Durham University

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Estimating injectivity for saline aquifers – The UKSAP method

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November 2011

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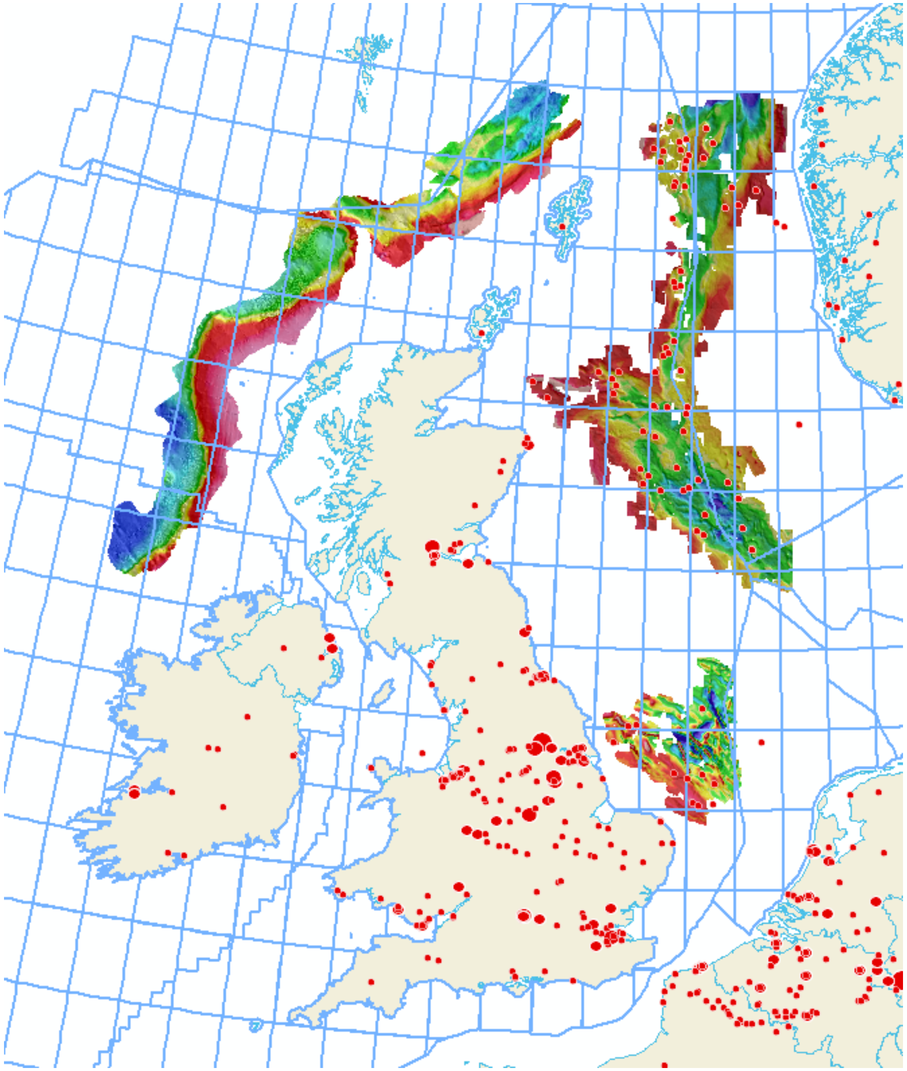
This work has been part funded through the UK Storage Appraisal Project, with investment from the Energy Technologies Institute.

WorleyParsons resources & energy
THE CROWN ESTATE
ERC equipoise
Knowledge Transfer Partnerships
energy technologies institute

Outline

- UKSAP injectivity method.
- Preliminary results and economic implications.
- Simplifying assumptions.
- Role of partial miscibility.
- Sensitivity to uncertainty concerning relative permeability data.
- Role of heterogeneity.
- Pressure data from Snohvit.

UK Storage Appraisal Project



Depth to top of reservoir [m]
Area of formation [km^2]
Av Gross Thickness [m]
Av Vertical NTG [frac]
Av Porosity [frac]
Storage Formation Permeability [mD]
Temperature [^{o}C]
Salinity [kg/l]
Porosity (%)
Rock compressibility [MPa^{-1}]
Residual water saturation [-]
CO_2 end-point relative permeability [-]
Formation fracture pressure [MPa]
Virgin formation pressure [MPa]

Number of wells matrix

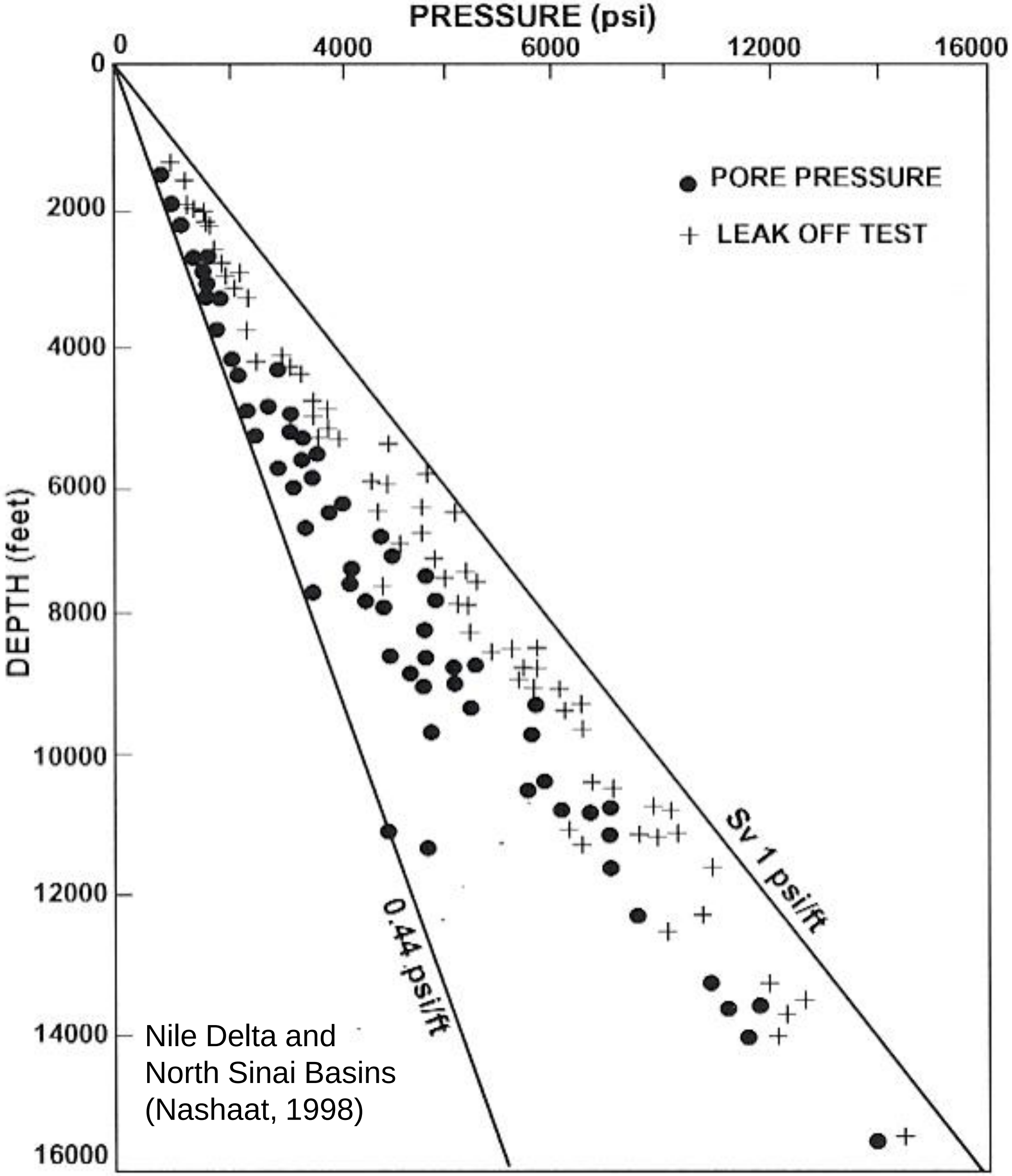
CO_2 Injection Rate [Mt/yr]	Injection Duration (yr)			
	10	20	30	40
2	1	1	1	1
5	1	2	2	2
10	3	3	14	
15	4	21		
20	6			
40				
60				

Pressure limited storage capacity

As CO_2 is injected, pressure increases.

It is necessary to avoid exceeding the fracture pressure of the cap-rock.

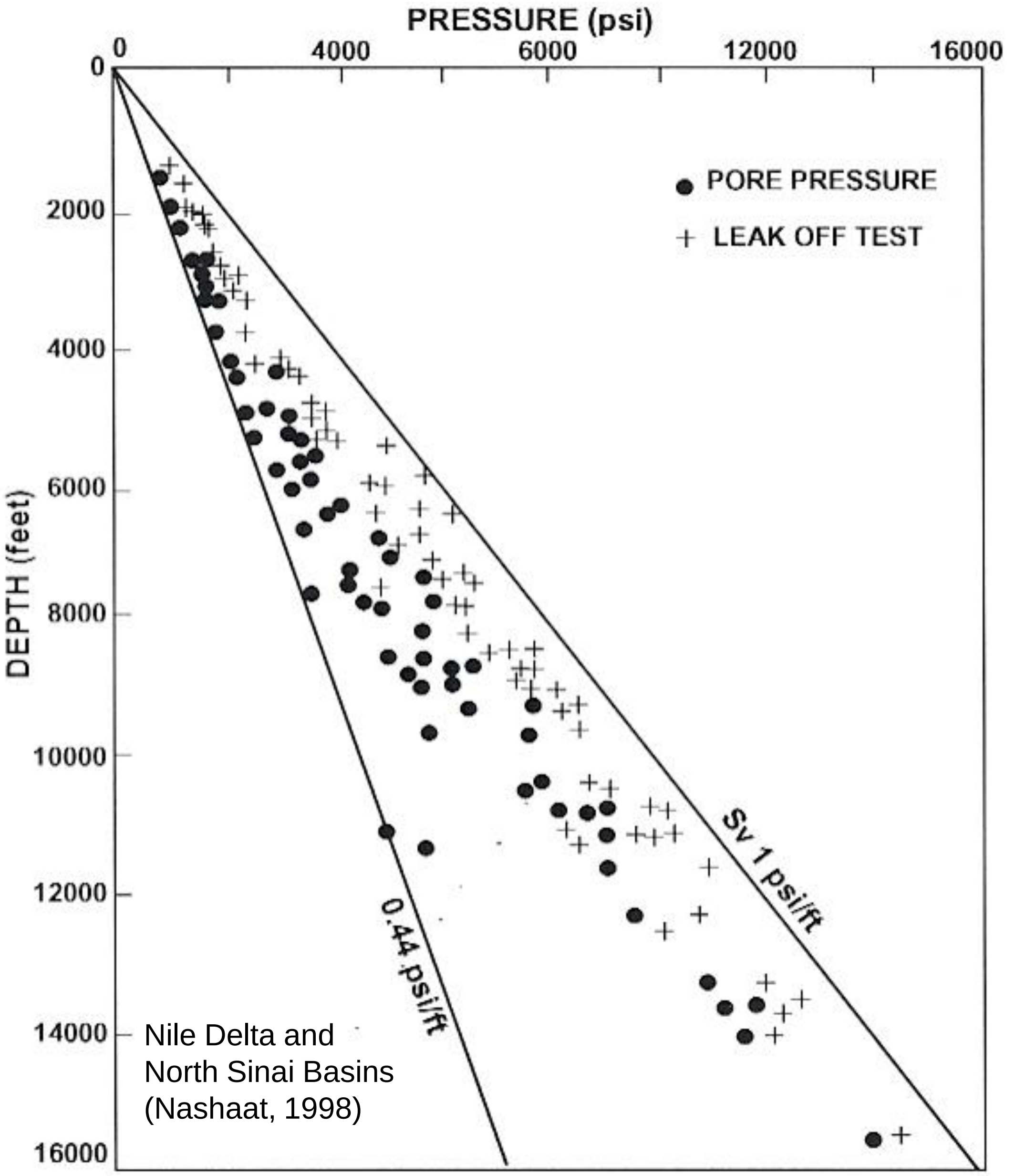
The amount of CO_2 that can be stored is often pressure limited.



UKSAP maximum allowable pressure

The minimum of:

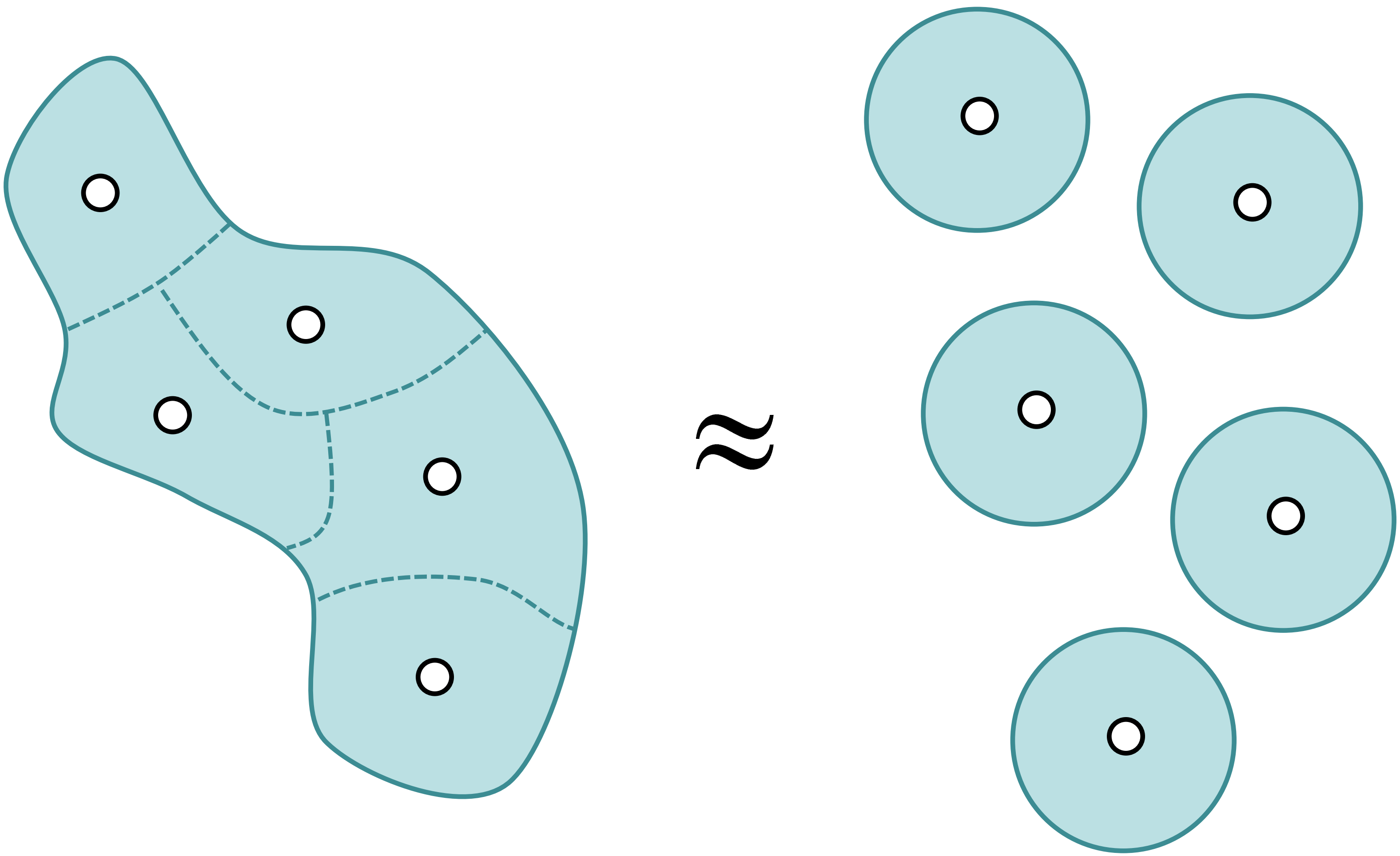
1. 90% of the fracture pressure;
2. 90% of the lithostatic pressure (the overburden);
3. 100% estimated maximum downhole pressure that can be sustained by a surface pressure of 25 MPa (surface pressure + gravity head – frictional loss).



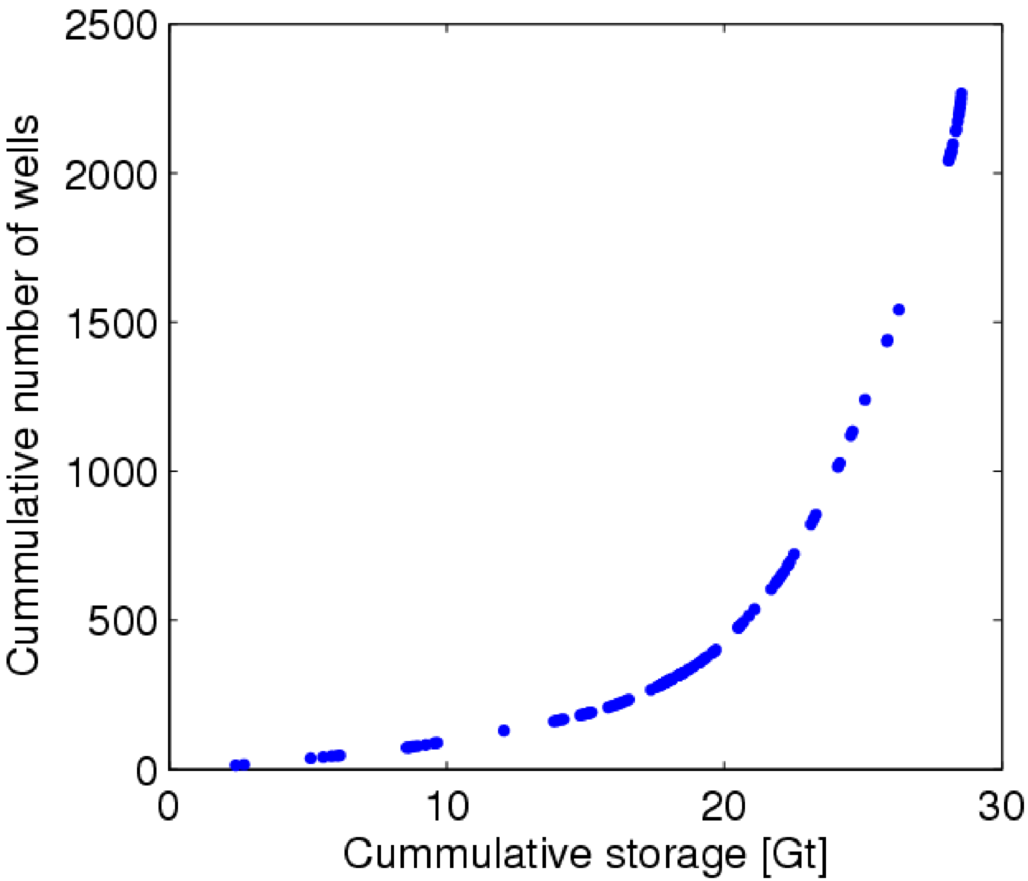
Workflow

1. Calculate maximum pressure buildup in the injection well due to constant injection of CO_2.
2. If the pressure buildup > maximum allowable pressure the domain is split up to accommodate an additional injection well.
3. Injection rate is then distributed between wells and maximum pressure buildup is reassessed.
4. Number of wells sequentially increased until estimated maximum pressure buildup < maximum allowable pressure.

Multiple well studies



Preliminary results from 200 closed saline aquifers

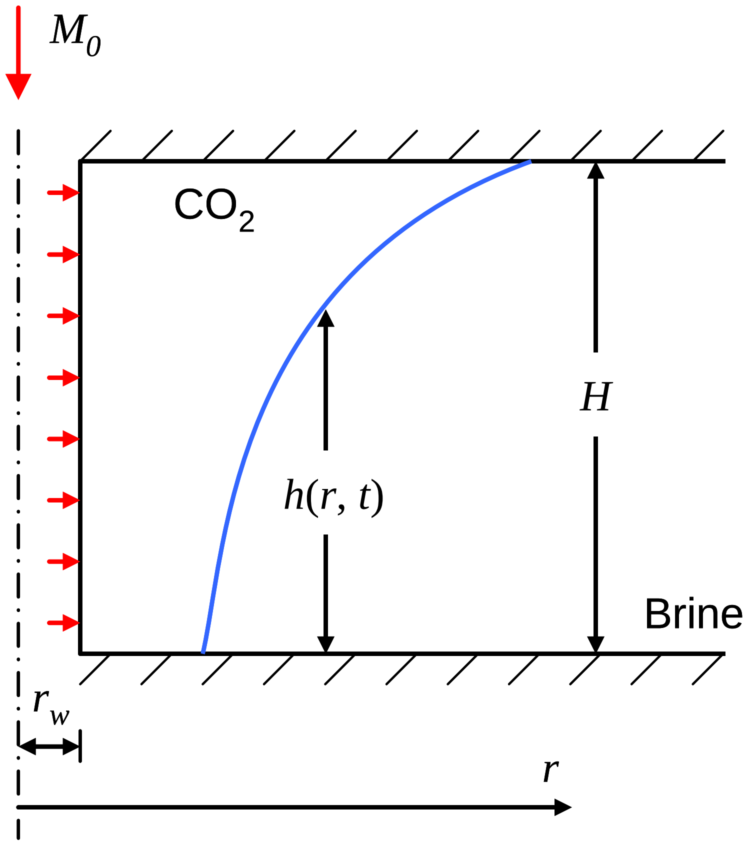


How do you want to report it?

1) At least 2500 wells needed to store less than 30 Gt of CO_2.
2) 1030 wells required to store total UK emissions for 40 years (~24 Gt).
3) Cost of drilling wells for storing 40 years of UK emissions £0.43 / t CO_2 (assuming 10 million £ per well).

Results are based on one deterministic realisation using maximum likelihood parameters.

Simplifying assumptions



1) Vertical pressure equilibrium.

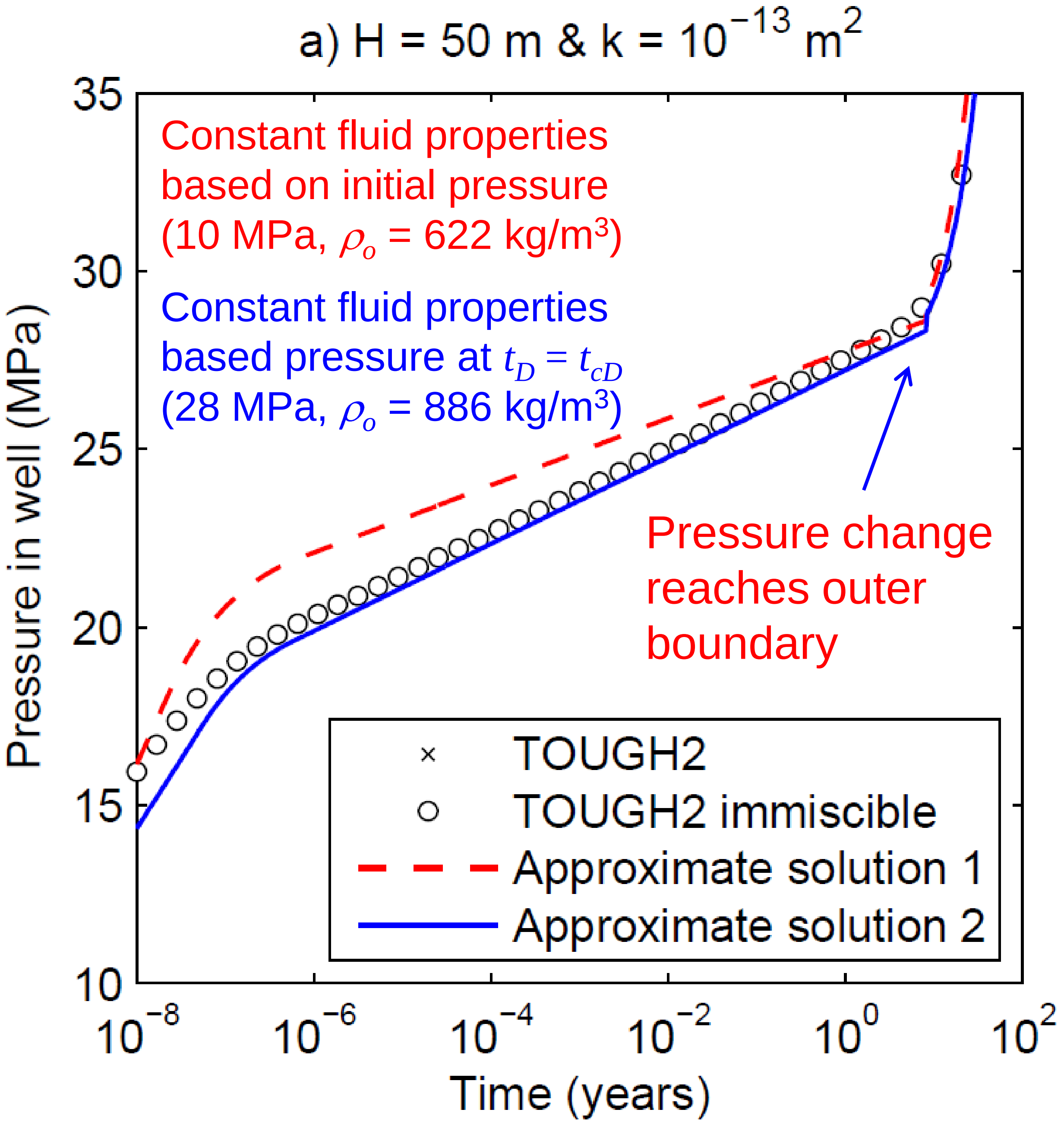
2) Negligible capillary pressure.

3) Constant fluid properties.

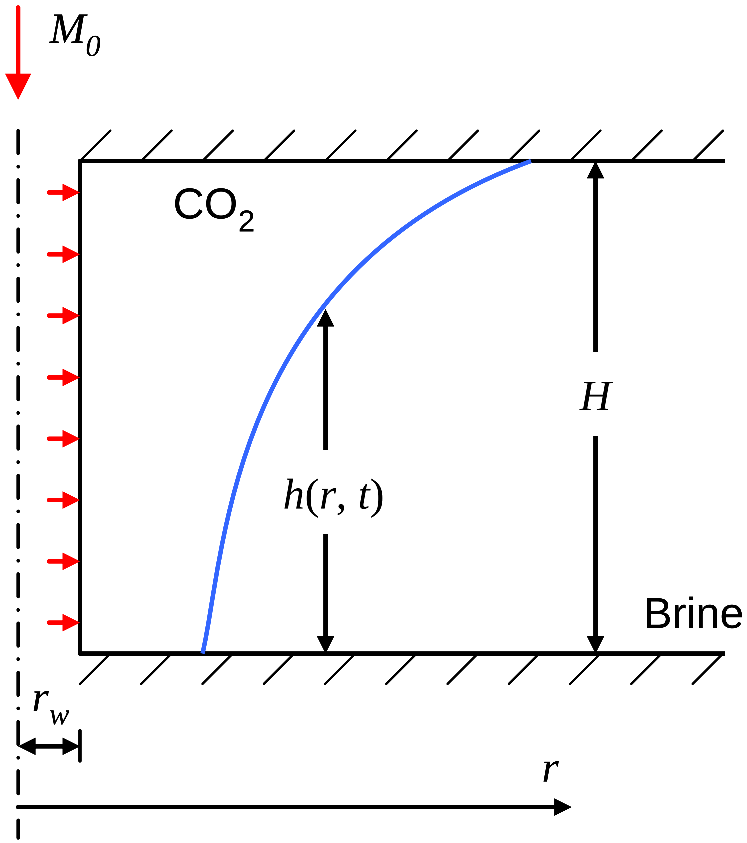
4) Immiscible flow (no brine evaporation and no CO_2 dissolution).

5) Linear relative permeability.

6) Homogenous and isotropic formation.


a) H = 50 m & k = 10^{-13} m^2
Constant fluid properties
based on initial pressure
(10 MPa, ρ_o = 622 kg/m^3)
Constant fluid properties
based pressure at $t_D = t_{cD}$
(28 MPa, ρ_o = 886 kg/m^3)
Pressure change
reaches outer
boundary
TOUGH2
TOUGH2 immiscible
Approximate solution 1
Approximate solution 2
Pressure in well (MPa)
Time (years)
35
30
25
20
15
10
10^{-8}
10^{-6}
10^{-4}
10^{-2}
10^{0}
10^{2}

Simplifying assumptions



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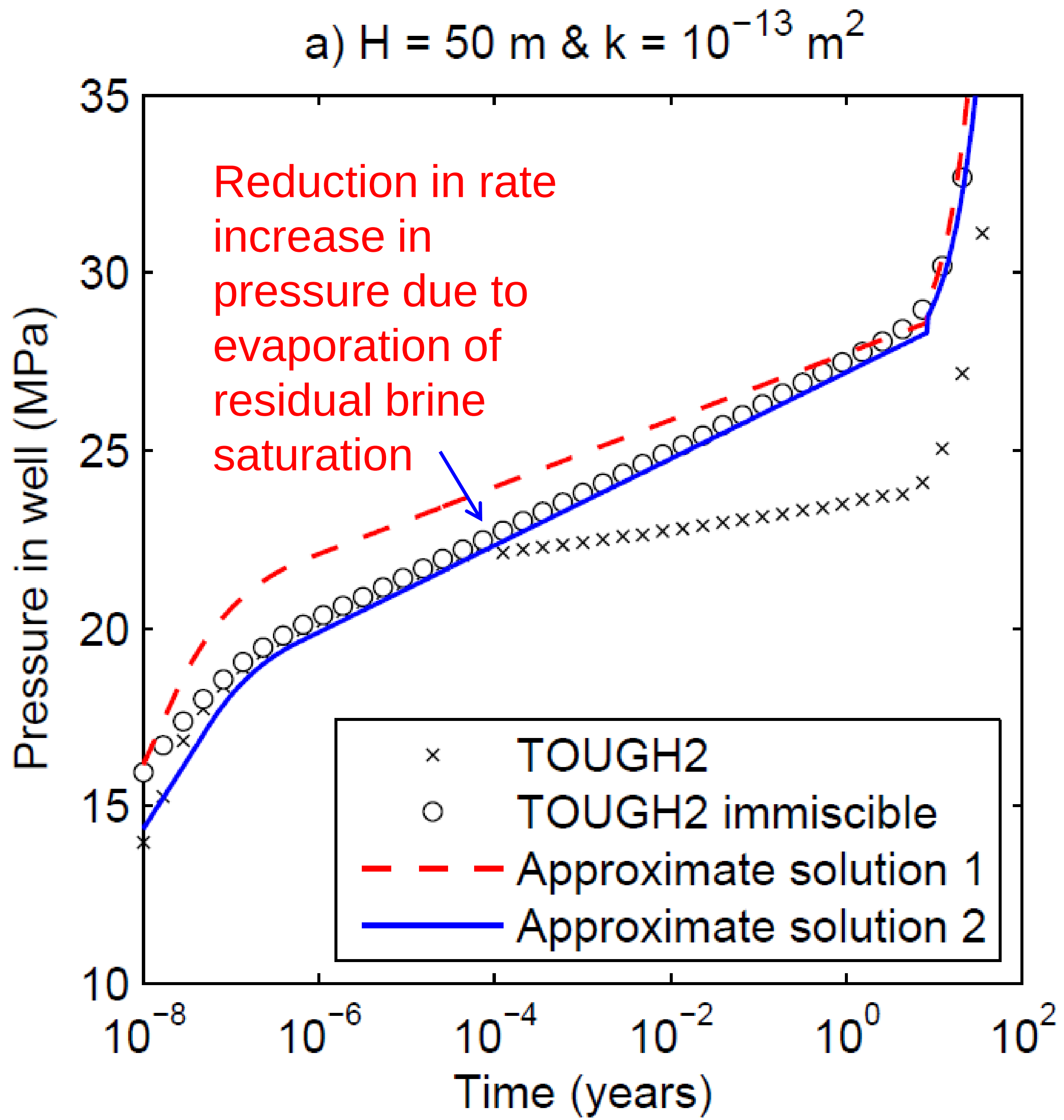
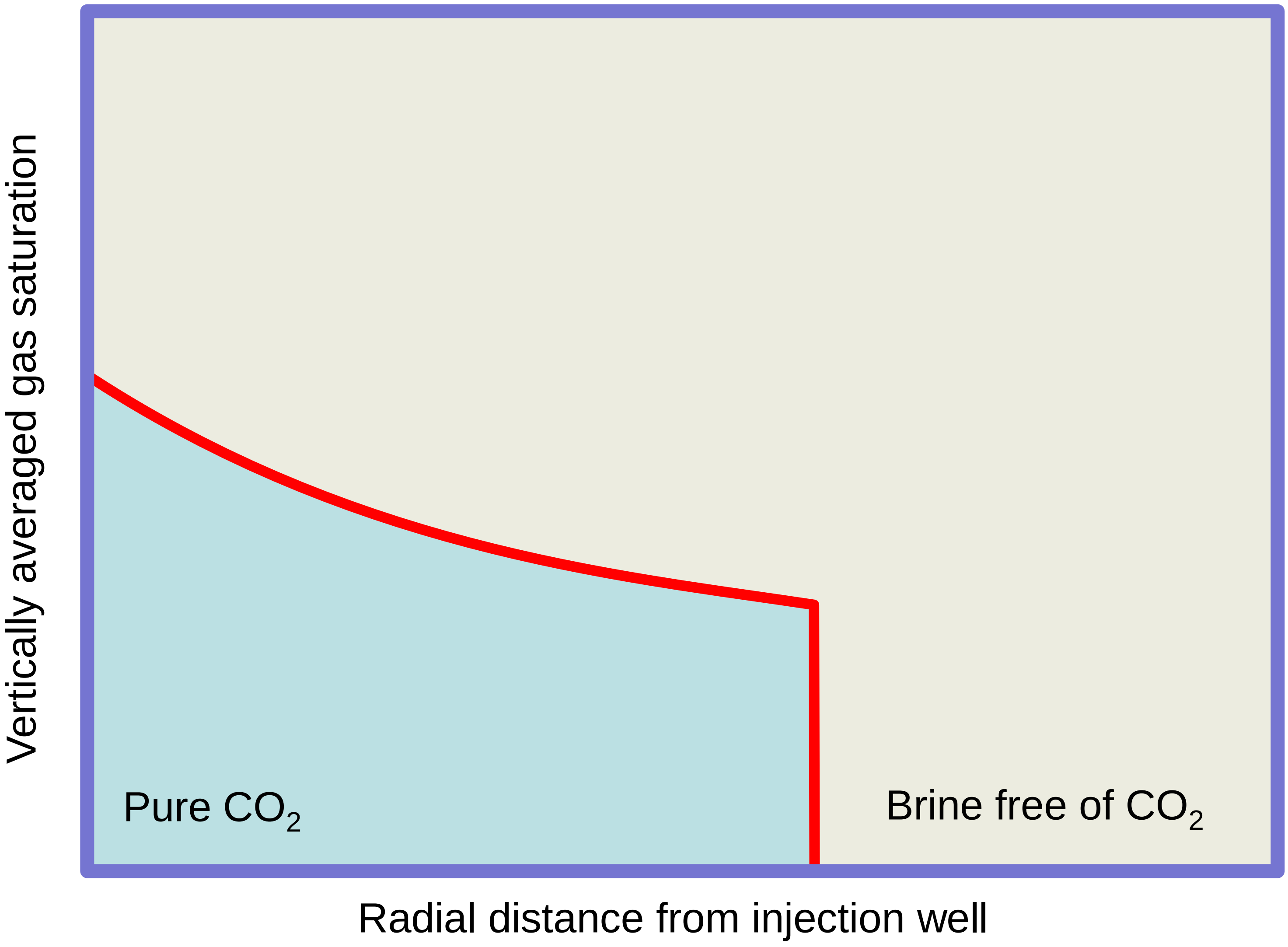
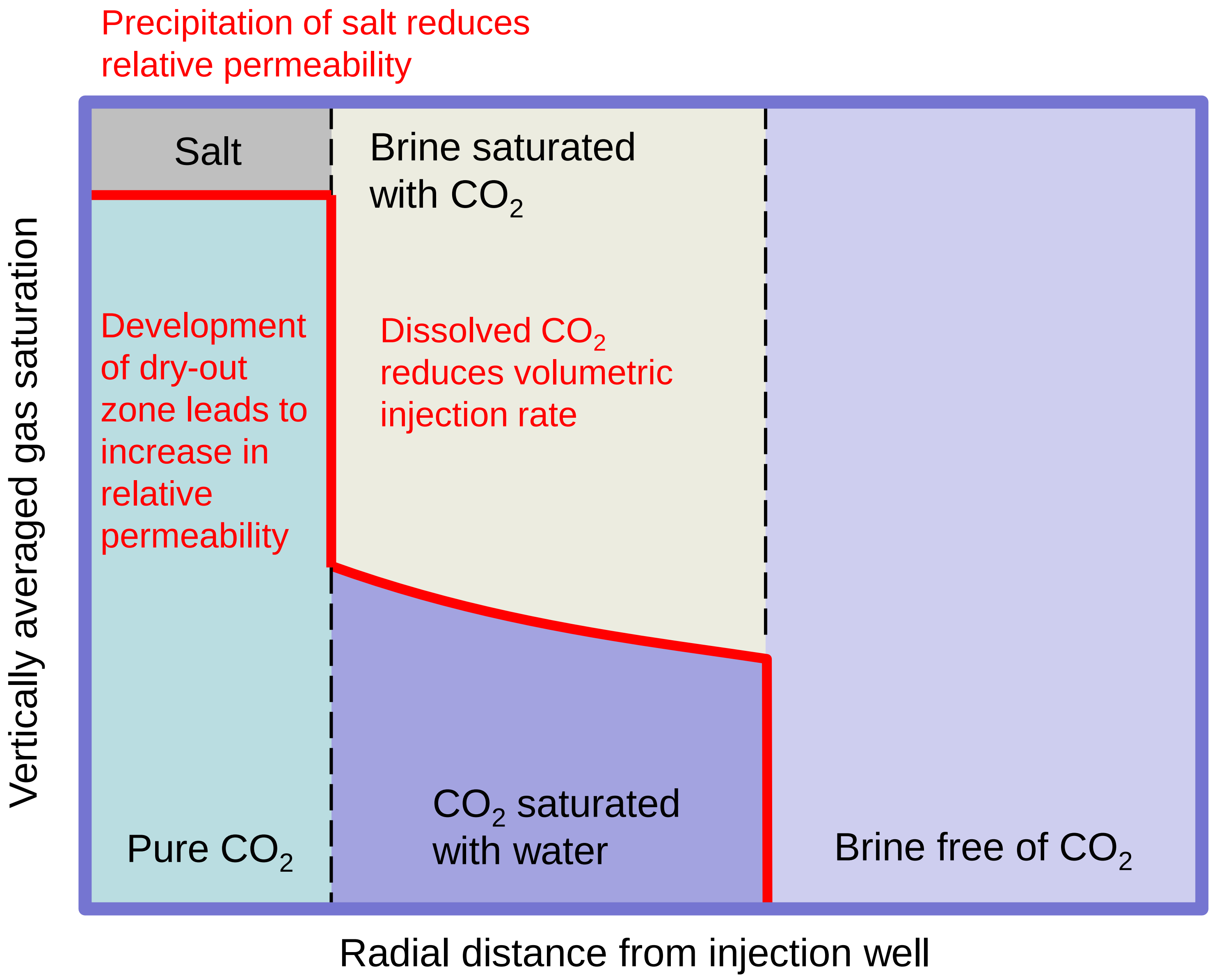

a) H = 50 m & k = 10^−13 m^2
Reduction in rate increase in pressure due to evaporation of residual brine saturation
Pressure in well (MPa)
35
30
25
20
15
10
10^−8
10^−6
10^−4
10^−2
10^0
10^2
Time (years)
TOUGH2
TOUGH2 immiscible
Approximate solution 1
Approximate solution 2

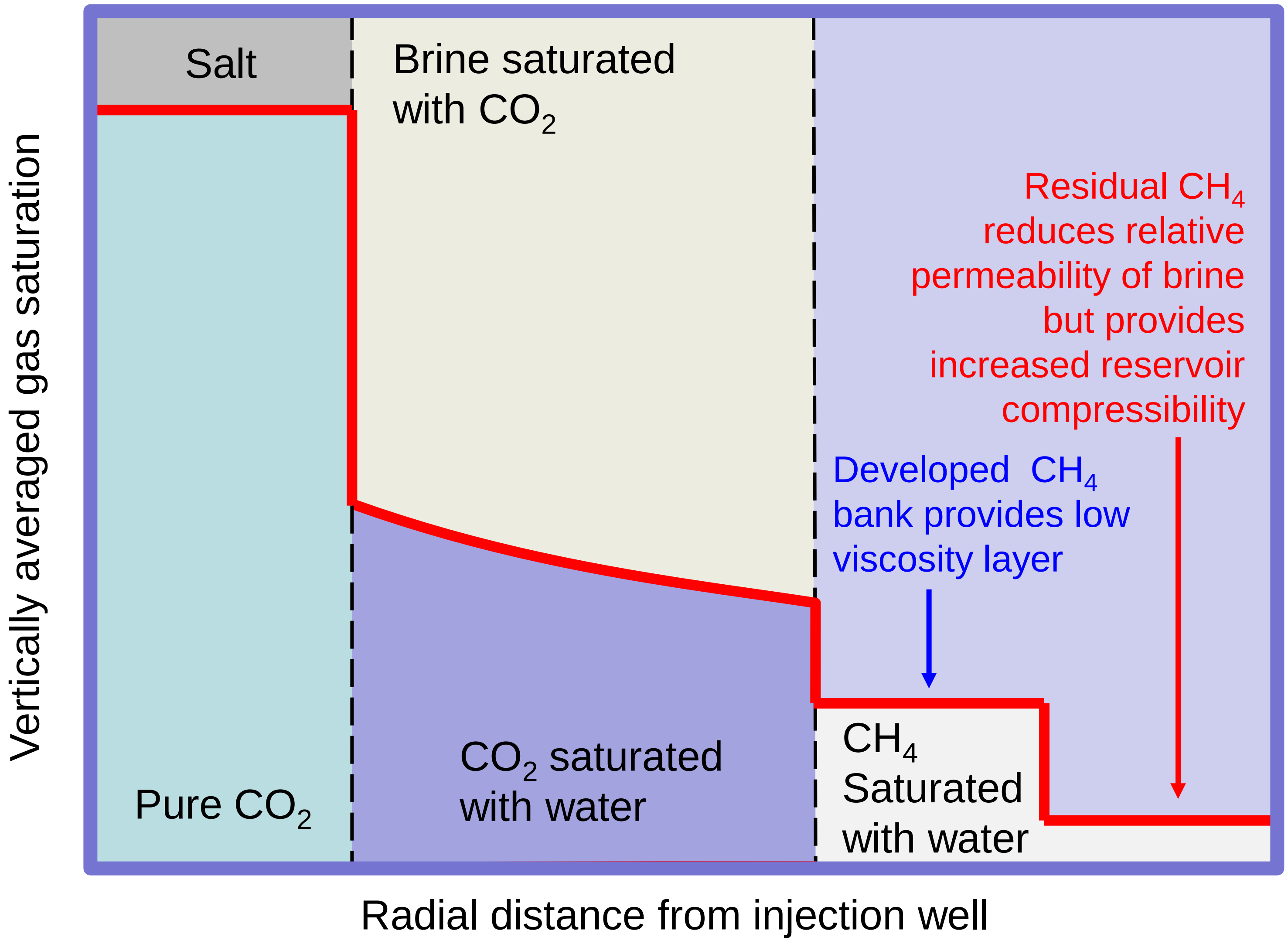
Fully immiscible displacement



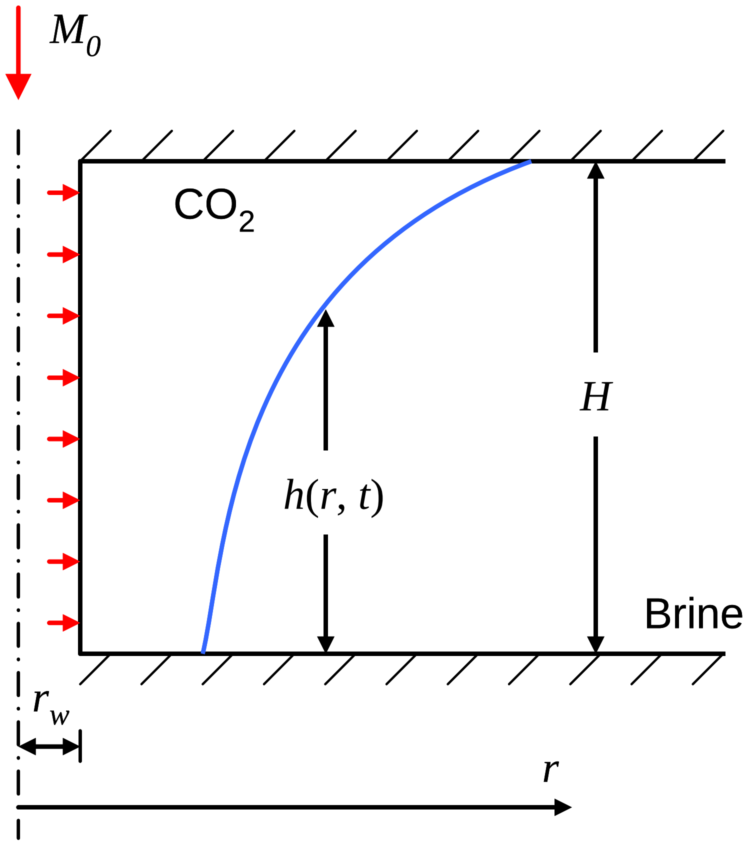
Partially miscible displacement



Residual and/or dissolved CH_4



Simplifying assumptions



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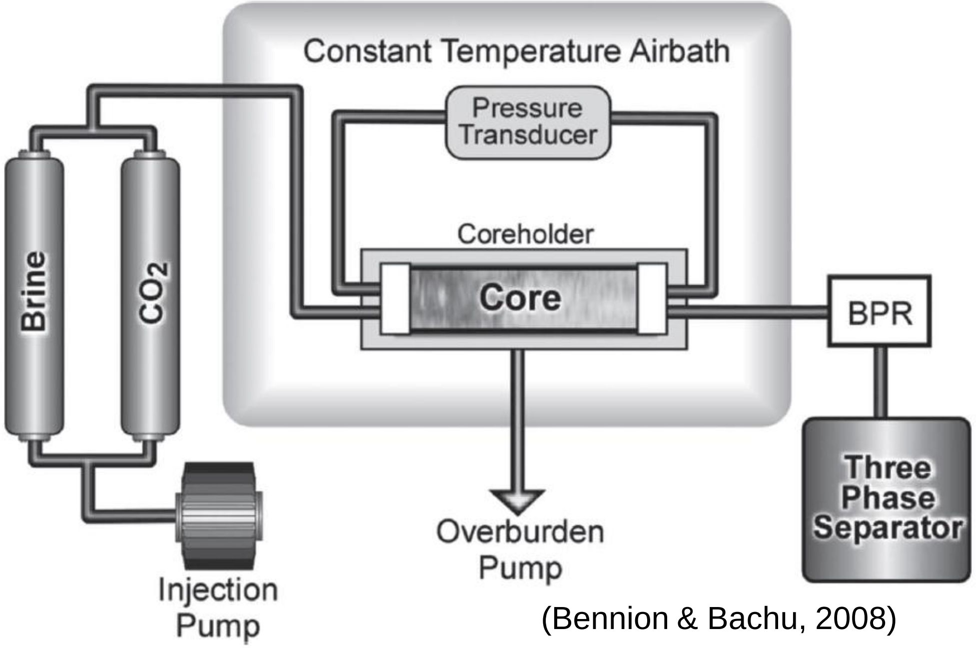
What is relative permeability?

When a porous medium is partially saturated with different fluid phases only a fraction of the intrinsic permeability is available to each fluid.

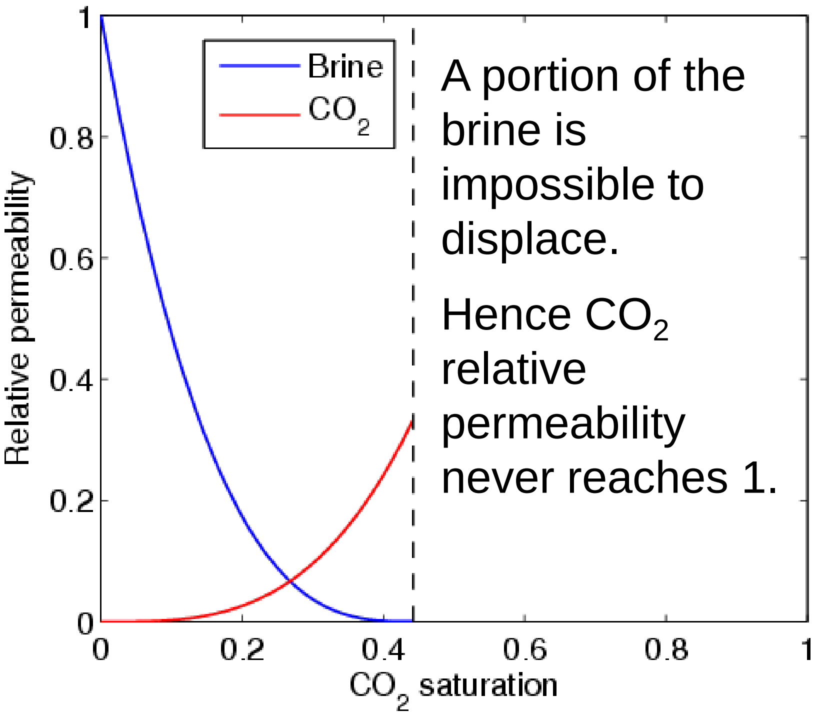
Relative permeability is this fraction.

Normally obtained from core-flood experiments.

Typical apparatus setup



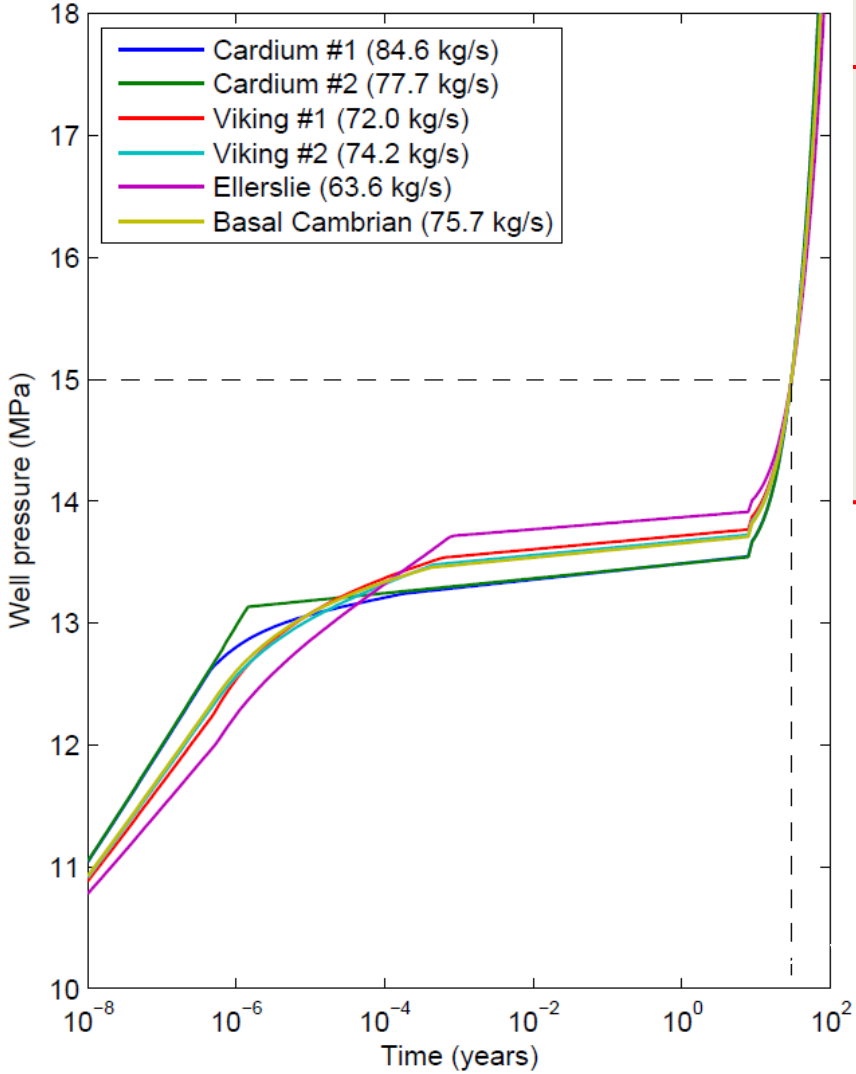
(Bennion & Bachu, 2008)



A portion of the brine is impossible to displace.

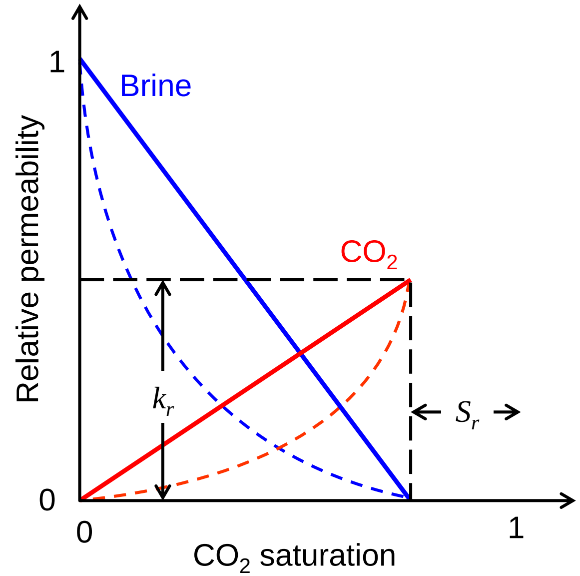
Hence CO_2 relative permeability never reaches 1.

Bennion and Bachu's six sandstone cores

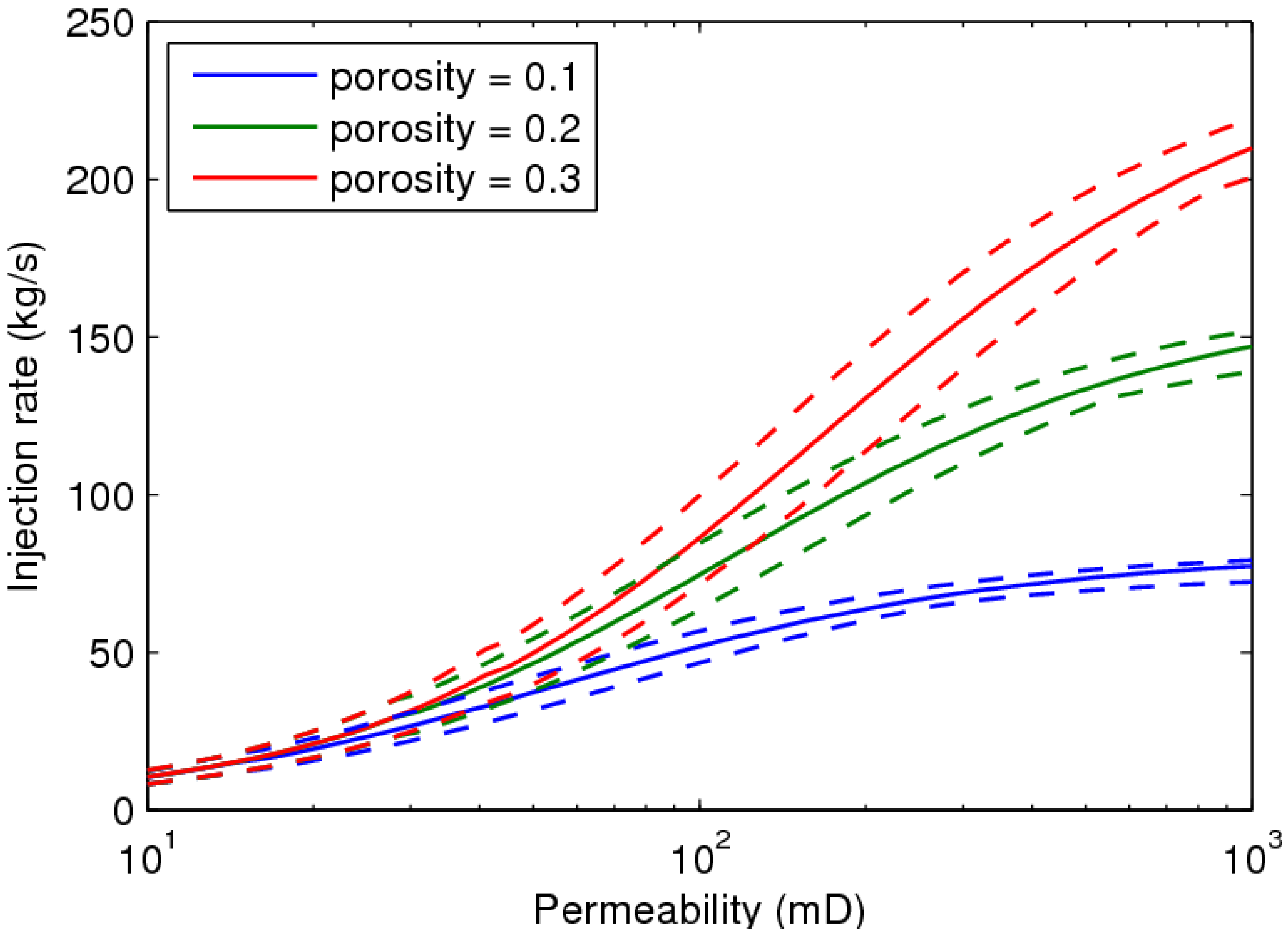


Some data for sandstones (after Bennion and Bachu, 2009)

	k_r	S_r	Brine exp	CO_2 exp
C1	0.53	0.20	1.3	1.7
C2	0.13	0.43	1.2	1.3
V1	0.33	0.56	2.9	3.2
V2	0.26	0.42	1.7	2.8
E	0.12	0.66	2.1	2.2
BC	0.54	0.29	1.8	5.0



Sensitivity to uncertainty in rel-perm data



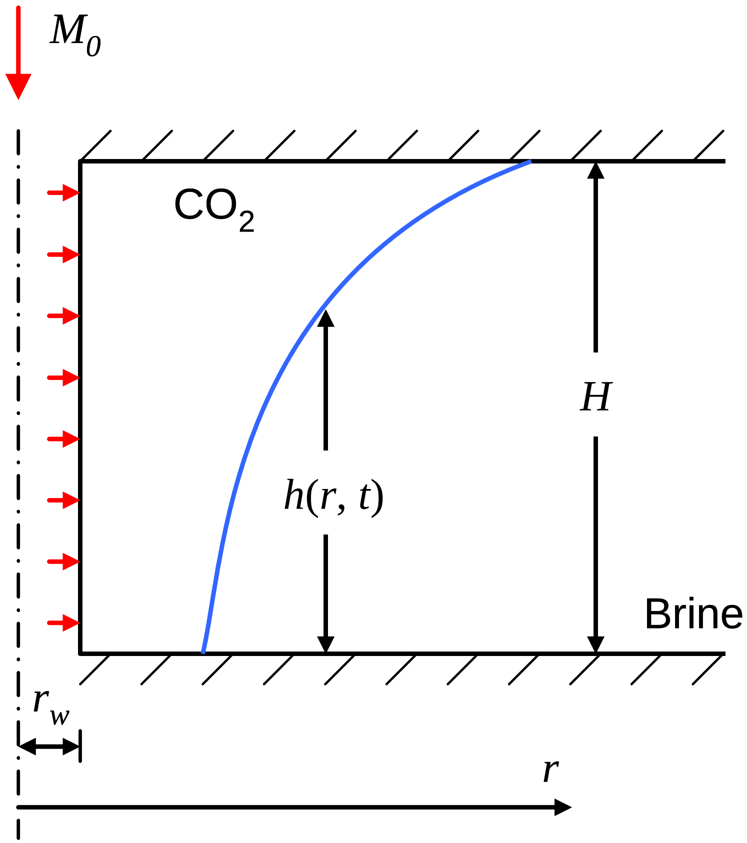
Pressure change = 5 MPa

Temperature = 40°

Formation thickness = 200 m

Formation area = 1250 km²

Simplifying assumptions



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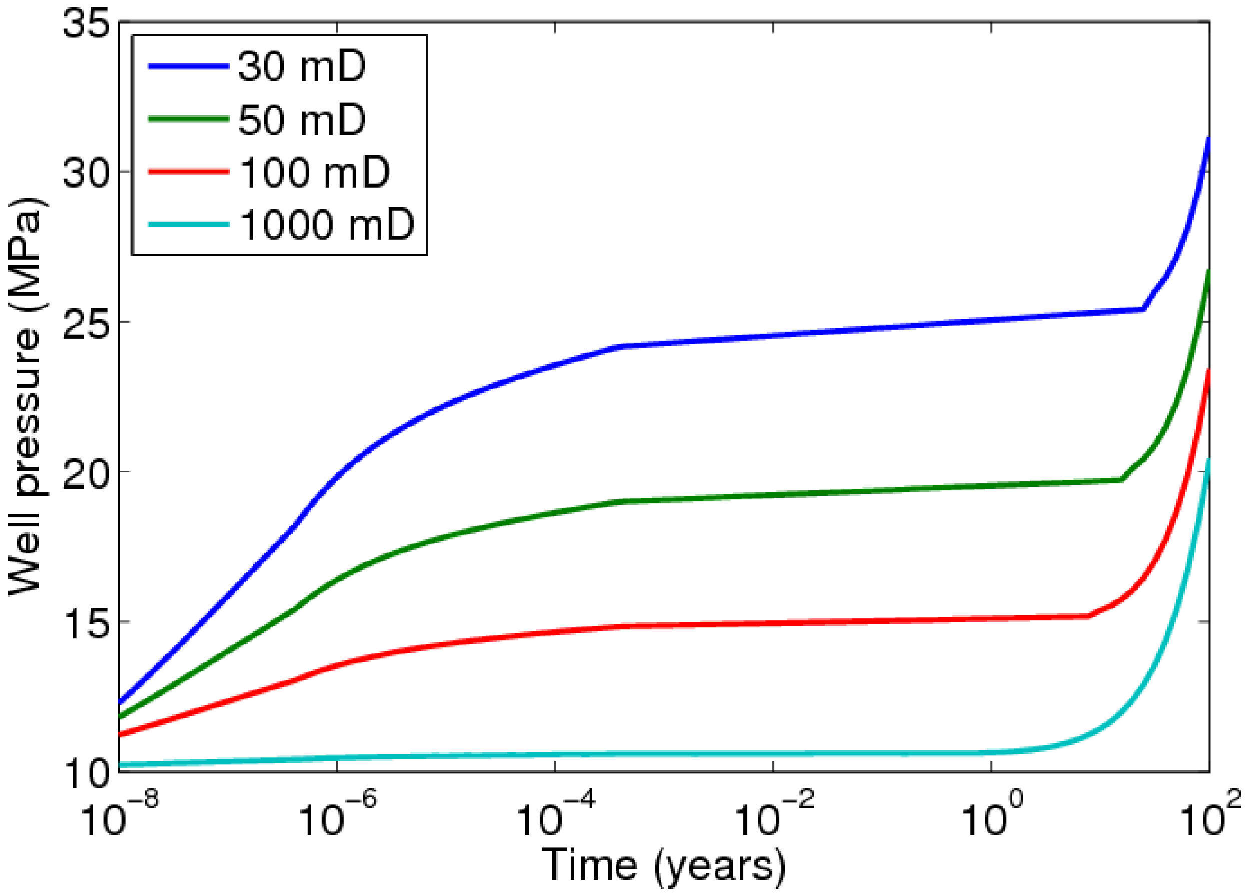
Effect of permeability on pressure



Injection rate = 3 Mt/yr

Formation thickness = 200 m

Porosity = 20%

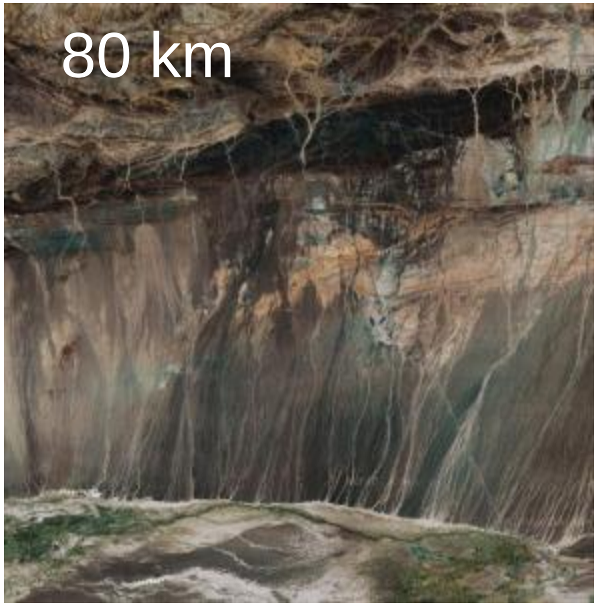
Formation area = 1250 km^2

Stochastic simulation of channels

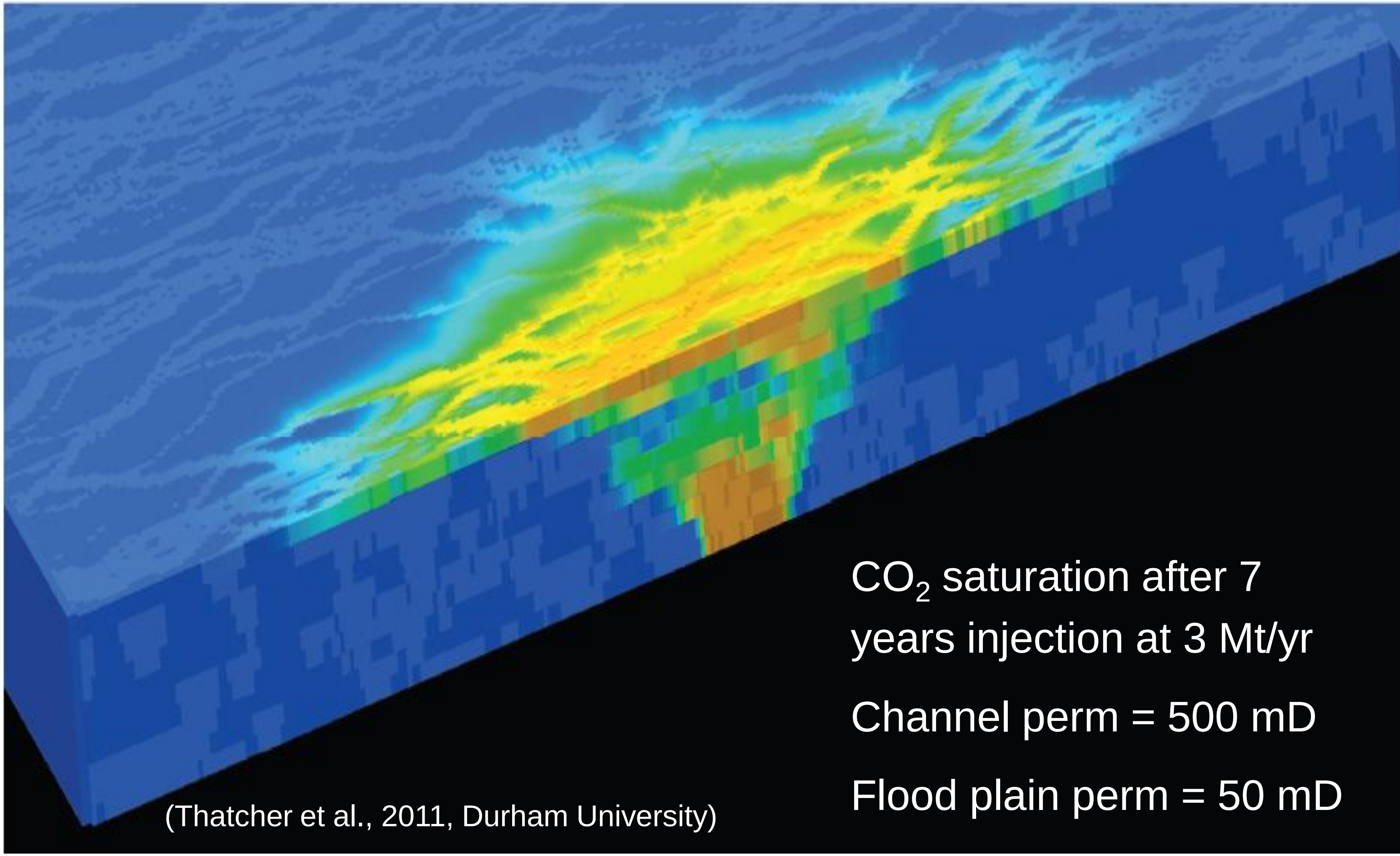
Bunter sandstone outcrop

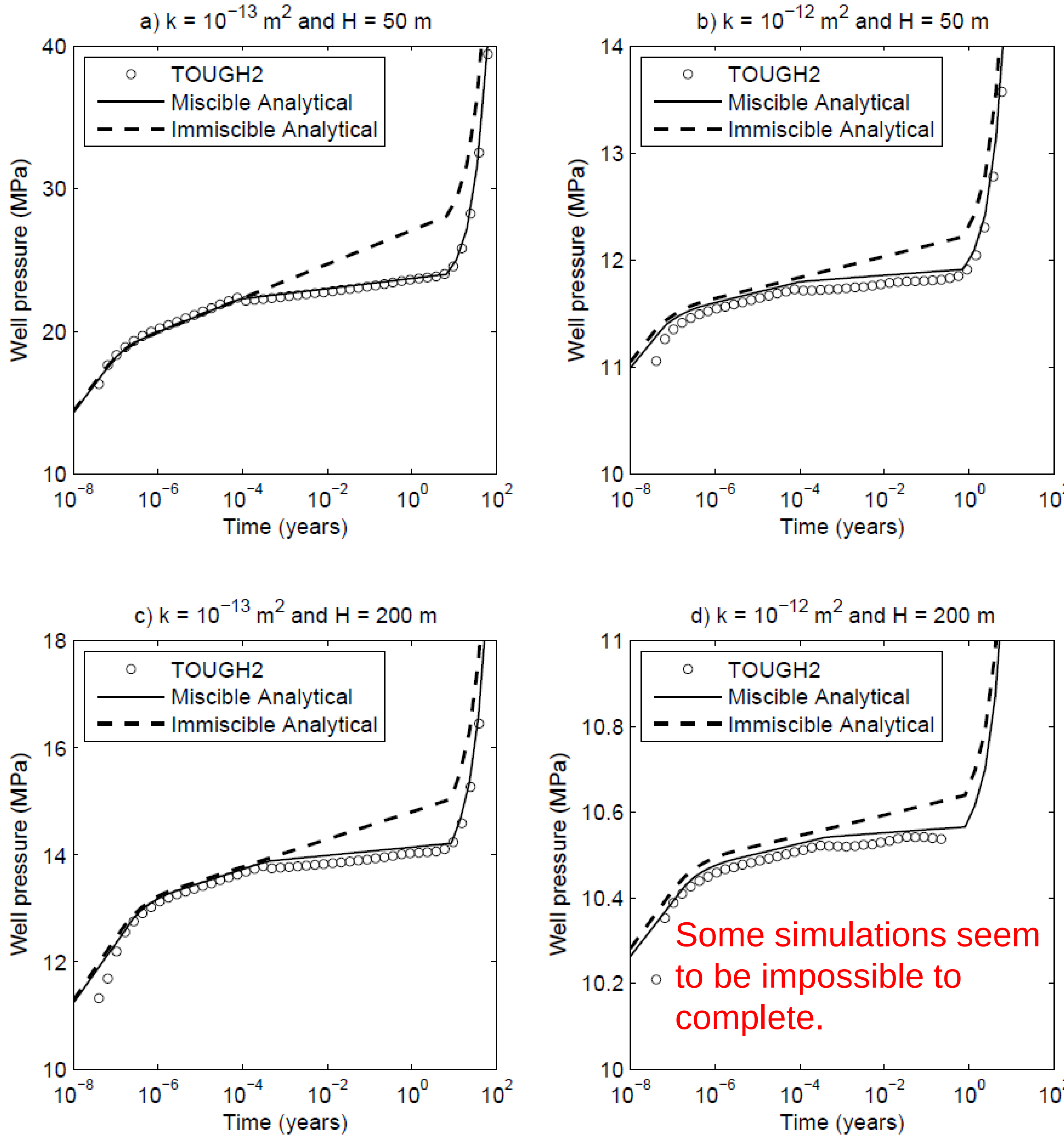
- Fluvial channels deposited in an arid environment of alluvial fans.
- Similar to Tarim Basin, China.

Channel widths 10s to 100s meters. Need grid cells around 5 x 5 m to resolve channel structures.



Influence of permeability





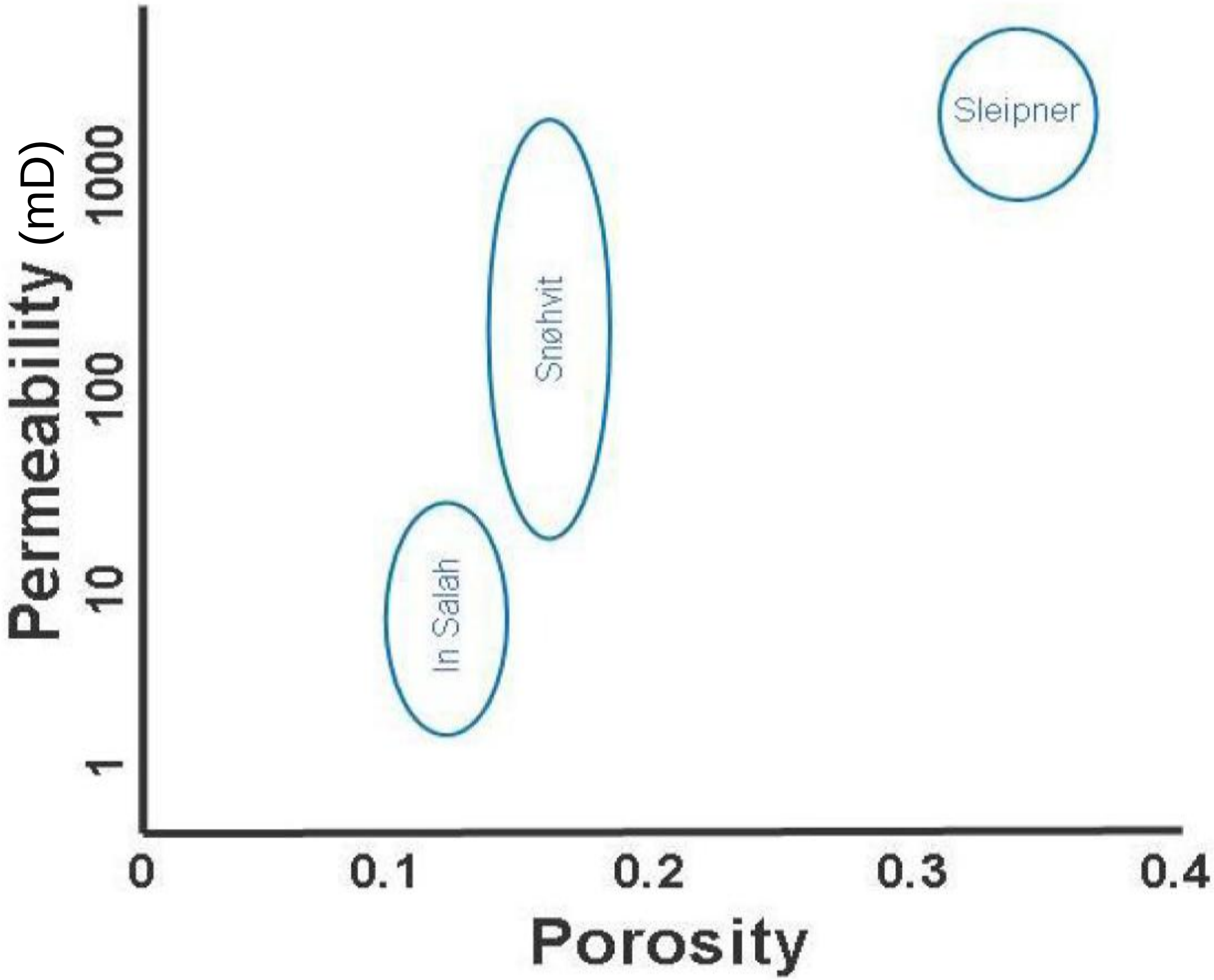
a) k = 10^-13 m^2 and H = 50 m
b) k = 10^-12 m^2 and H = 50 m
c) k = 10^-13 m^2 and H = 200 m
d) k = 10^-12 m^2 and H = 200 m
TOUGH2
Miscible Analytical
Immiscible Analytical
Well pressure (MPa)
Time (years)
Some simulations seem to be impossible to complete.

Snohvit Project, North Sea

- Snøhvit (Snow White) is an LNG project, in the Barents Sea offshore Norway
- CO_2 is captured onshore and transported in a 153km subsea pipeline to a subsea template.
- The CO_2 is injected at a depth of 2600m into the Tubåen formation (below the gas reservoir).
- Injection of CO_2 started in 2008, and so far 1.0 Mt have been stored.

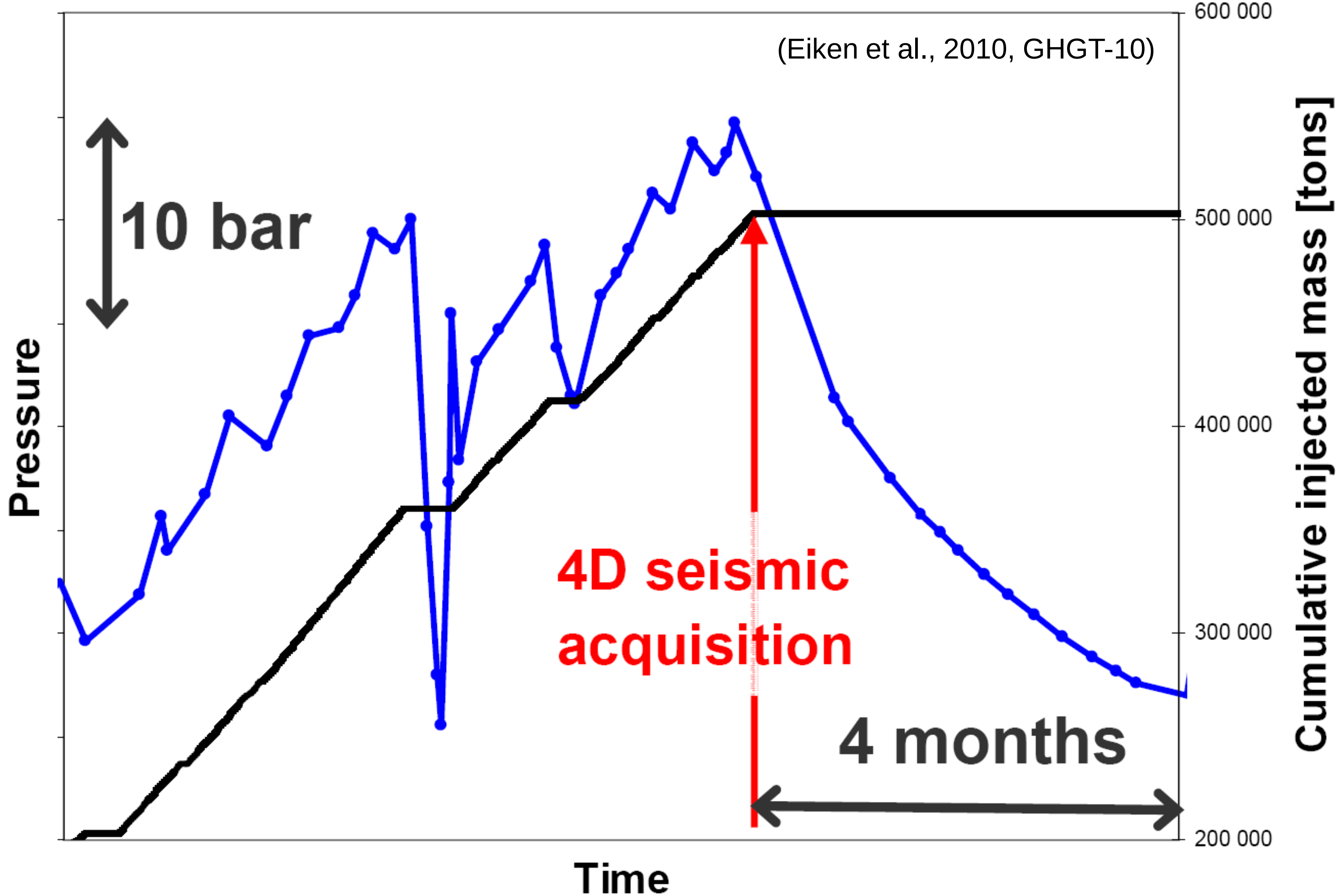
(Ringrose et al., 2011, CSLF Workshop)

Permeability of demonstration projects



(Eiken et al., 2010, GHGT10)

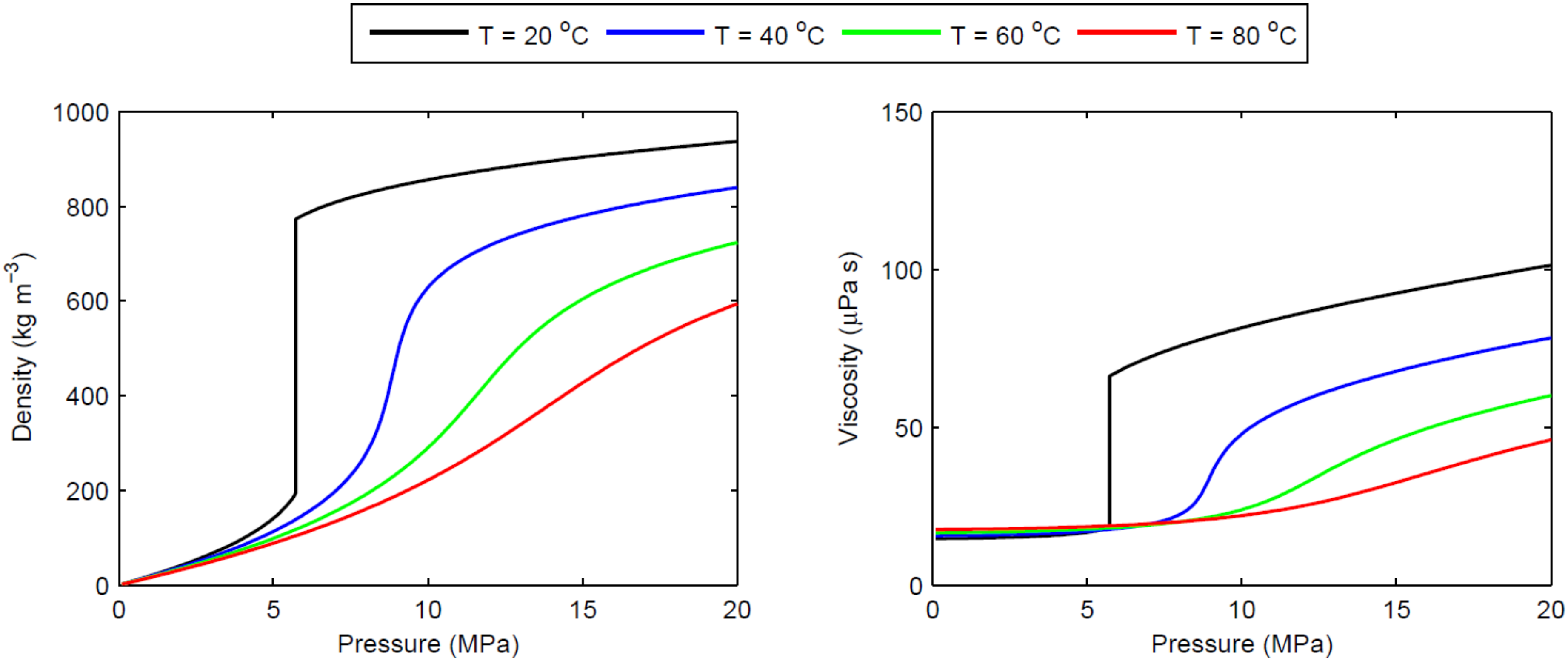
Pressure record from Snohvit



Summary and conclusions

- Storing UK emissions may involve drilling 1000s of wells but cost of drilling is likely to be trivial compared to capture costs.
- Salt precipitation around injection wells is likely to occur but is likely to be compensated for by evaporation of residual brine.
- There is major uncertainty concerning relative permeability of CO_2 brine mixtures. But associated uncertainty appears less significant for injectivity in the context of permeability and porosity uncertainty.
- Fine-scale heterogeneity (10 m scale) is likely to be important, but investigating this further has been challenging using available simulation methods.

Fluid properties of CO_2



Typical vertical profile