Multi-scale multi-phase flow upscaling

Philip Ringrose
Statoil ASA & NTNU, Norway

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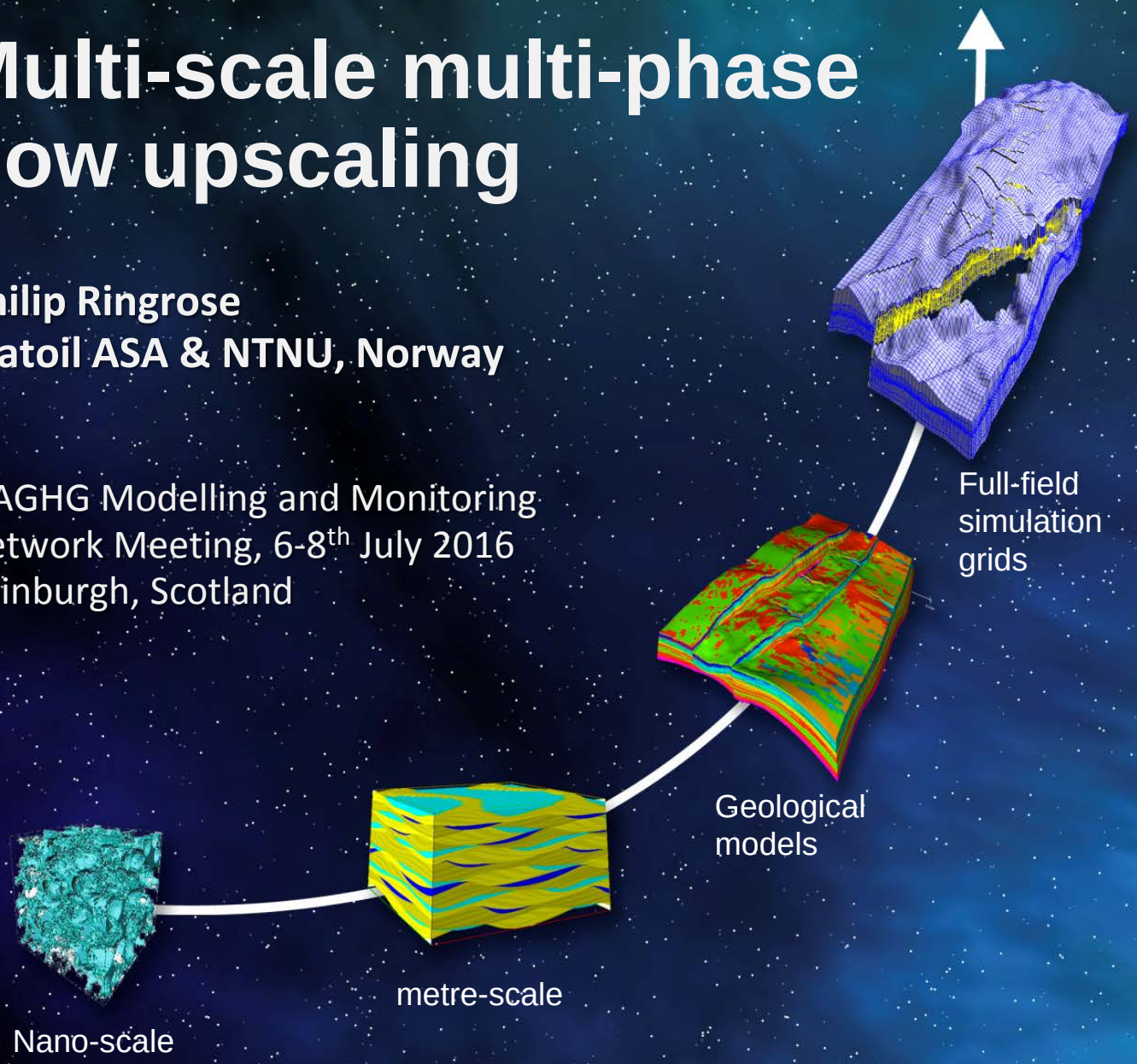

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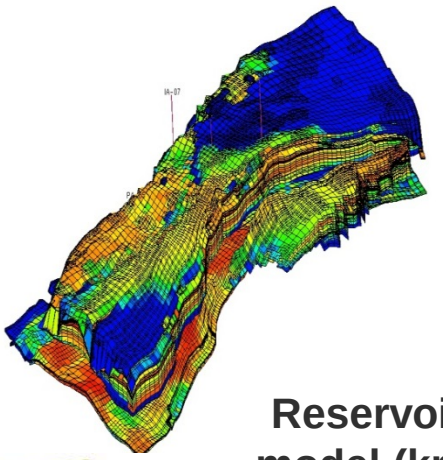
Handling a highly complex problem

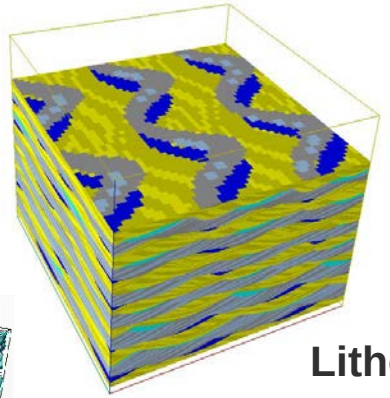
Goal: Build consistent multi-scale and multi-phase reservoir flow simulation models

To do this we need:

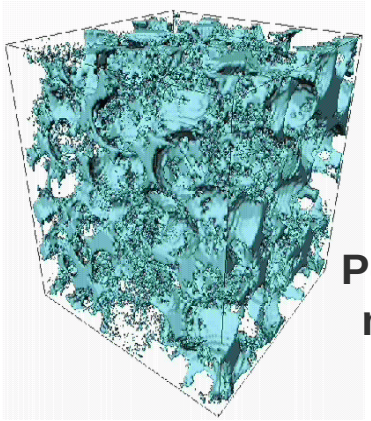
- Consistent comparison of measurements at different scales
- Rock-specific functions for the flow processes
- A geo-statistical framework (representative models)



Reservoir model (km)



Lithofacies model (m)



Pore network model (mm)

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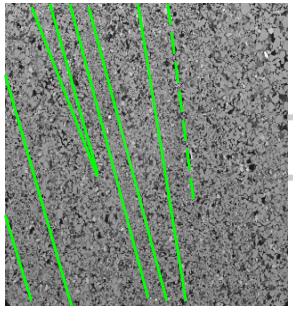
Pore to Field Workflow: Statfjord

Rustad et al., 2008 (SPE 113005)

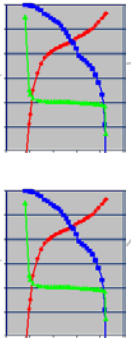
1. Identify lamina and pore types from core



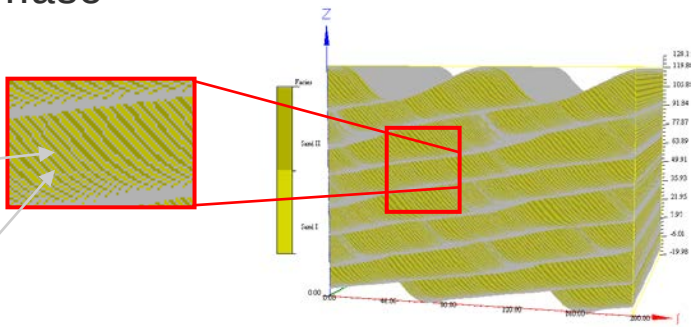
2. Calculate multiphase flow functions

Rock type 2

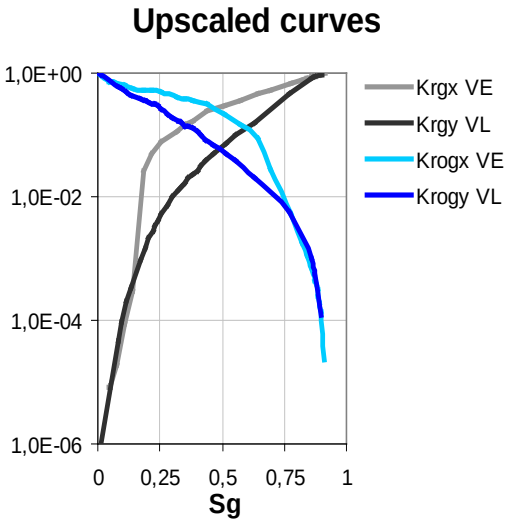
Rock type 1



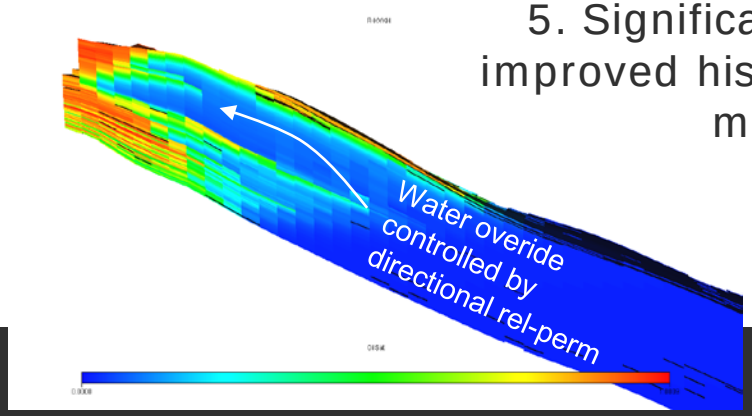
3. Apply functions in lithofacies models



4. Upscale lithofacies models



5. Significantly improved history match



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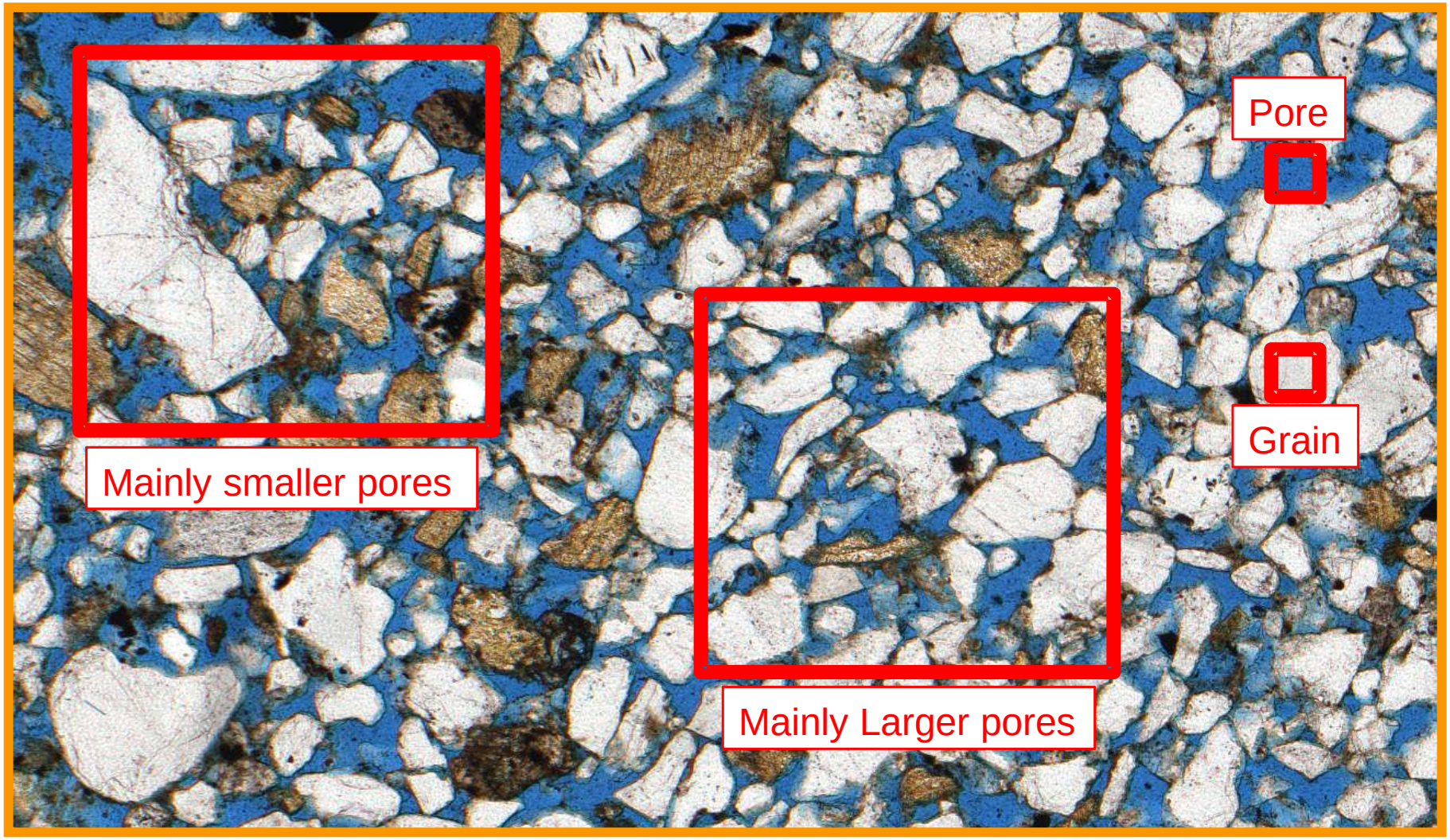
The Representative Elementary Volume (REV)

(after Bear 1972)



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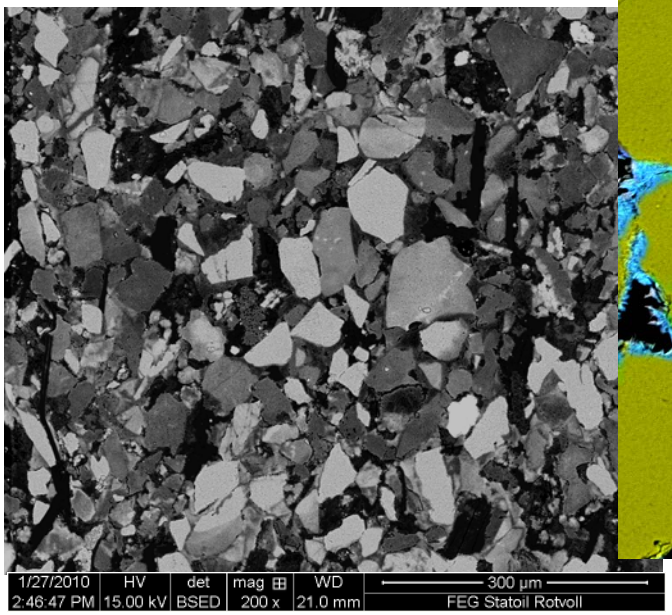
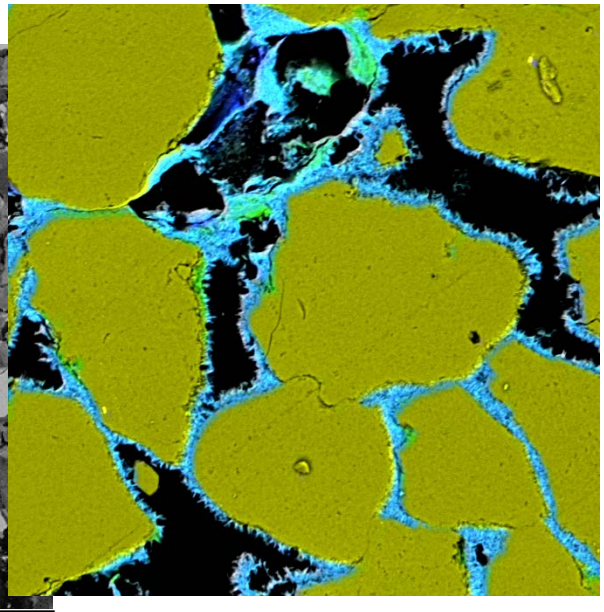
Pore-space characterisation

- Example core analysis, thin section, backscatter SEM mineralogical studies and pore-scale modelling used to estimate multiphase flow properties
- In Salah CCS project (Lopez et al. 2011, Ringrose et al., 2011)

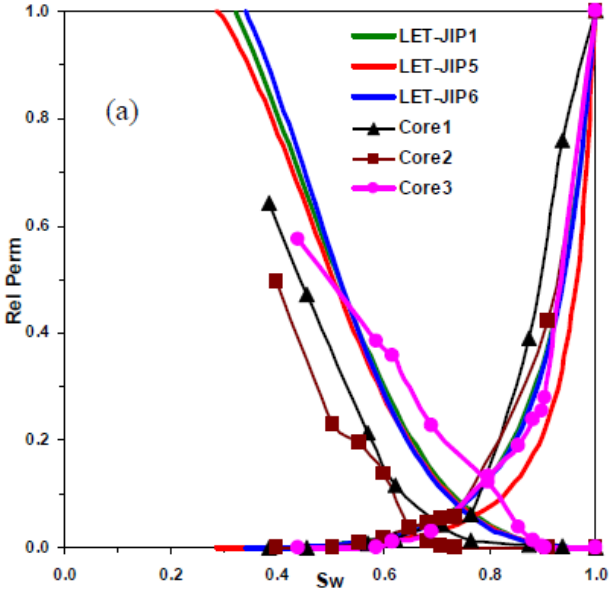
Grain characterisation
(cathodoluminescence)



Mineral identification
(BSEM)

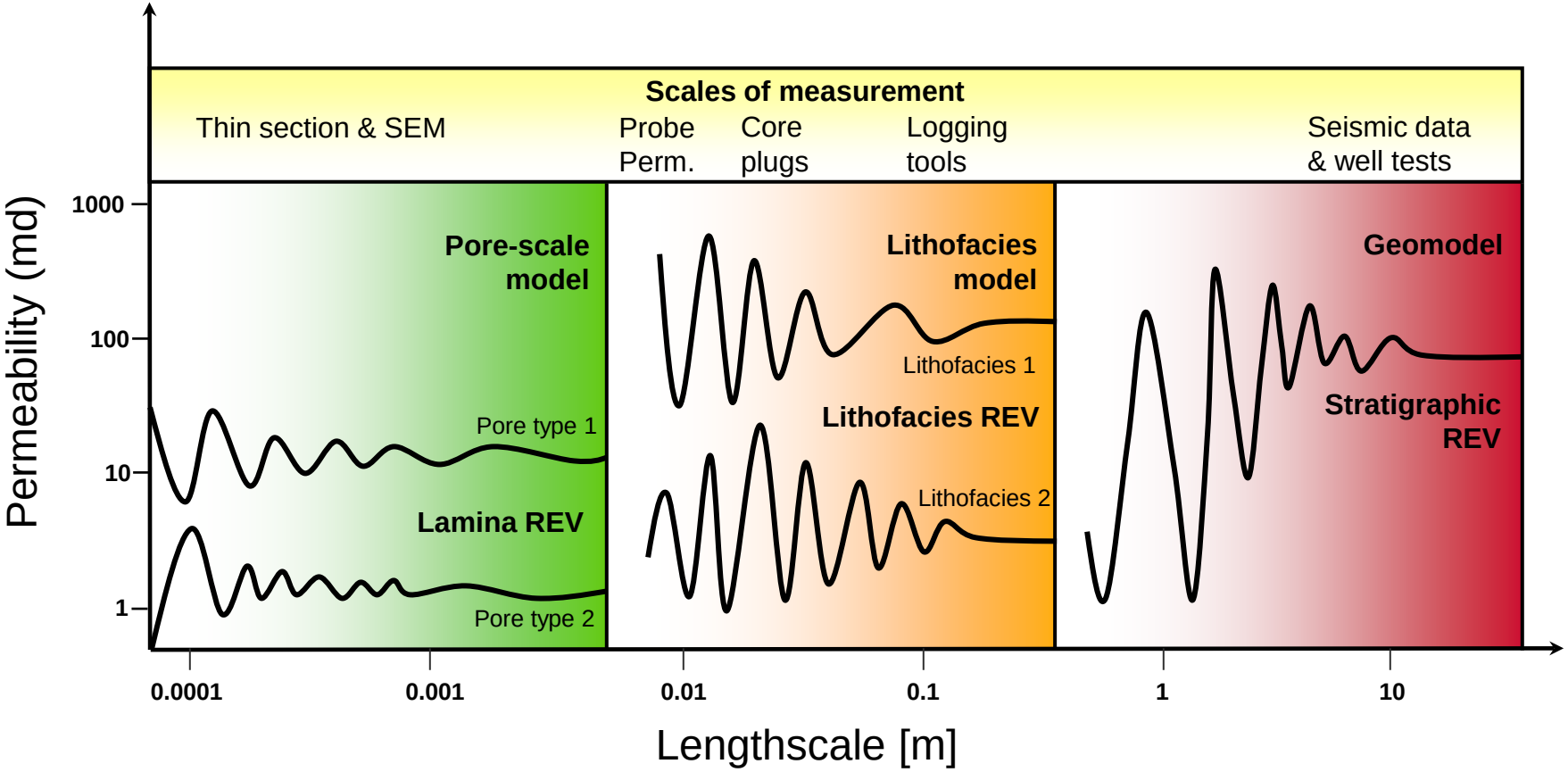


Pore Network Modelling



The REV concept as a framework for upscaling

The Representative Elementary Volume concept gives the framework for understanding geological and measurement scales

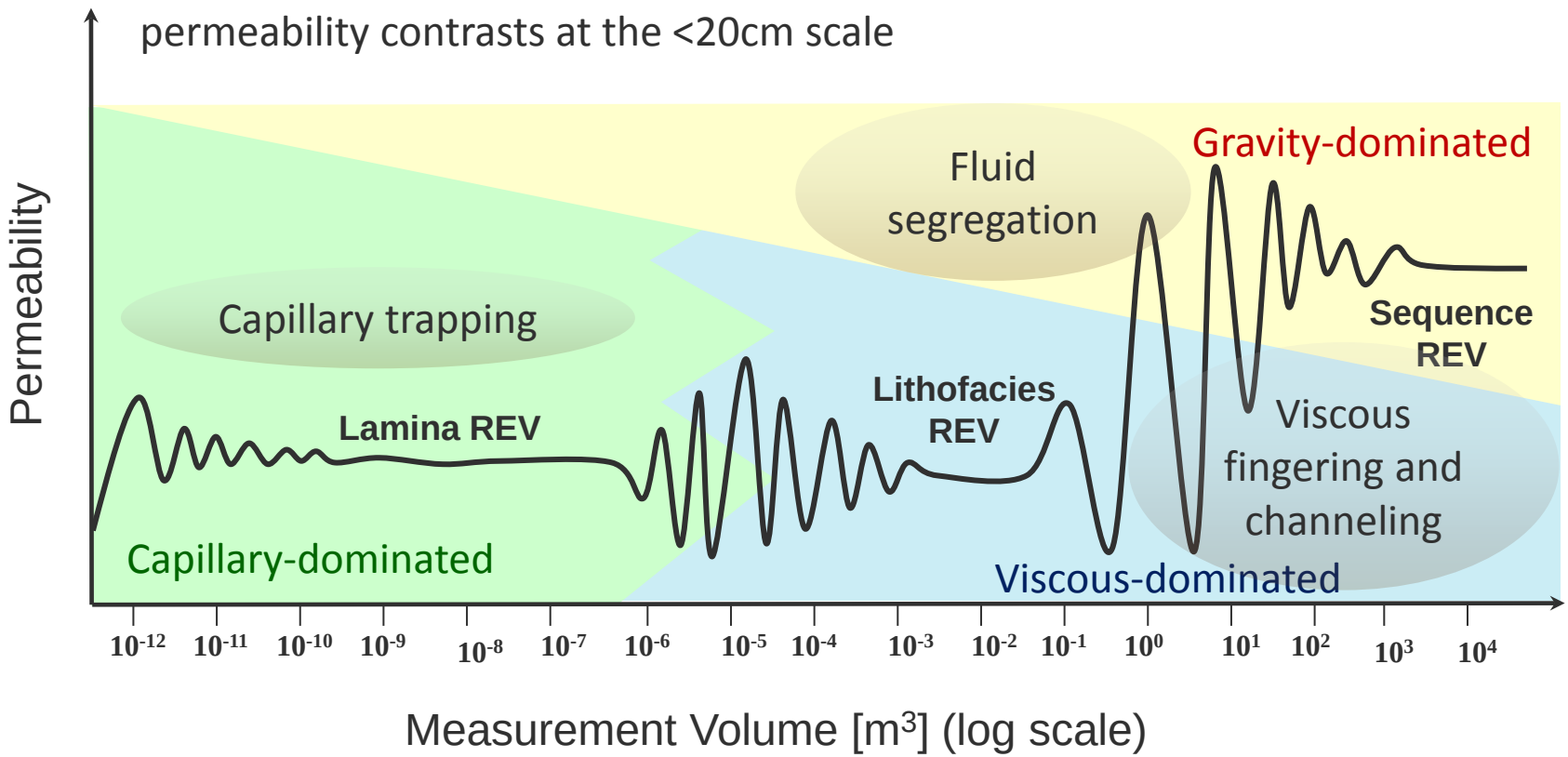


From Nordahl & Ringrose (2008) and Ringrose & Bentley (2015)

Multi-scale REV and fluid forces

The Balance of Forces concept merged with the REV concept is useful to indicate which scales most affect flow

e.g. capillary trapping is likely to be important for rocks with strong permeability contrasts at the <20cm scale



Fluid forces and scaling group theory

- The controls on two-phase immiscible flow can be captured in a set of dimensionless ratios or scaling groups (Ringrose et al., 1993; Li and Lake, 1995)

$$\frac{Viscous}{Capillary} = \frac{u_x \, \Delta x \, \mu_{CO_2}}{k_x (dP_c / dS)}$$

Darcy's Law

Length scale (grid size)

Capillary Pressure gradient

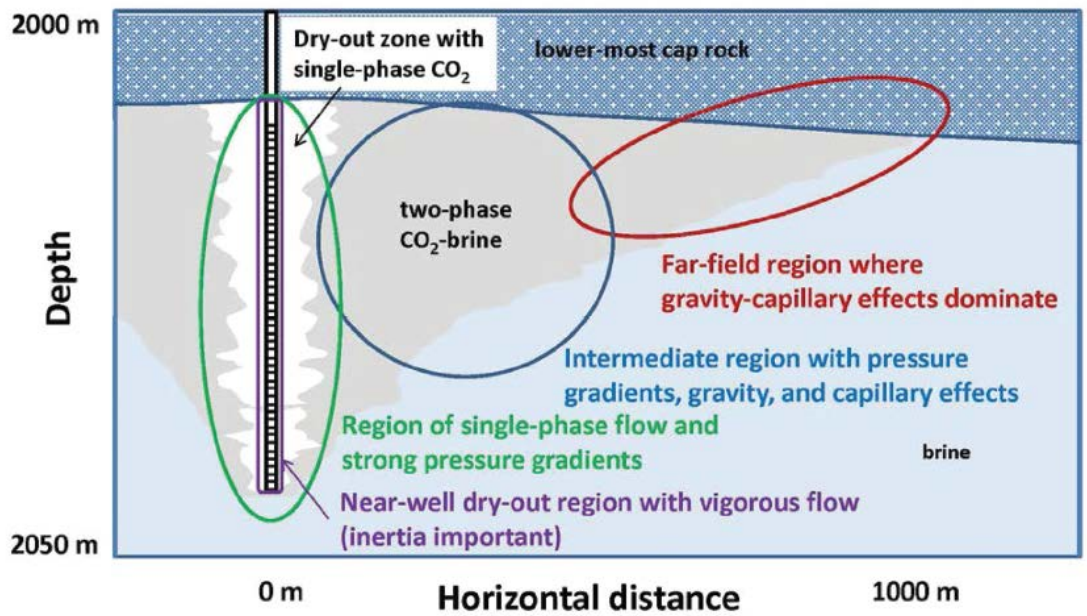
$$\frac{Gravity}{Capillary} = \frac{\Delta\rho \, g \, \Delta z}{(dP_c / dS)}$$

$$\frac{Viscous}{Gravity} = \frac{q \, \Delta x \, \mu_{CO_2}}{\Delta\rho \, g \, \Delta z}$$

Where Δx, Δz are total system dimensions, Dr is the fluid density difference, μ_{CO2} is the viscosity of CO_2 and dP_c/dS is the capillary pressure gradient wrt saturation

Which forces control CO_2 storage?

Fluid process and domains for a hypothetical GCS reservoir (Oldenburg et al. 2016)

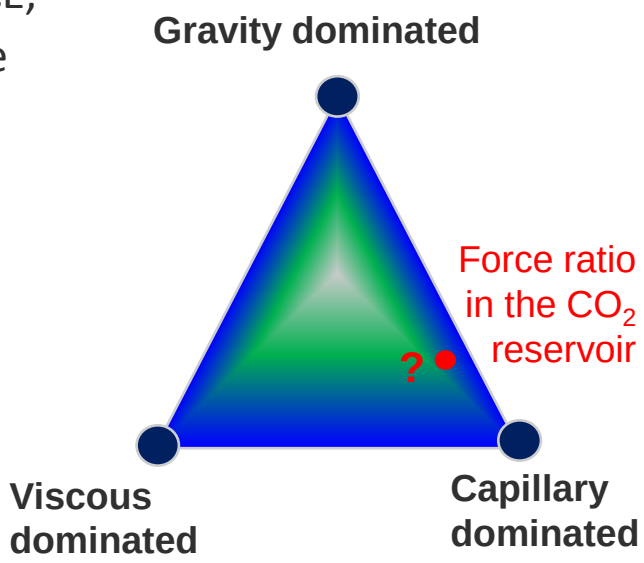


Two-phase Steady-State Solutions

Numerous recipes for solving multi-phase flow problems (incl. dynamic, non-steady state)

Steady-state solutions for immiscible two-phase flow are the end-member cases:

- ***Viscous limit* (VL):** The assumption that the flow is steady state at a constant fractional flow. Capillary pressure assumed to be negligible.
- ***Capillary equilibrium* (CE):** The assumption that saturations are controlled by the capillary pressure curves. Applied pressure gradients assumed to be negligible.
- ***Gravity-Capillary equilibrium* (GCE):** Similar to CE, except that the saturations are controlled by the effects of gravity:
  - **Vertical equilibrium** (VE): a simplified gravity equilibrium assumption but with capillary forces neglected

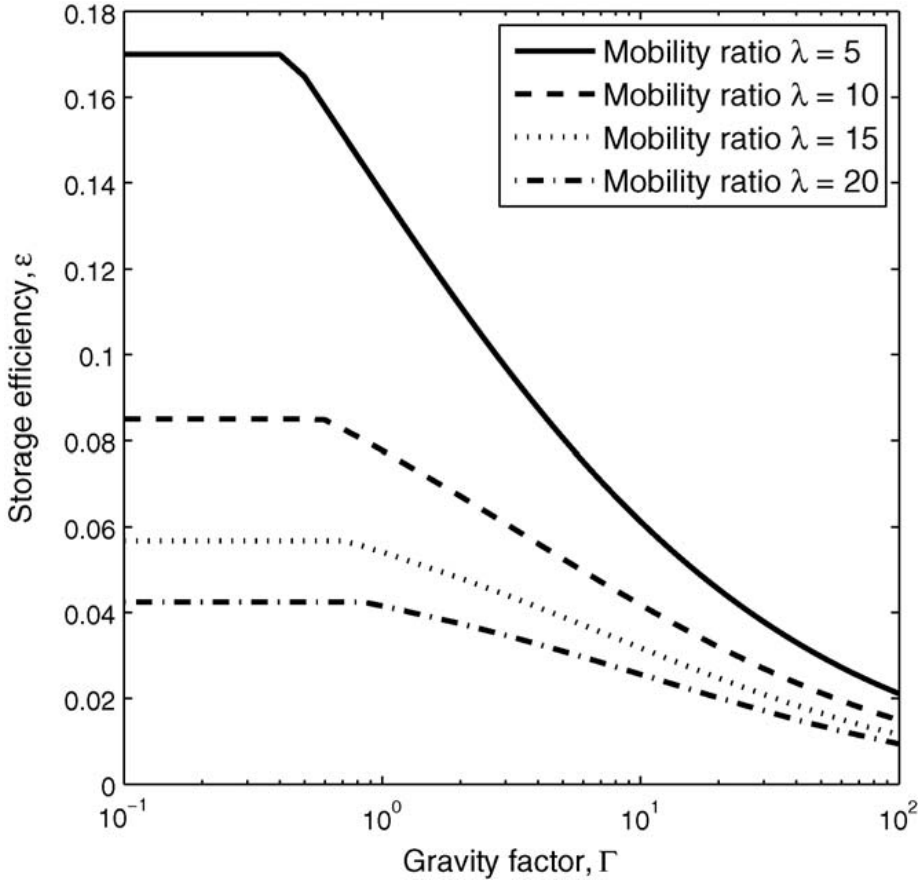


Analytical solutions for a buoyant plume

- Nordbotten et al. (2005) and Nordbotten & Celia (2006) proposed a dimensionless group, Γ , to characterise an ideal solution for CO_2 injection into a confined aquifer (a version of the viscous-gravity ratio):

$$\Gamma = \frac{2\pi \Delta\rho k \lambda_b B^2}{Q_{well}}$$

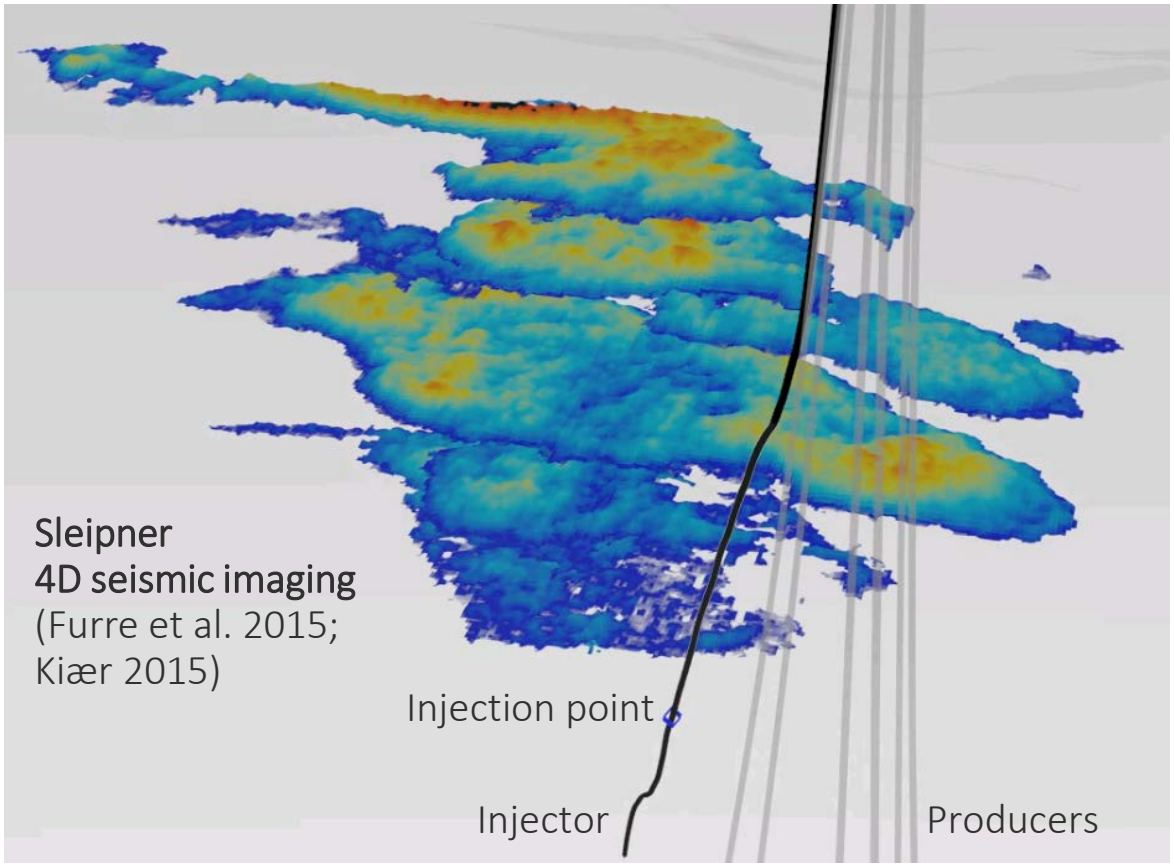
- Okwen et al. (2010) derived the storage efficiency factors, ε, as a function of Γ for various mobility ratios (residual brine saturation, S_r = 0.15)
- For higher gravity numbers Γ>10 there is a significant loss in storage efficiency

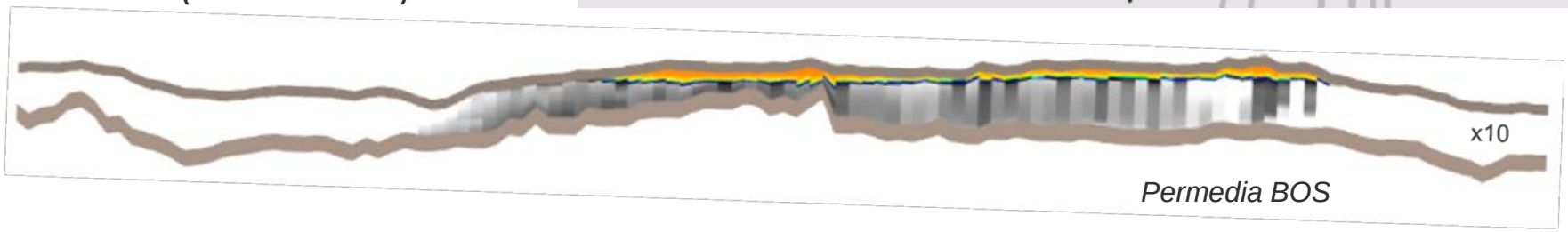


Storage efficiency ε vs. gravity factor Γ (from Okwen et al. 2010)

Insights from Sleipner

- Important insights into CO_2 flow dynamics from the seismic time-lapse data
  - ➢ Gravity segregation and top-structure control of plume shape
  - ➢ Multi-layer system with thin-bed effects on seismic
  - ➢ Insights on dissolution rate
- High-resolution simulation from Cavanagh (2013):
  - ➢ Sleipner Layer-9 reference model (time = 2008)





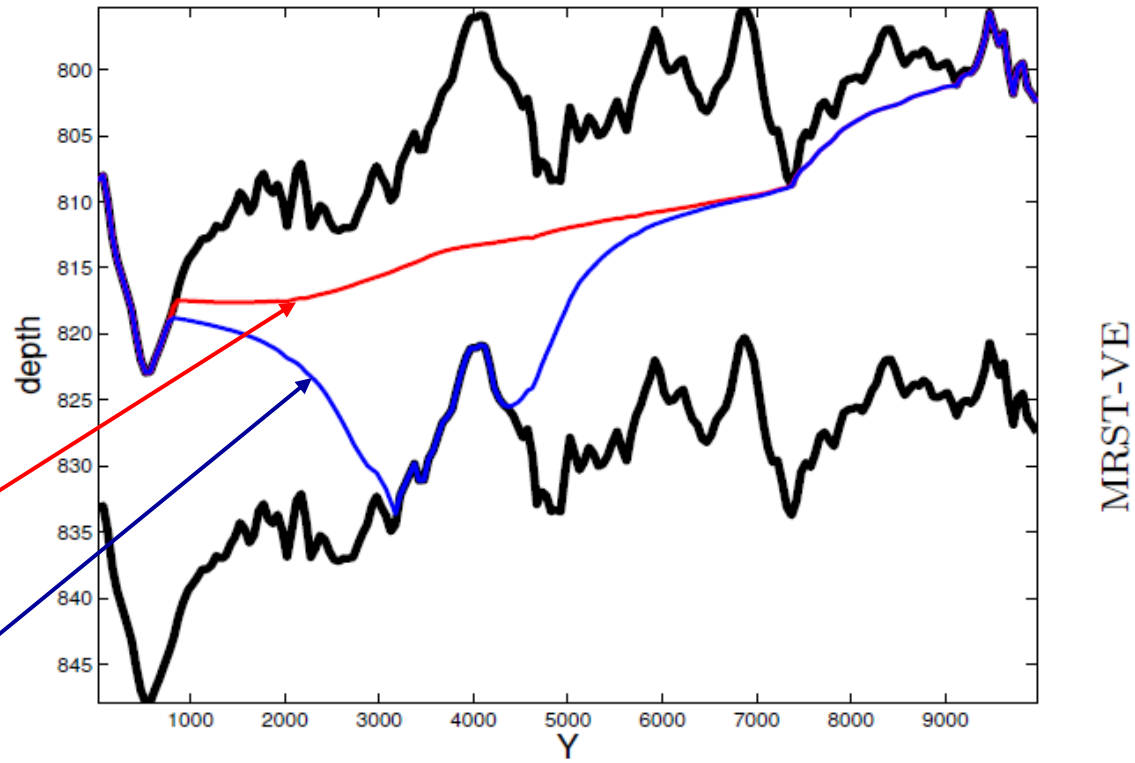
VE applied to Sleipner

- Nilsen et al. (2011) tested various VE models to look at vertical segregation of CO_2 and brine for the Sleipner (Layer 9) reference model
- They showed that vertical segregation occurs in a relatively short time and that the system reaches vertical equilibrium before the end of the injection period

Example VE simulation result from Nilsen et al. (2011):
- Layer 9 cross-section after 32 years injection

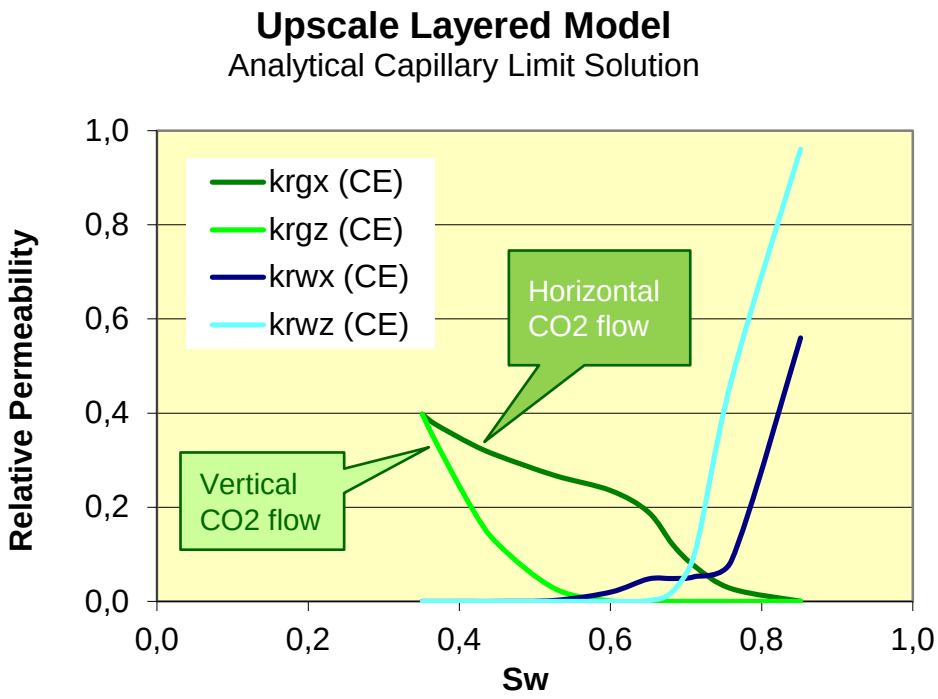
Mobile CO_2 (structural tapping)

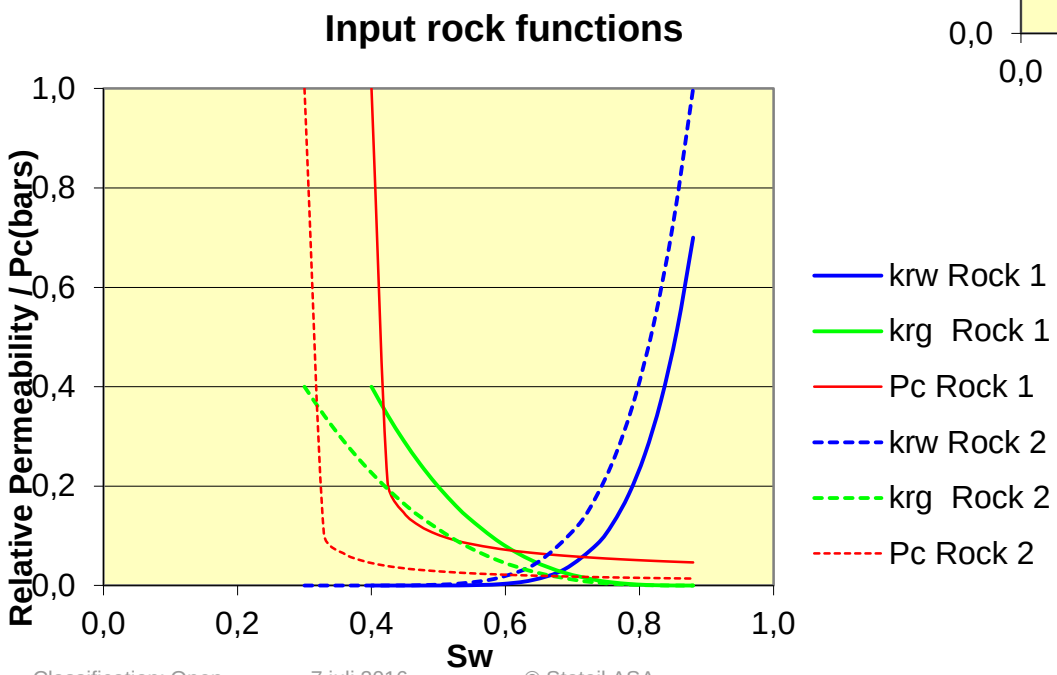
CO_2 trapped as residual saturation

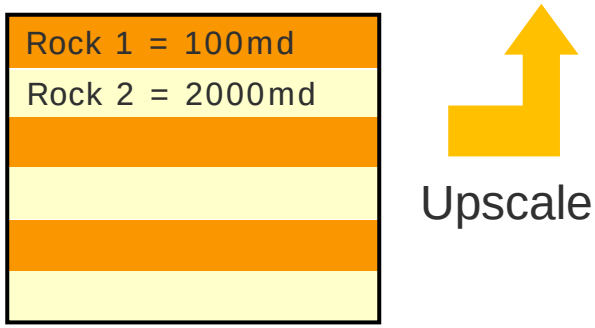


CE applied to Snøhvit

- Analytical CE upscaling for a layered medium with CO_2-brine functions
- Based on Snøhvit Tubåen data: lithofacies-scale, fluvio-deltaic system, assumes 20:1 permeability contrast
- Note how anisotropy in CO_2 flux varies with saturation







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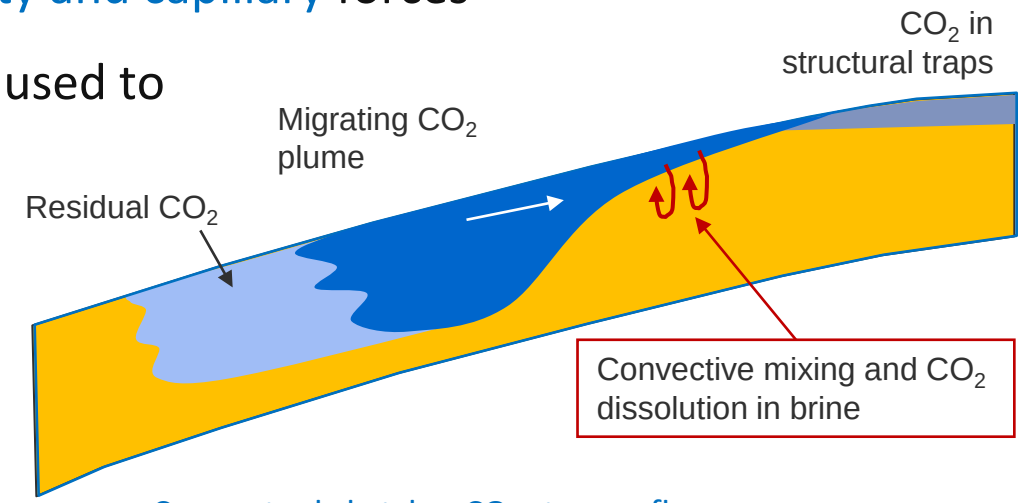
Summary: CO_2 storage flow upscaling

- Well-established routines for building multi-scale and multi-phase reservoir flow simulation models
- This highly complex problem should be handled using the multi-scale REV concept – geology has inherent characteristic lengthscales
- The CO_2-brine flow modeling problem requires careful assessment of the gravity, viscous and capillary force ratios
- CO_2 storage is dominated by gravity and capillary forces
- Multi-scale approaches should be used to improve forecasts and models of CO_2 storage processes



Conceptual sketch – CO_2 storage flow processes

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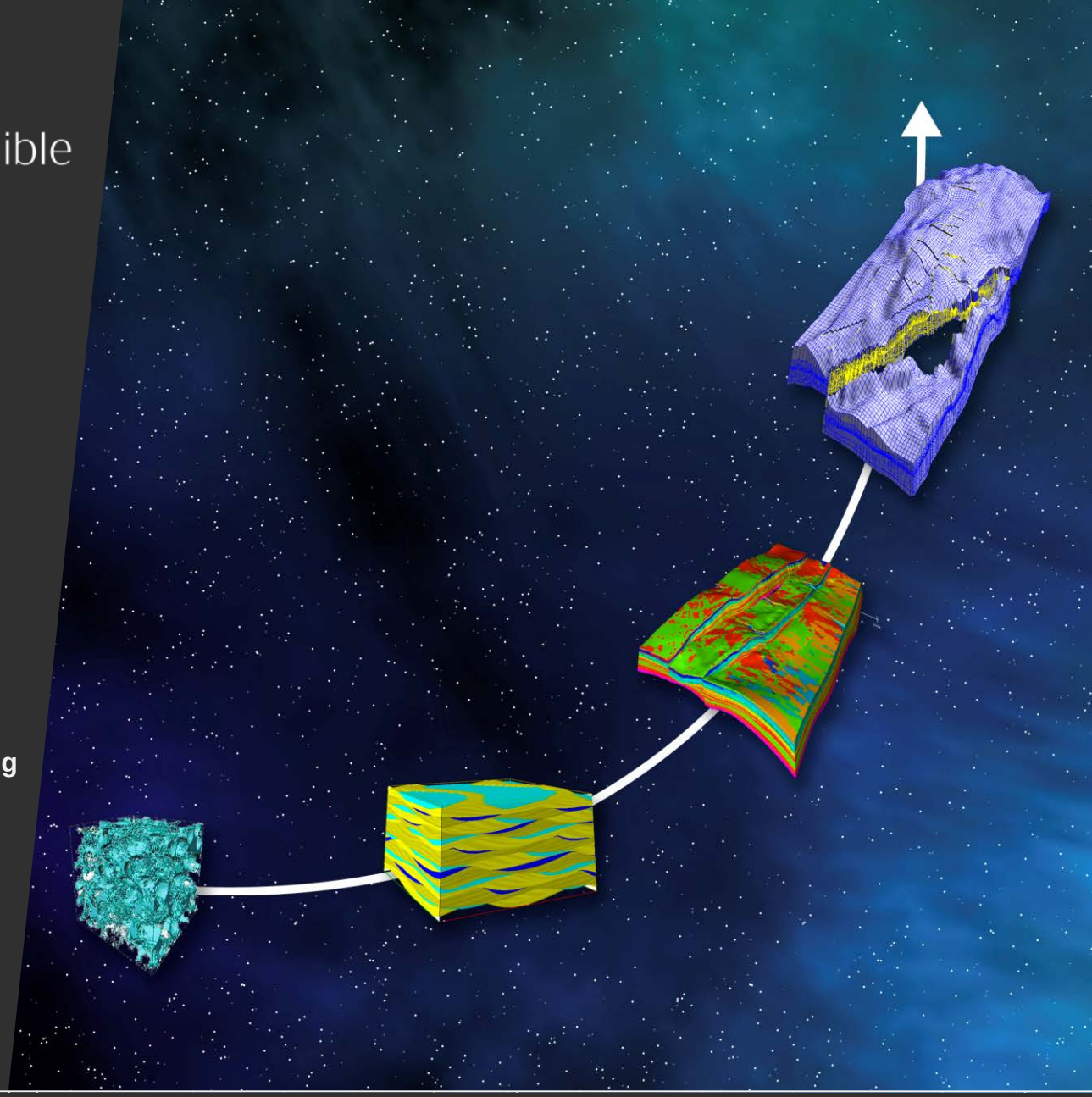

Multi-scale, multi-phase flow upscaling

Philip Ringrose

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