interface.
- That configuration is unstable, and gravity-driven fingers develop (but the fingers move slowly).

Conventional reservoir simulations do not resolve these fingers well enough to give accurate estimates of transport rates.

Source: A. Riaz, M. Hesse, H. Tchelepi, Stanford University, 2005

Time Scales for Dissolution

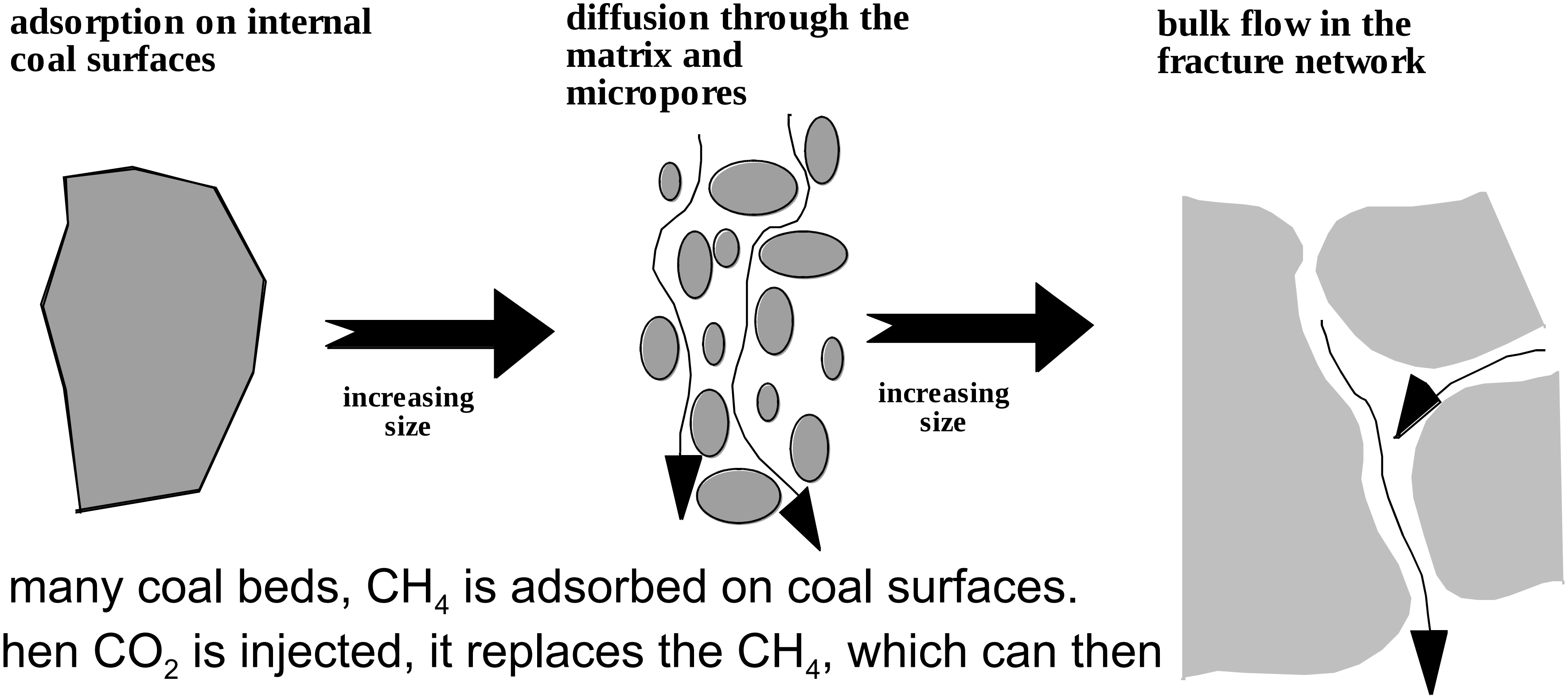
- Linear stability theory and high-order numerical simulation show three time scales
  - Onset of fingering is diffusion-controlled (t_{on})
  - Convection significantly increases dissolution rate after onset
  - When fingers reach the bottom of the aquifer, the rate slows (t_{slow})
  - The time to saturate (t_{sat}) all the brine is much longer.



- Dissolution rate depends on Rayleigh number, $Ra = k\Delta\rho g H/\mu D$. For a 200 m thick aquifer:
  - 3400 md, Ra ~ 59000, t_{on} = 0.08 yr, t_{slow} = 100 yr, t_{sat} = 1500 yr
  - 100 md, Ra ~ 2000, t_{on} = 200 yr, t_{slow} = 1000 yr, t_{sat} = 15000 yr

Unstable convection matters only in high perm aquifers. Dissolution reduces saturation of the CO_2 phase. Capillary snap-off will immobilize CO_2 as dissolution proceeds.

Adsorption/Desorption/Transport in Fractured Coal



adsorption on internal coal surfaces

increasing size

diffusion through the matrix and micropores

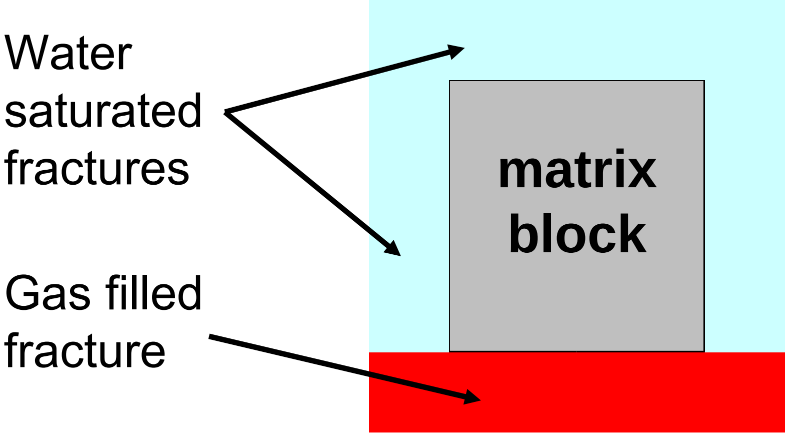
increasing size

bulk flow in the fracture network

In many coal beds, CH_4 is adsorbed on coal surfaces. When CO_2 is injected, it replaces the CH_4, which can then be recovered.

Key issues for modeling: time scale for adsorption equilibrium, changes in permeability as CO_2, CH_4 adsorb and desorb.

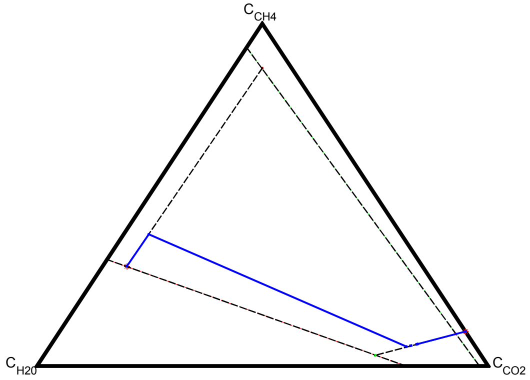
Equilibrium Adsorption in Coal Beds

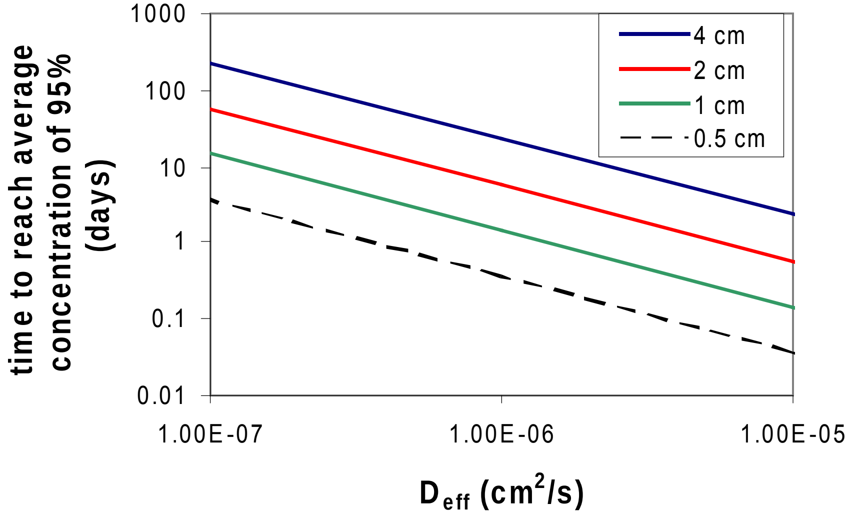


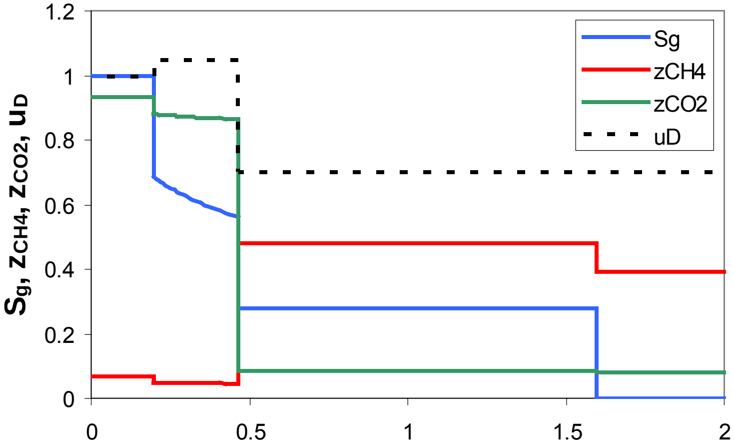
Water saturated fractures

Gas filled fracture

matrix block







If fractures are closely spaced, the equilibrium assumption is reasonable. Analytical solutions for 1D flow are then possible, as are streamline computations.

Conclusions

- Streamline methods offer speed and accuracy for the injection period – for high resolution compositional simulation (oil and gas) they are the only feasible choice.
- Other methods, tuned to physically-determined spatial and time scales, are needed for subsequent periods.
- Gravity relaxation in aquifers will cause capillary trapping, which occurs more rapidly than dissolution.
- Unstable convection, once underway, is always faster than diffusion for dissolving CO_2 in brine – it causes additional capillary trapping.
- High permeability is better than low, for injection rate, and for dissolution.
- Coal beds offer plenty of remaining challenges for modeling that honors the most important physical mechanisms.

Flow Prediction Posters
(These are the real authors of this talk!)

Please see the following posters for the full story (and the assumptions and caveats) behind these statements:

- Effect of Natural Convection on the Dissolution Trapping of CO_2 in Saline Aquifers (Marc Hesse, Amir Riaz, Hamdi Tchelepi).
- Three-dimensional Streamline Simulation of CO_2 Injection in Aquifers (Kristian Jessen)
- Analytical Modeling of CO_2 Storage and Enhanced Coal Bed Methane Recovery (Carolyn Seto and Kristian Jessen)
- Displacement Efficiency of Brine by CO_2 (Taku Ide and Kristian Jessen)
- Movement of the CO_2 Plume in Aquifers without Structural Closure (Marc Hesse)