Handling pressure constraints and geomechanical limits for large-scale CO_2 storage projects

Philip Ringrose

Equinor Technology, Digital and Innovation
& Norwegian University of Science and Technology (NTNU)

SFI Centre for Geophysical Forecasting

Is large-scale CCS realistic?

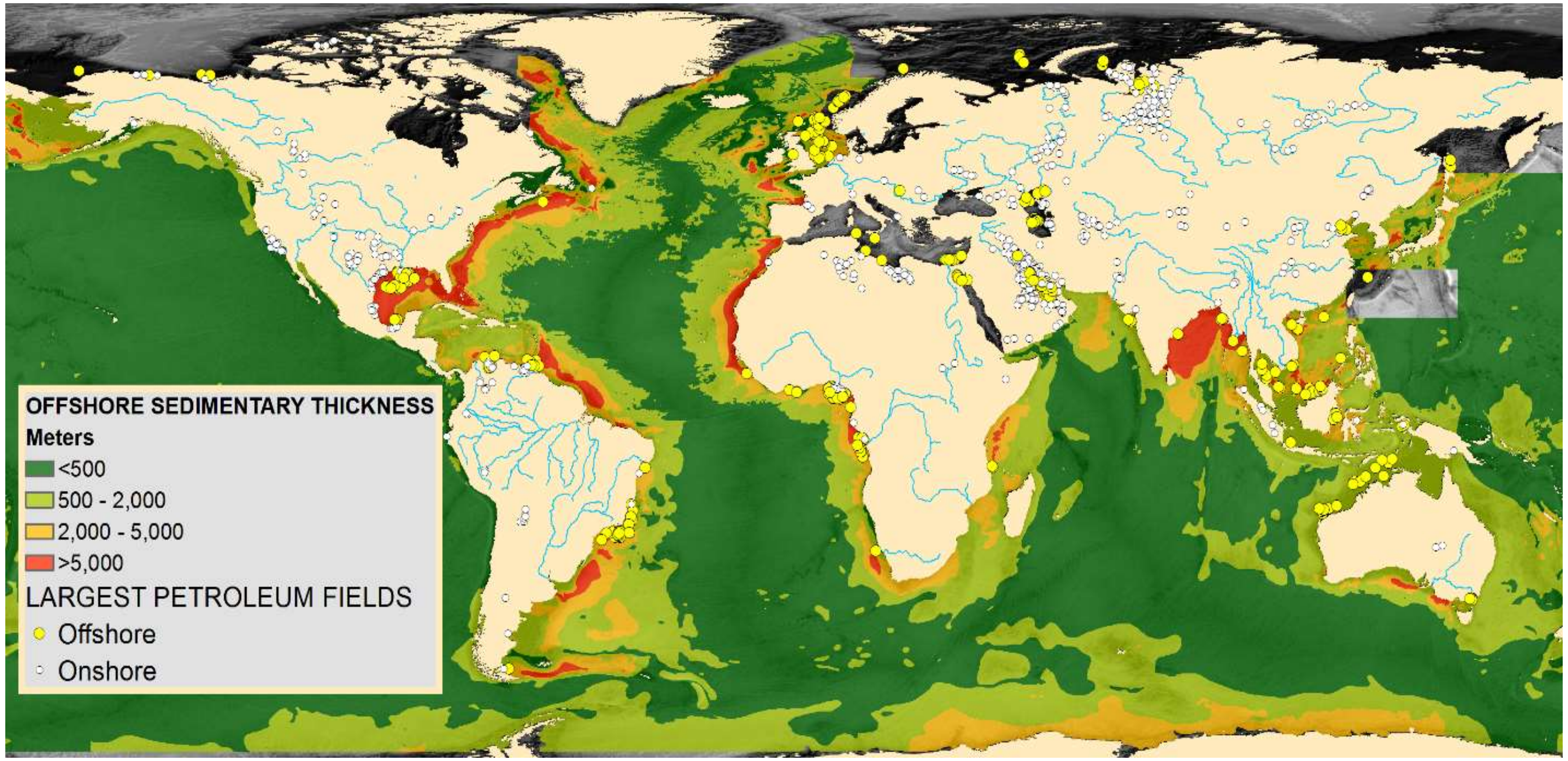
Recent study by Ringrose & Meckel (2019) on offshore global CO_2 storage resources
https://www.nature.com/articles/s41598-019-54363-z

- Uses basin geo-pressure approach
- Projected growth of CO_2 injection wells from historical hydrocarbon well developments
- Captures 'industrial maturation' phases for global CO_2 storage

Main Conclusion:

- We will need ~12,000 CO_2 injection wells by 2050 to achieve 2Ds goal

Each continental 'CCS hub' will need 100-200 wells in the next decade

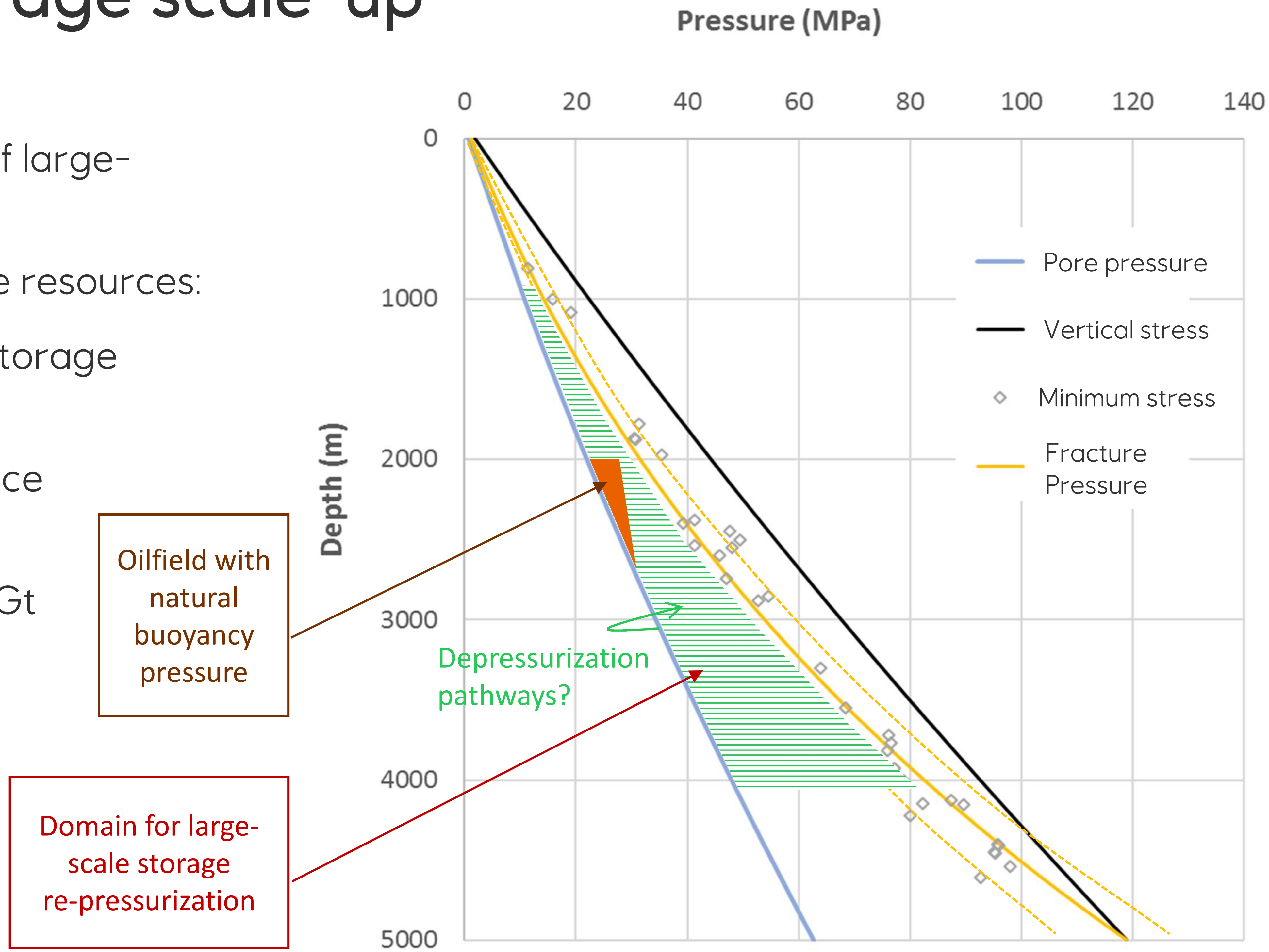


Global distribution and thickness of sediment accumulations on continental margins, with largest oilfields and main river systems (Ringrose & Meckel, 2019)

Key questions for storage scale-up

Much discussion about the 'do-ability' of large-scale storage:

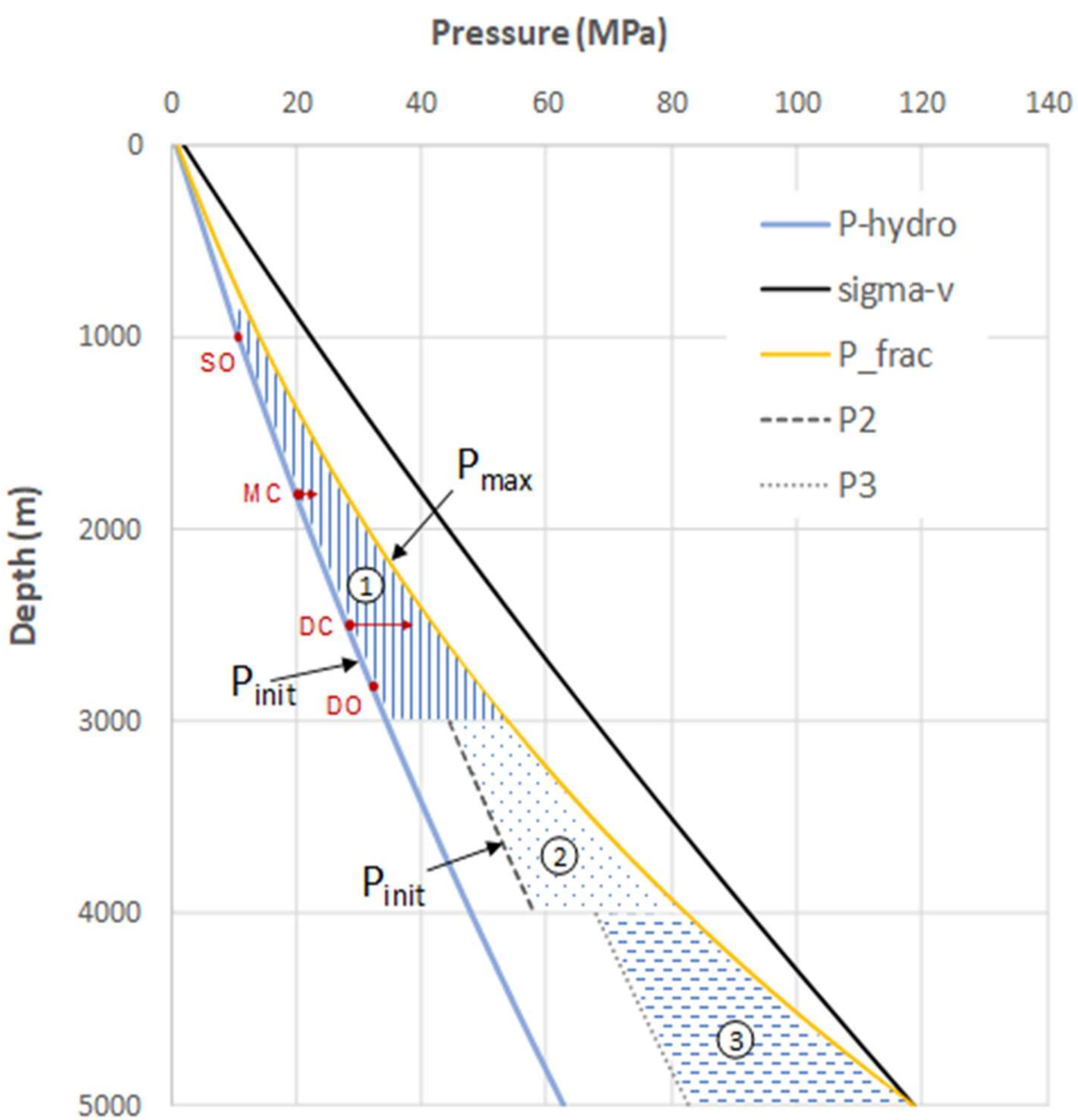
1. Many nations have mapped storage resources:
   - Mapped North Sea basin CO_2 storage resource is 160 Gt
   - North American storage resource is >2400 Gt
   - So far, we have only used 0.02 Gt of these resources (globally)
2. However, large-scale storage will require a pressure management approach



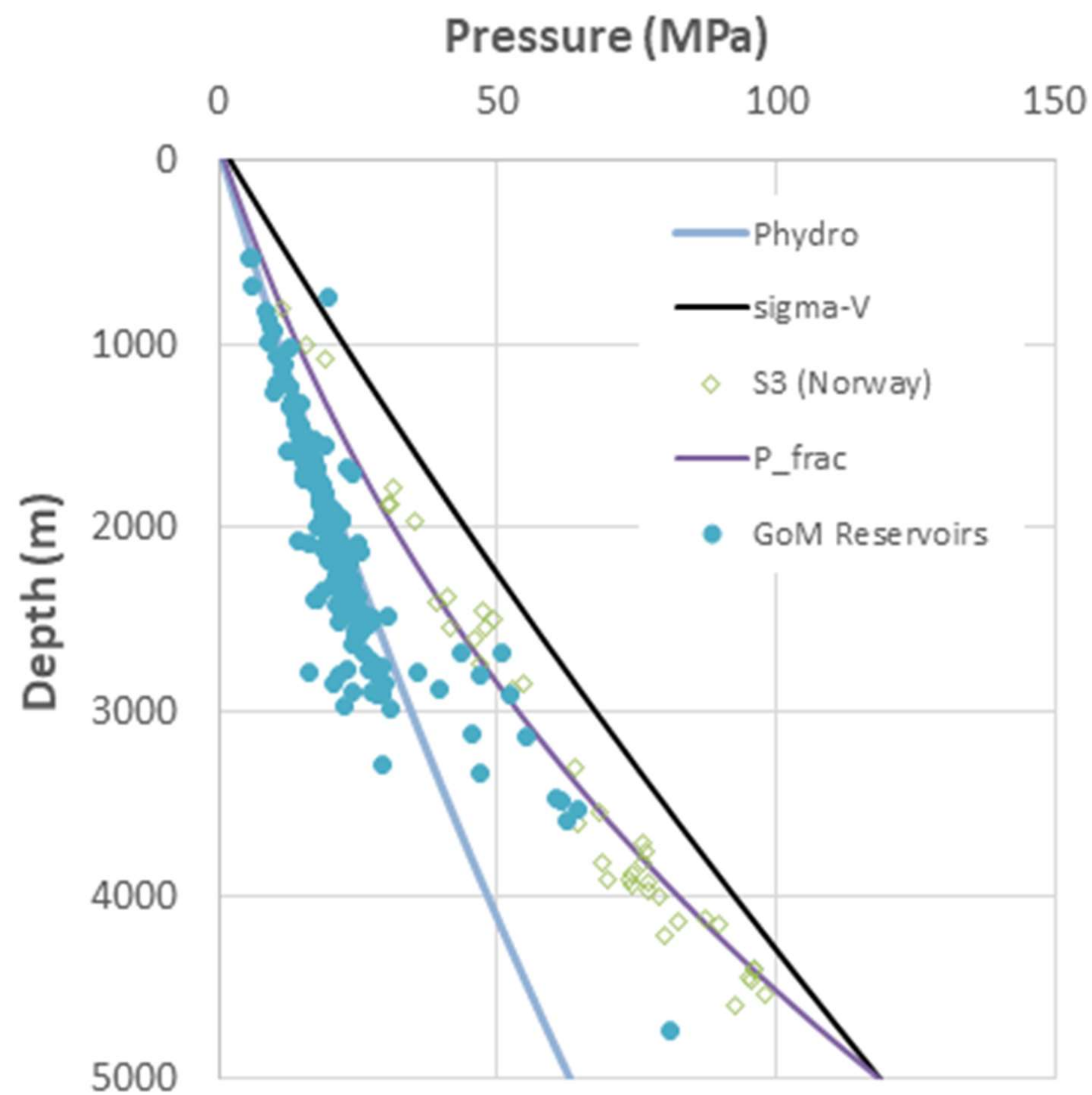
Ringrose & Meckel (2019); minimum stress data from Bolaas and Hermanrud (2003)

Basin Geo-pressure Concept

Review of basin pressure data from Norway datasets

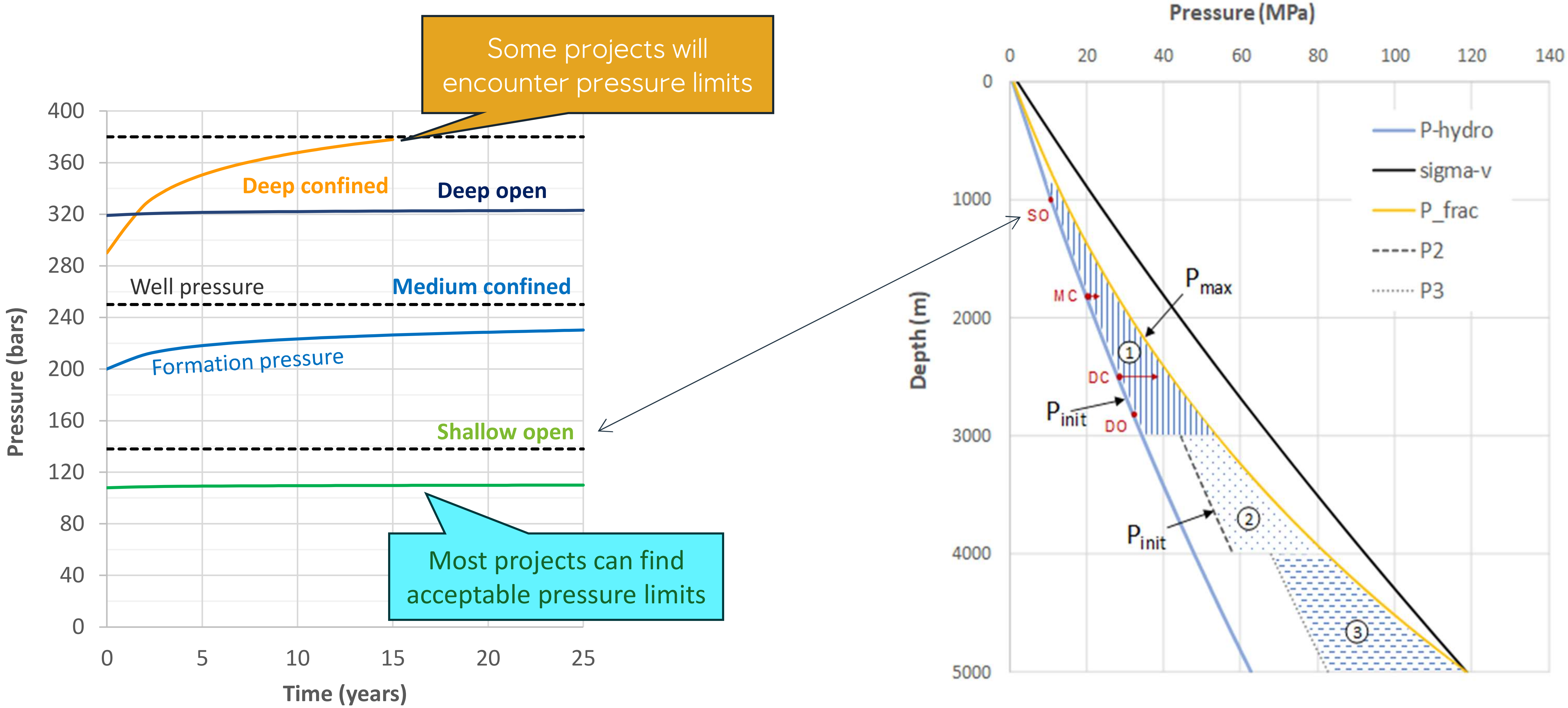


Comparing Gulf of Mexico with NCS



Scenarios within the geo-pressure framework

- Let´s hypothesize some scenarios within the basin geo-pressure framwork



Pressure management approach for CO_2 injection projects

➢ Assumption: Initial and final pressure per well can be used to estimate capacity

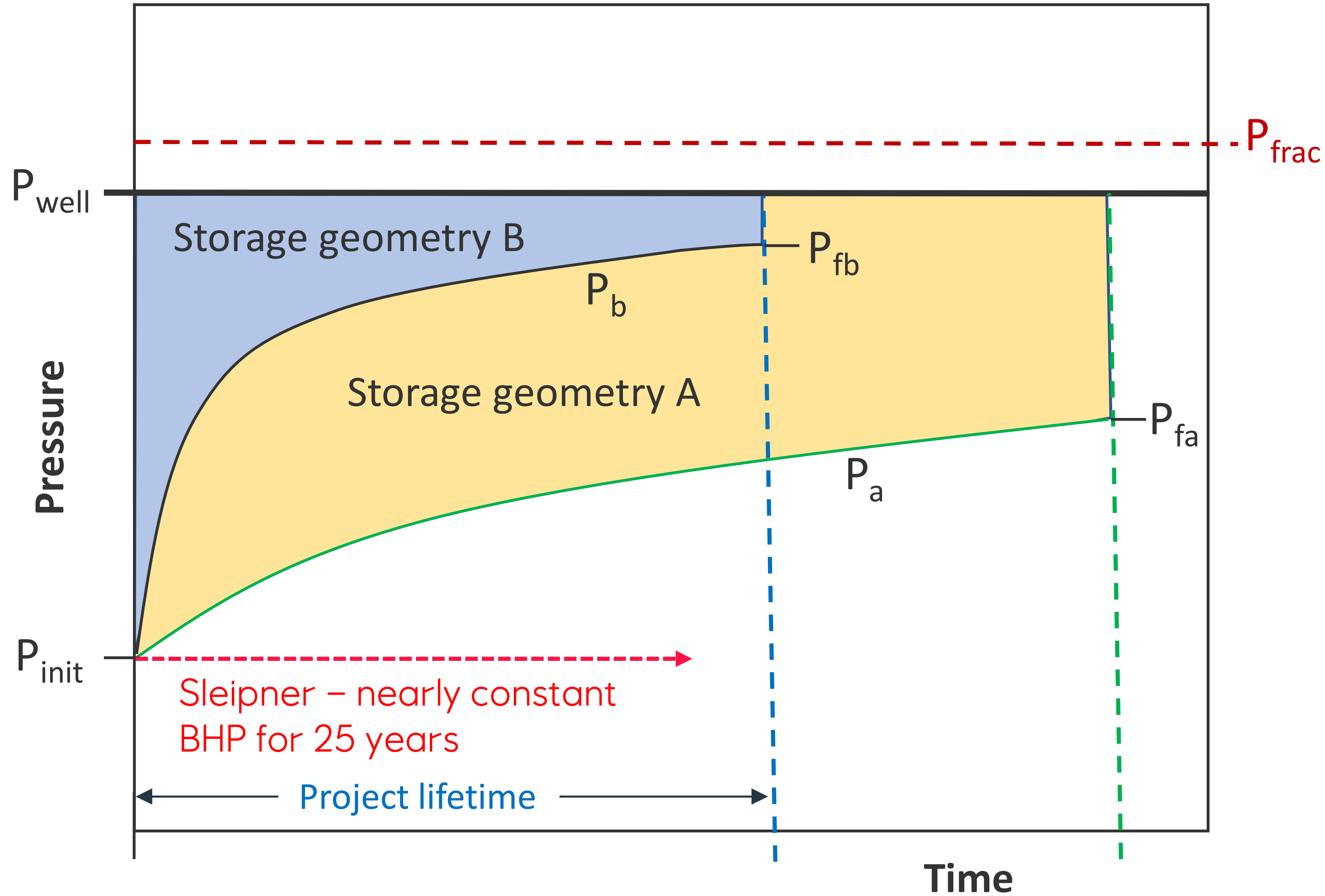


Fig. 5 Idealized CO_2 storage project lifetime pressure plots for two contrasting aquifer units assuming the same initial pressure conditions.

Generic 'basin ΔP' approach:

Integration of the injectivity equation over the project lifetime:

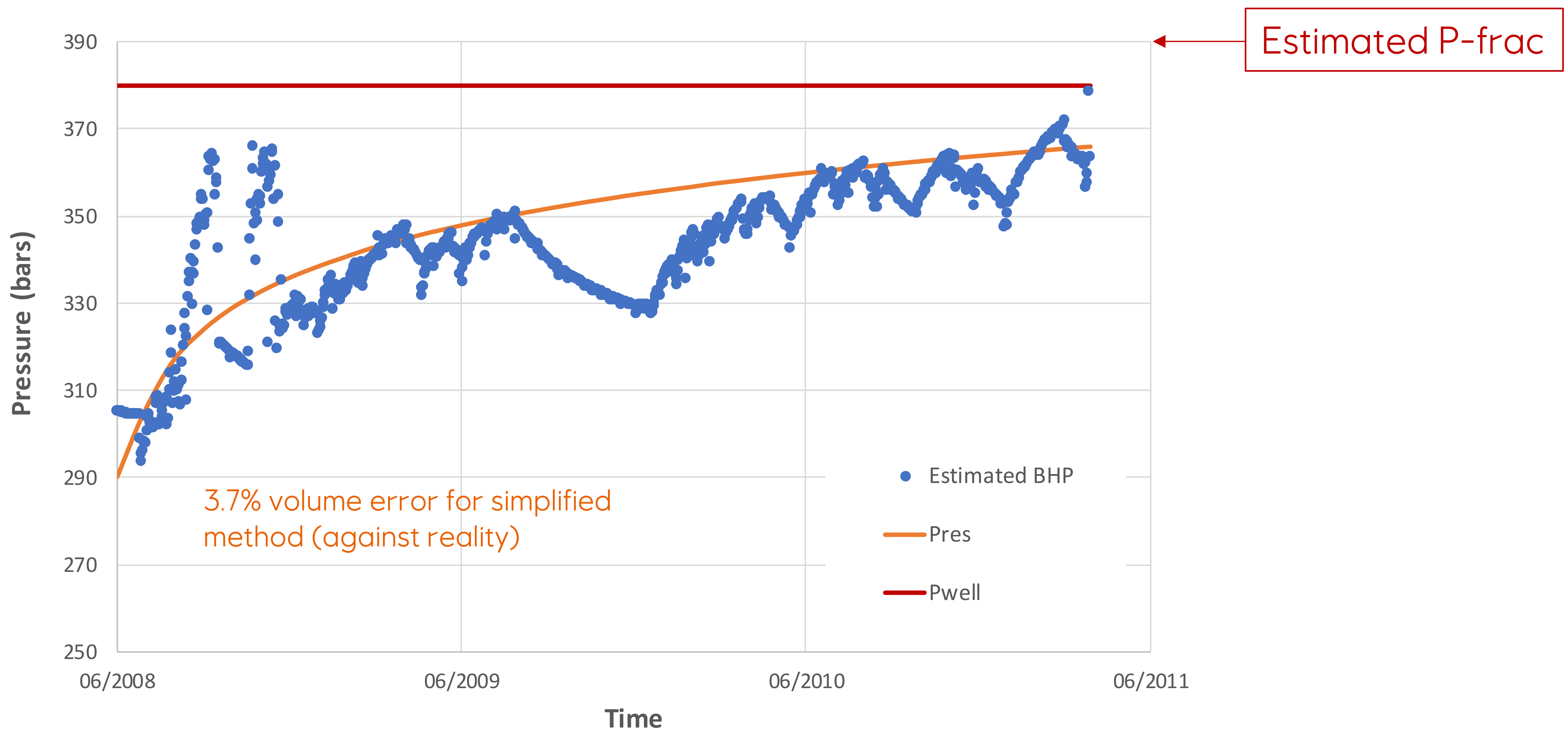
$$V_{project} = I_C \left[p_{well} - p_{init} + \int_i^f A\, p_D(t_D) \right] + F_b$$

where,

$V_{project}$	= estimated volume stored
I_c	= injectivity
P_{well}	= injection well pressure
P_{init}	= initial reservoir pressure
$Ap_D(t_D)$	= characteristic pressure function
F_b	= volume flux boundary condition

Validation of method for the Snøhvit (Tubåen) case

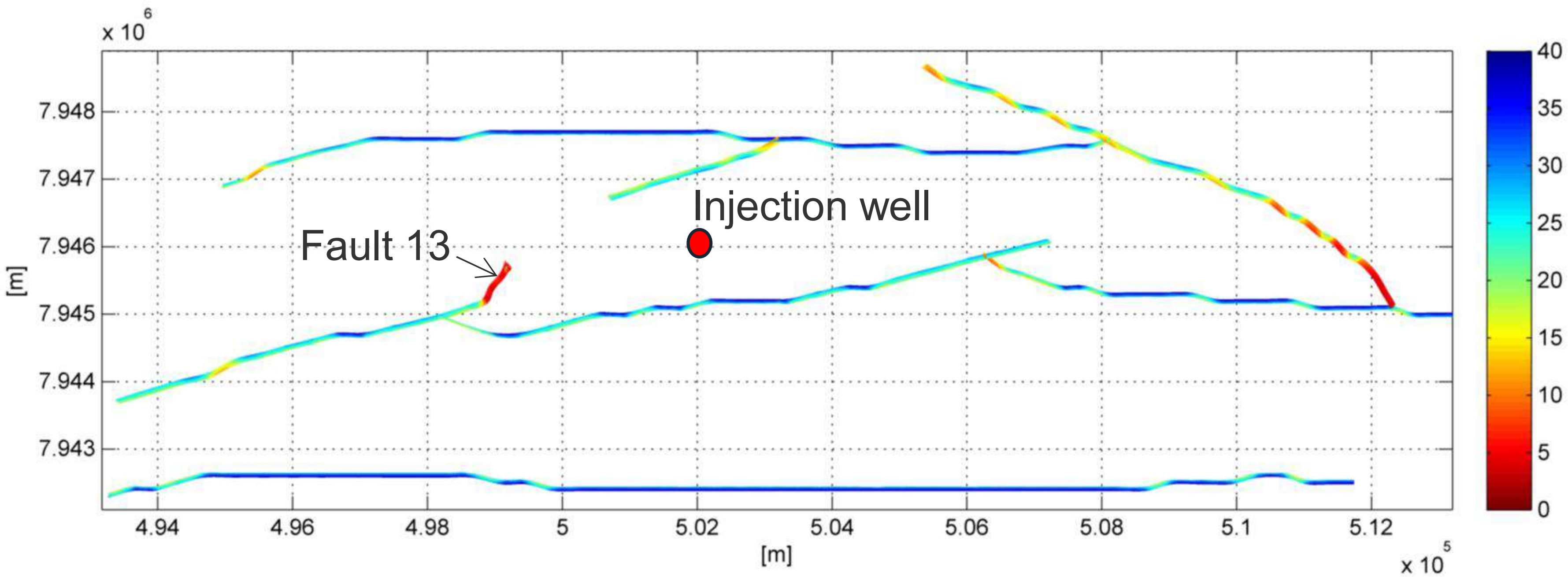
- Analytical function fitted to CO2 injection data for Snøhvit FH2 injection (Tubåen formation)



So, what about the geomechanical risks?

- Informative case study in the Snøhvit CO2 injection case: Chiaramonte et al. (2015) *J. Geophysical Research: Solid Earth*
- Significant uncertainties in stress field estimates, but group modelled fault-slip risk for range of scenarios
- Main storage issue is to be sure about the most 'slip-prone' faults

Modelled fault traces color-coded by the extra pressure, P_{cp} (MPa), necessary to initiate slip in base-case scenario (Chiaramonte et al. 2013)



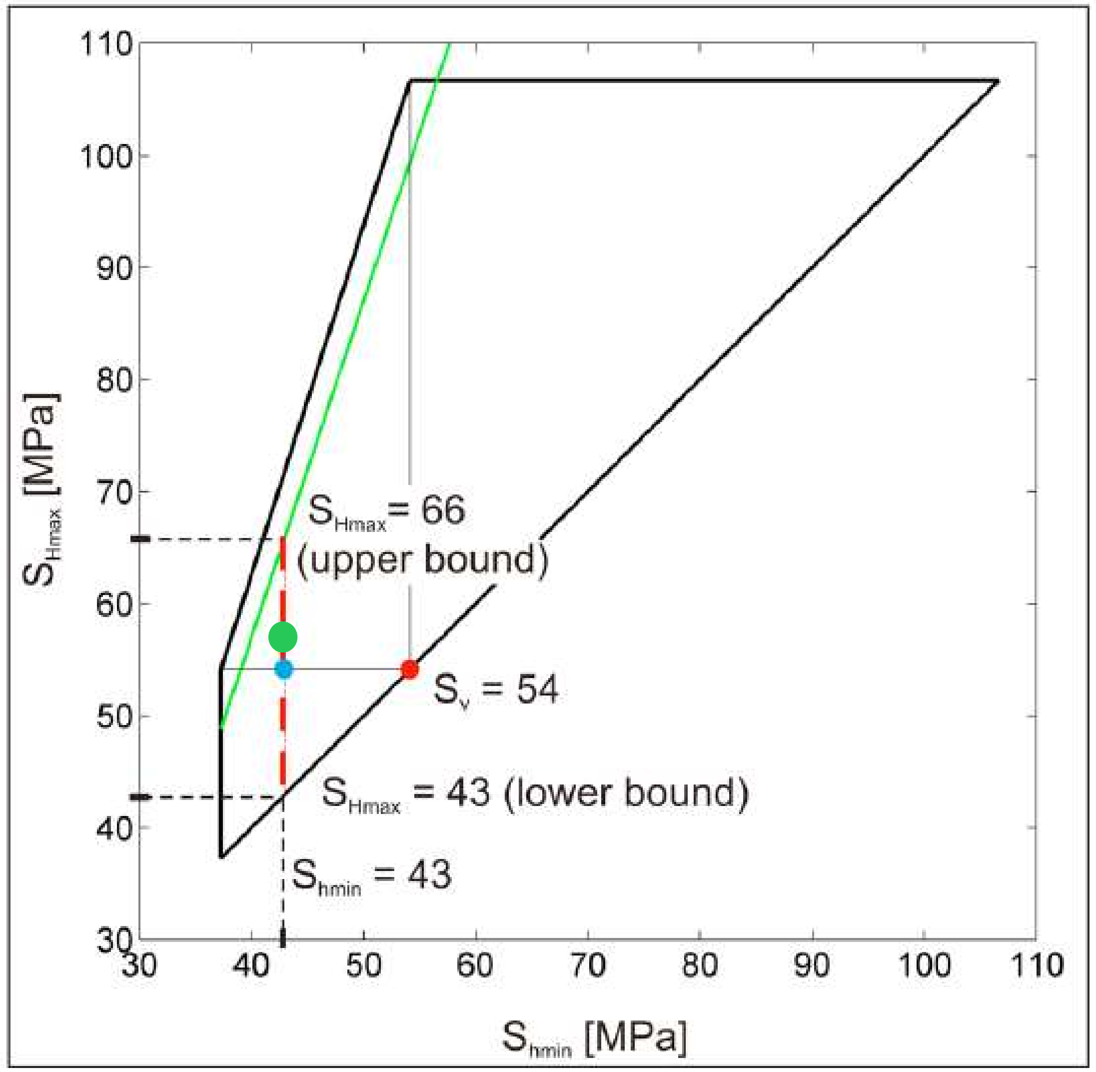


Figure 7. Representation in a stress polygon of the possible magnitudes of S_{Hmax} (red dotted line) for a given S_{hmin} (43 MPa) at the top of the Tubåen 1 (2683 m), for a given pore pressure (29.6 MPa) and assumed coefficient of friction ($\mu = 0.6$). The green line corresponds to the possible magnitudes of S_{Hmax} as a function of S_{hmin} that is required to cause drilling-induced tensile fractures (DITF) in a vertical well, considering temperature and mud-weight effects. The S_{Hmax} range was derived from equations (1) and (2). The blue dot represents the arbitrarily chosen S_{Hmax} magnitude for the base case scenario (S_{Hmax} = 54 MPa).

 Open

In-depth analysis of stress-pressure-strain interactions

Minimum stress is estimated from leak-off tests (LOT) and ideally an extended X-LOT (Raaen et al. 2006; Bohloli et al. 2017)

- Should be fairly accurate measurement, but:
  - Not always available in the rock formations of interest
  - Often regional/nearby tests are used

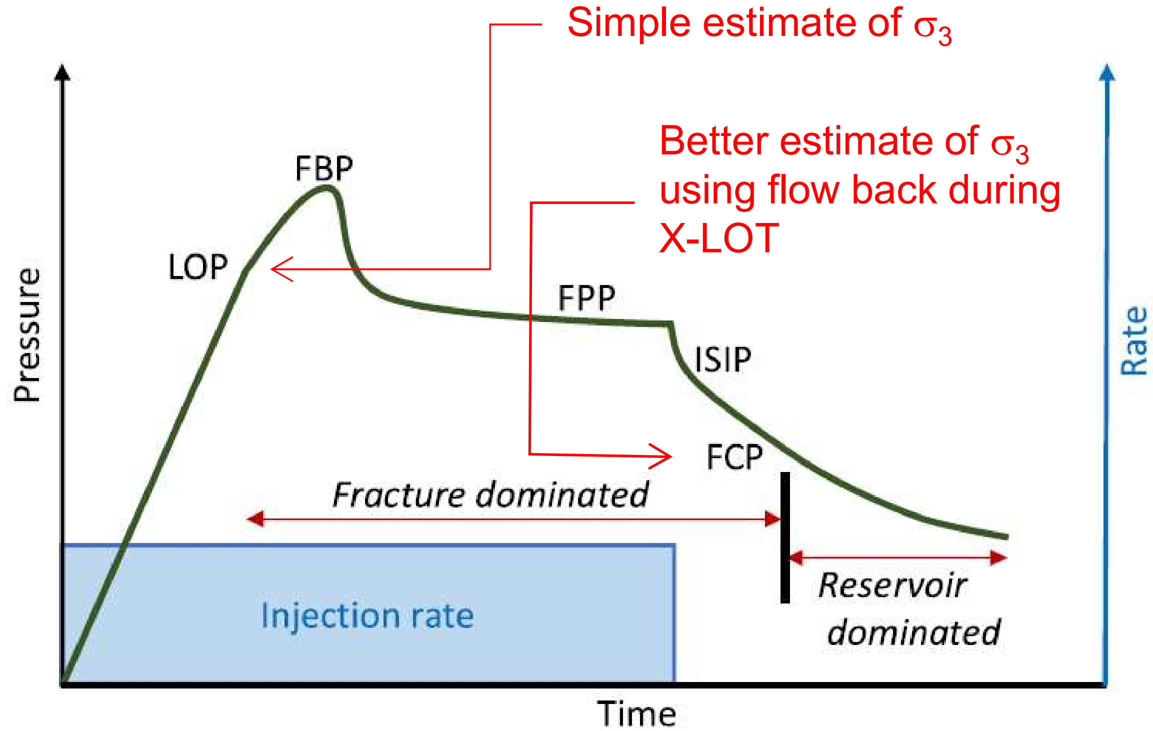
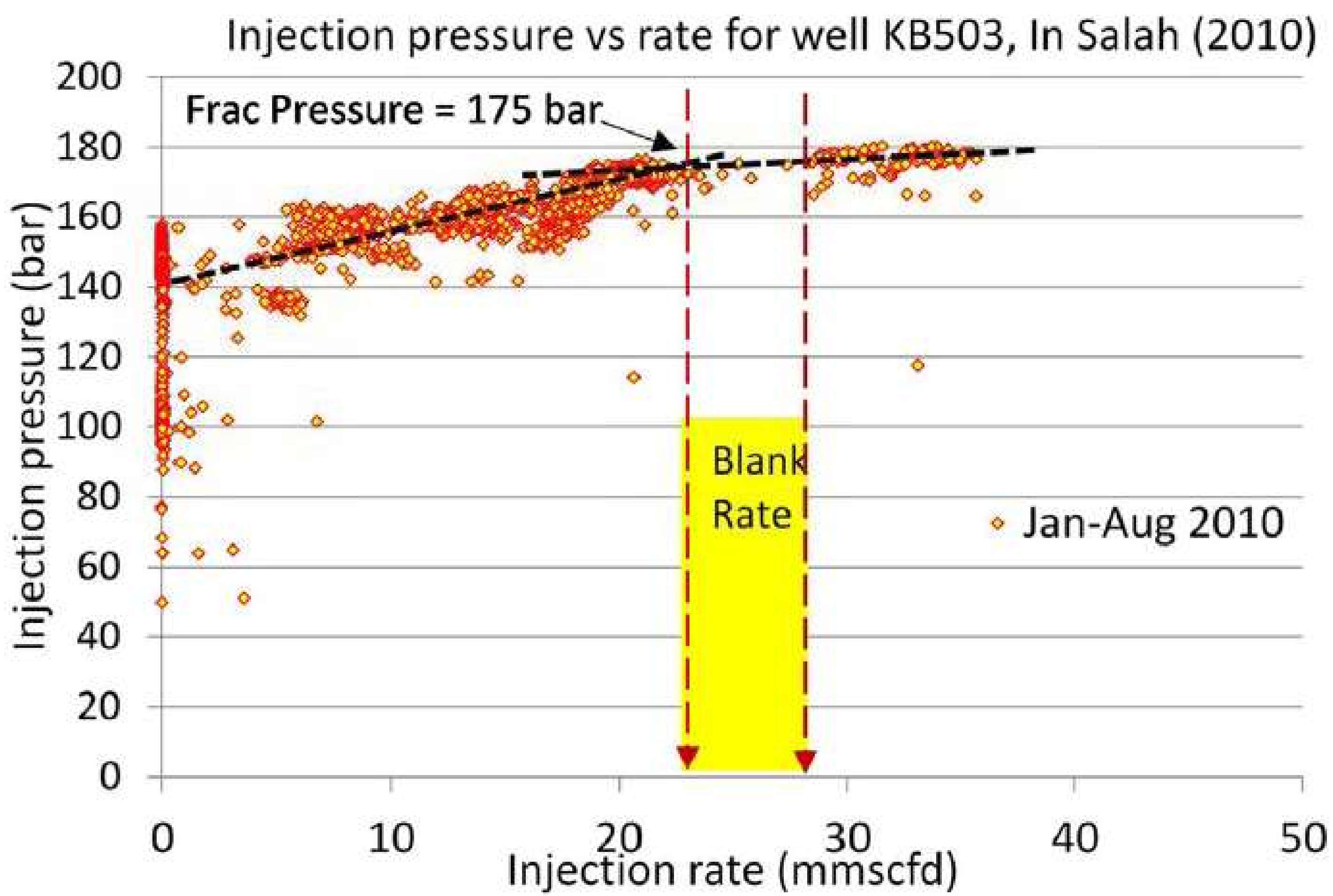


Fig. 1. A schematic Minifrac test showing pressure and rate versus time. For a leak-off test, injection time is much shorter than that shown in the figure. LOP = leak-off pressure, FBP = fracture breakdown pressure, FPP = fracture propagation pressure, ISIP = instantaneous shut-in pressure, FCP = fracture closure pressure. Fracture dominated vs. reservoir dominated flow range are indicated by arrows.

Determination of P_f from injection time-series

- Plot of injection pressure versus rate for KB-503, In Salah.
- Crossover point and blank-rate interval reveal the in situ fracture pressure

B. Bohloli et al. / International Journal of Greenhouse Gas Control 61 (2017) 85–93



Summary

1. Phil and Tip have a 'can-do' attitude to global CCS !
2. Argue for a basin pressure management and optimization approach
3. Most projects (Class A aquifers) will not have serious pressure limit problems
4. The projects that do have pressure limits (Class B aquifers) will need careful pressure management during the operational lifetime
5. For geomechanical risks, stress-aligned slip-prone faults/fractures are the top issue
6. Accurate determination of the stress field and stress tensor is usually a big challenge for CO_2 storage projects