Reservoir engineering of fractured systems (very brief overview)

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Fracture & Vuggy Porosity estimates

- Weber & Bakker (1981) SPE 10332

Using cores (31), outcrops (4), material balance (19), res eng (4), logs (3)

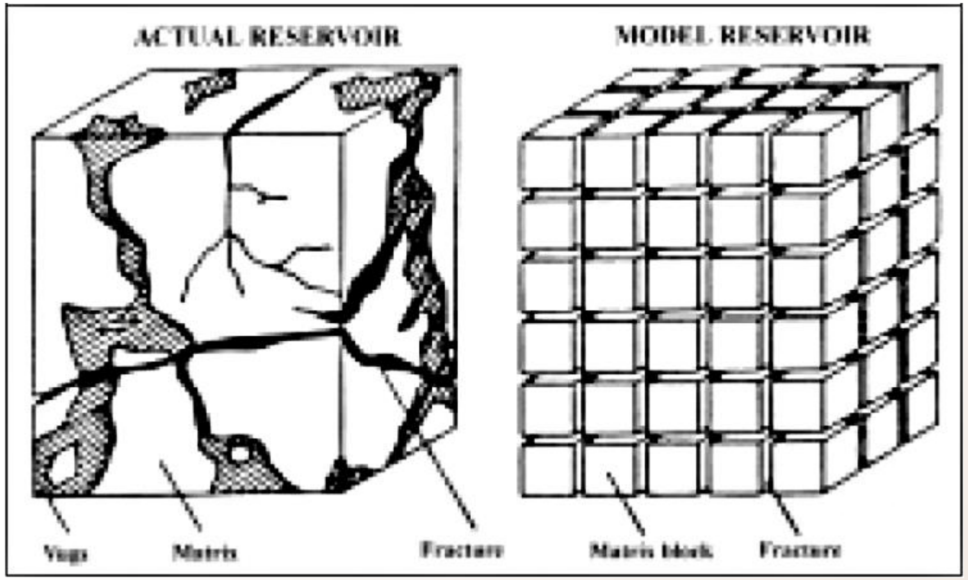
		No. of fields
• Monoclines & low-dip anticlines	0.01 - 0.1%	6
• Strongly folded anticlines	0.1 - 0.3%	13
• Enhanced by leaching	0.2 - 1.0%	9
• Karst aquifers, surface – shallow	0.2 - 3.0%	14
• Deeply buried brecciated karst/ collapsed breccias	0.5 - 2.0%	5
• Fractured chert	5.0 - 8.0%	1
• Fractured tuffs / igneous rocks	2.0 - 8.0%	3
		-
		51

- Van Golf-Racht 'Fundamentals of Fractured Reservoir Engineering'

From core and log analysis (unspecified)

• Macrofracture network	0.01 - 0.5%
• Isolated fissures	0.001 - 0.01%
• Fissure network	0.01 - 2%
• Vugs (in Karstic rock)	0.1 - 3%

Warren & Root dual porosity model applied to pressure build-up well-tests



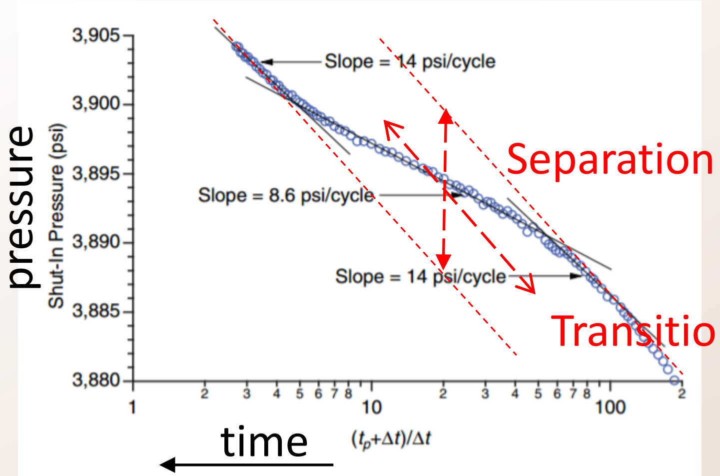


Fig. 2—Horner plot of the BU data given by Bourdet et al. (1983) after Kuchuk and Biryukov (2014).

Separation depends on ω

Transition time depends on λ

$$\lambda = \frac{\alpha . K_m . rw^2}{K_f}$$

Proportion of storage due to fractures

$$\omega = \frac{\phi_f C_f}{\phi_f C_f + \phi_m C_m}$$

What is fracture compressibility, C_f ??

Local fracture storage masks 1st straight line

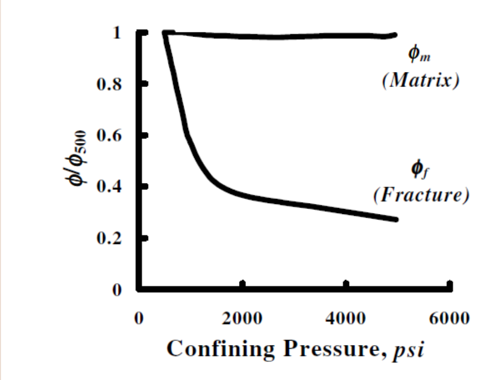


Fig. 1 Normalized porosity of the fractured and matrix systems as a function of hydrostatic confining pressure (After Nelson[8]).

Material Balance; example formulation

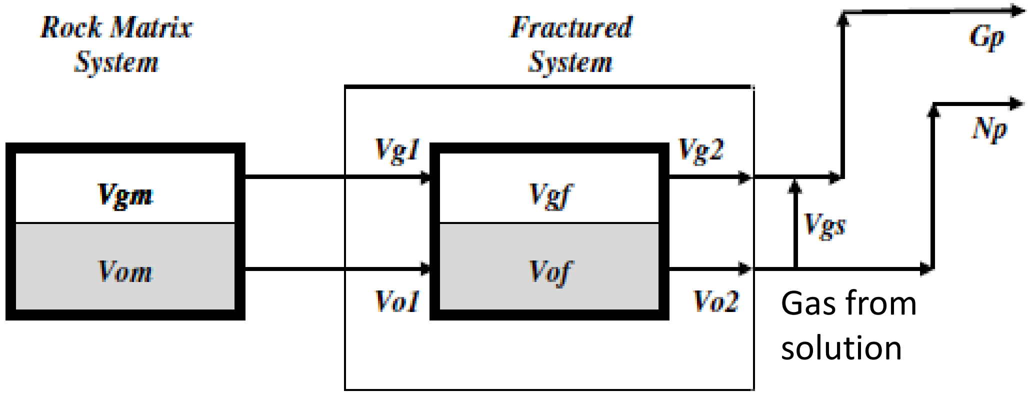


Fig. A-1 Volumetric material balance in the fractured system.

From Penuela et al. SPE 68831

$$V_{ofi} + V_{gfi} = V_{of2} + V_{gf2} + V_{o1} + V_{g1} - V_{o2} - V_{g2} + \Delta V_{fw} + \Delta V_{f}$$

Initial oil + gas in fractures = Later oil + gas in fractures + oil + gas from matrix - oil + gas produced + Expansion of fracture connate water + Expansion of fracture pore volume

Or gas-cap expansion

Or aquifer influx

Rearrange terms to give linear equation in oil-in-place in matrix and in fractures

- Errors can be large
- Non-uniform pressures (esp. poor communication between matrix & fractures)
- Reservoir pressure ~ bubble point and gas comes out of solution

Dual porosity simulation model

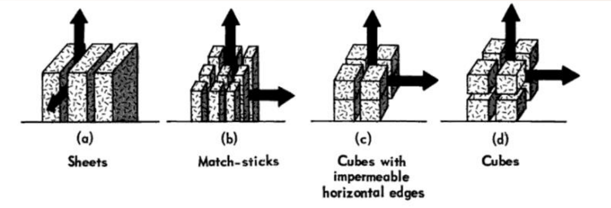
Transfer function for flow from matrix into fractures

Direct flow between matrix blocks => dual permeability model

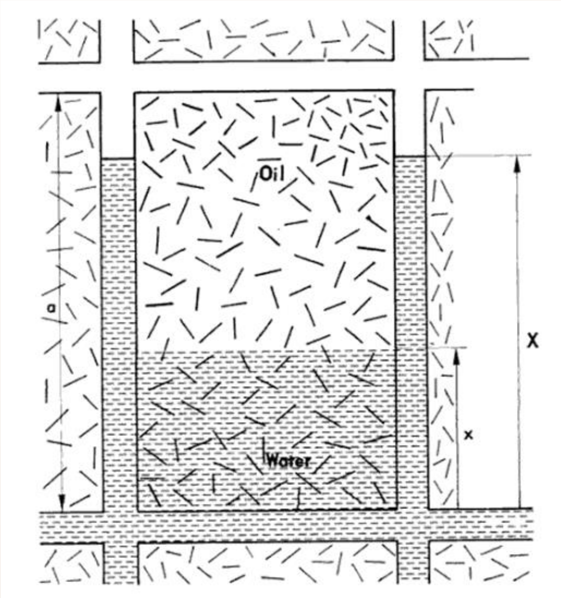
$$\tau = \sigma \frac{k_m k_r}{\mu}\{(p_m - pf) + \text{Gravity forces} + \text{Capillary forces} + \text{pore, fracture, fluid vol. expansions}\}$$

Viscous forces (Sudation)

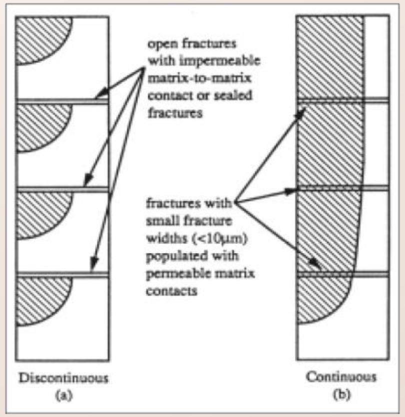
σ is the shape factor, $4n(n+2)/L^2$
n is the number of flow dimensions
L is characteristic dimension of matrix block
k_m is the matrix permeability
k_r is the relative permeability
μ is the fluid viscosity
p_m is the average matrix pressure
p_f is the fracture pressure



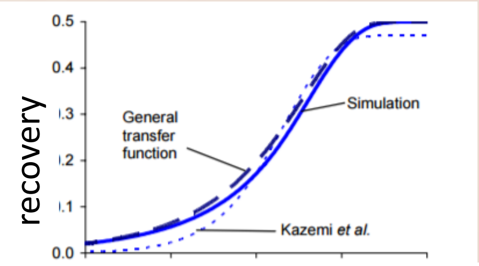
- Distribution of shape factor values
- Time-varying shape factors



Co-current vs counter-current?

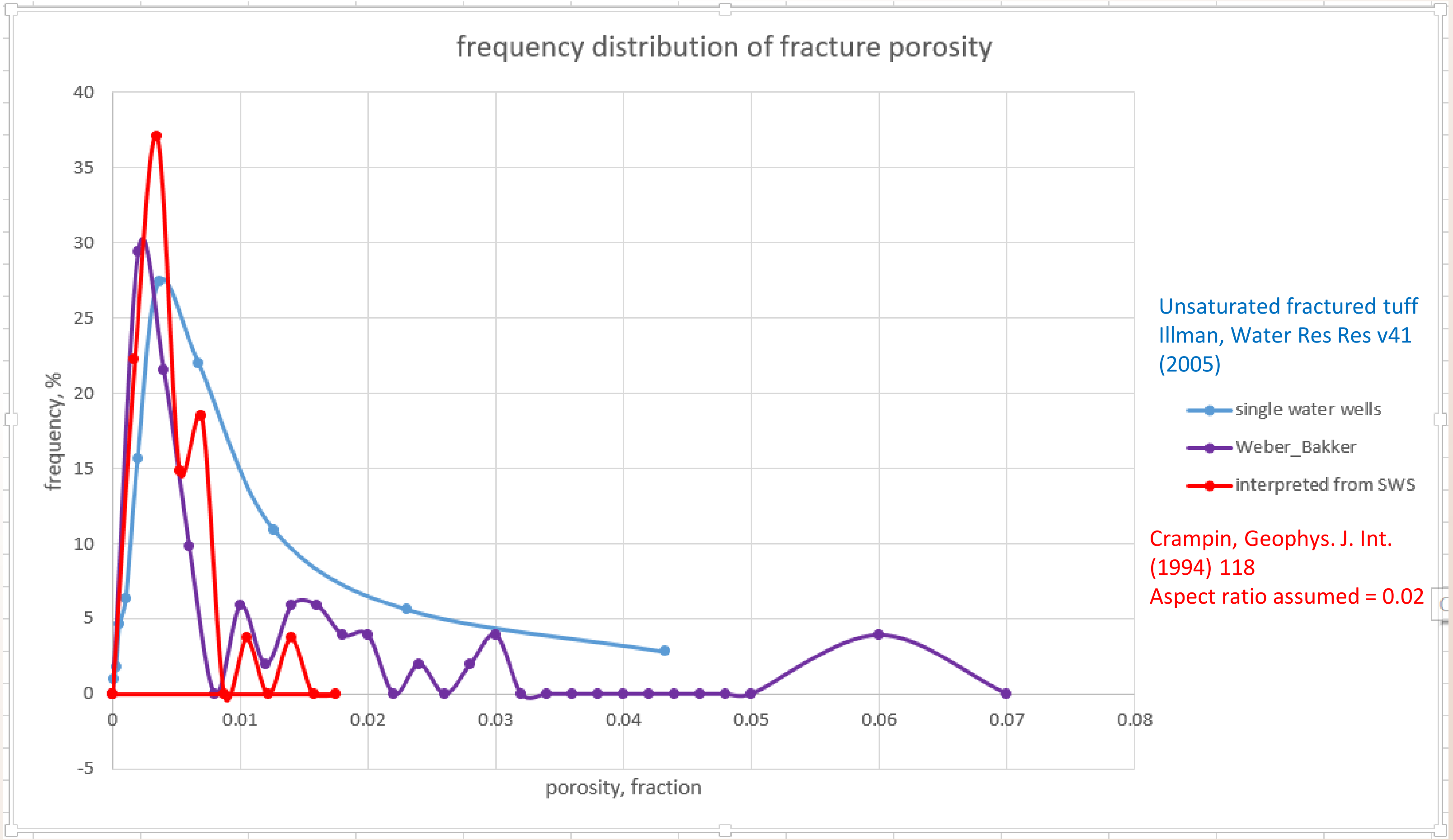


Capillary continuity?



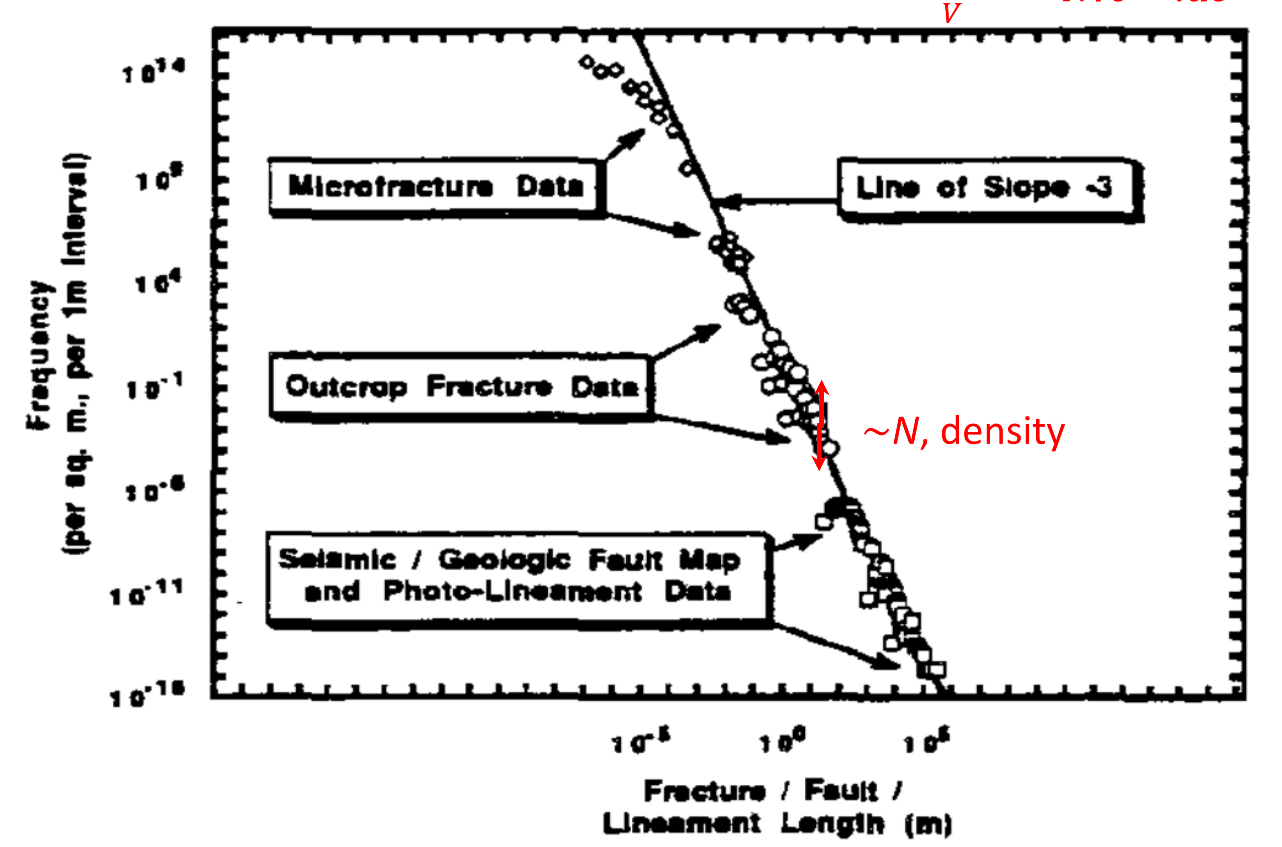
Cumulative volume injected

Frequency distribution of fracture porosity

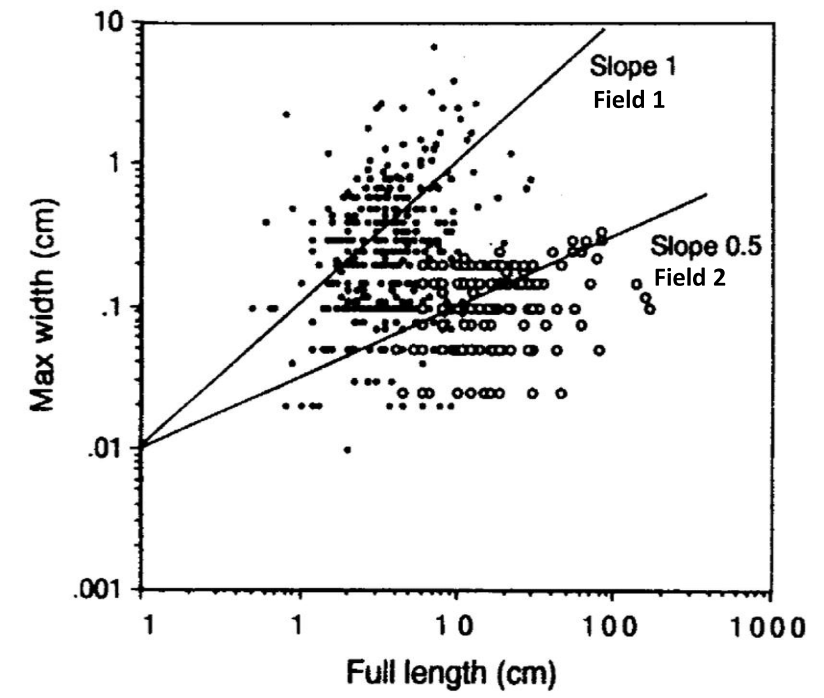


Fracture lengths and apertures

For a volume: $\frac{n(c).dc}{V} = N.c^{-4}.dc$



Max. fracture aperture vs length
From core data in 2 separate fields
Heffer & Koutsabeloulis, 1993



Permeability increases with scale of measurement
and so does porosity

Crystalline rocks

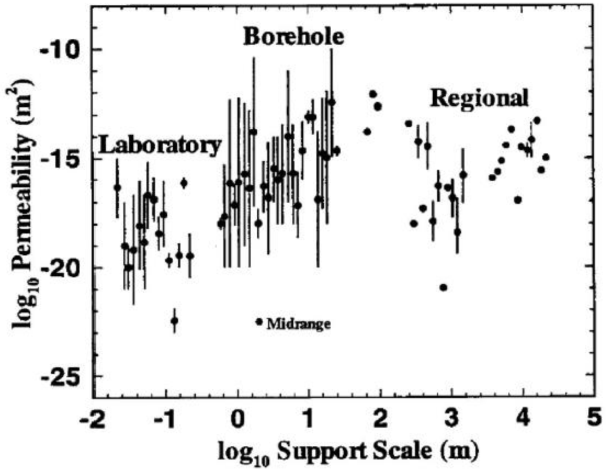


Figure 9. Permeability of crystalline rocks as a function of experimental scale. After *Clauser* [1992], adapted by *Neuman* [1994].

'Double porosity' limestone/dolomite

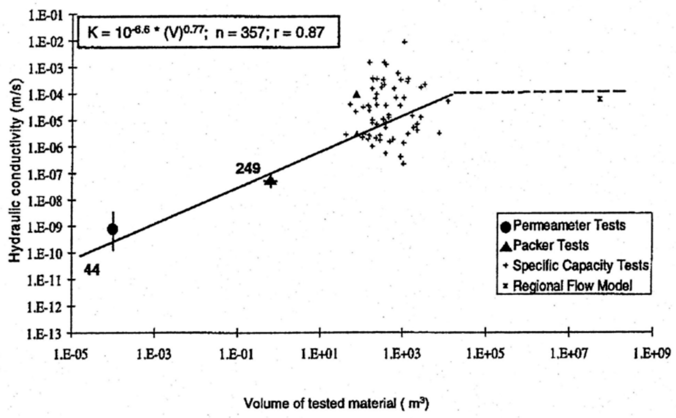
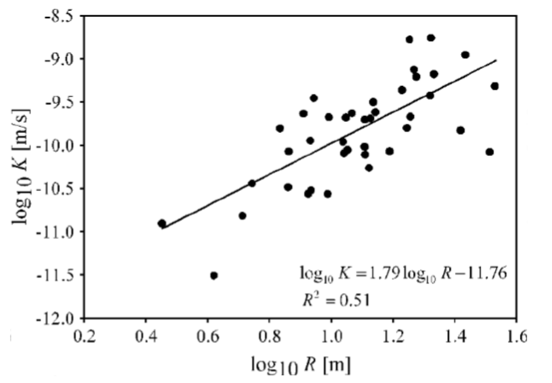
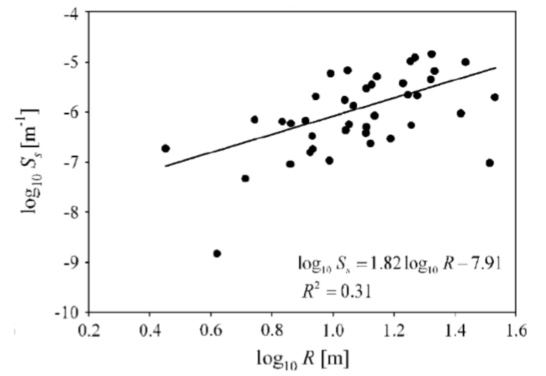


Figure 11. Hydraulic conductivity versus inferred support volume in "double-porosity" limestone-dominated Sinnipee Group of northeastern Illinois and southern Wisconsin. After *Schulze-Makuch et al.* [1999]. Reprinted from *Ground Water* with permission of the National Ground Water Association. Copyright 1999.

Fractured granite





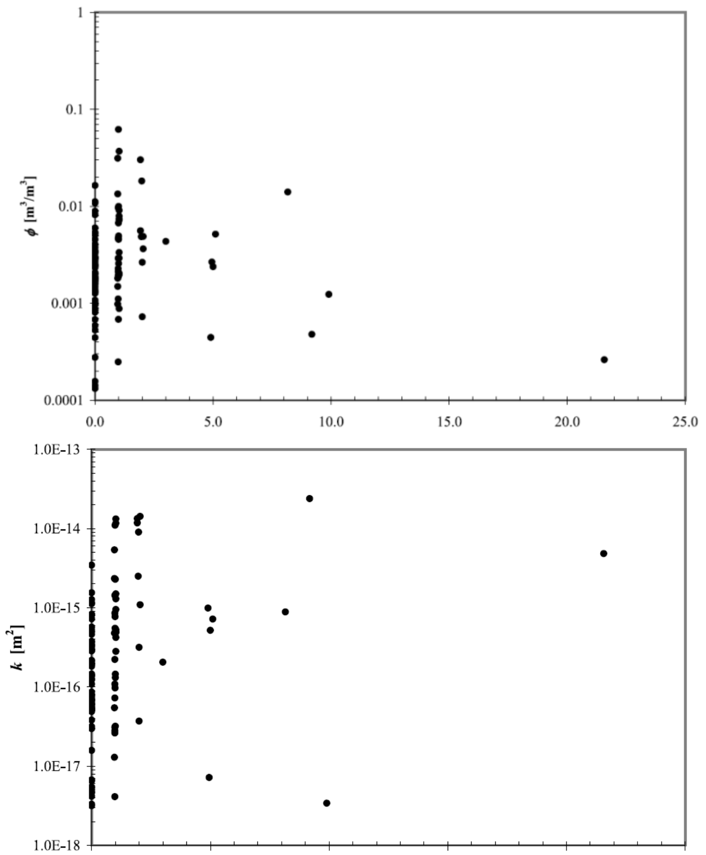
Cross-hole hydraulic tests
Illman & Tartakovsky, Ground Water 2006 v44(4)

Well-test poroperms in fractured reservoirs are weakly related to fracture densities in wells

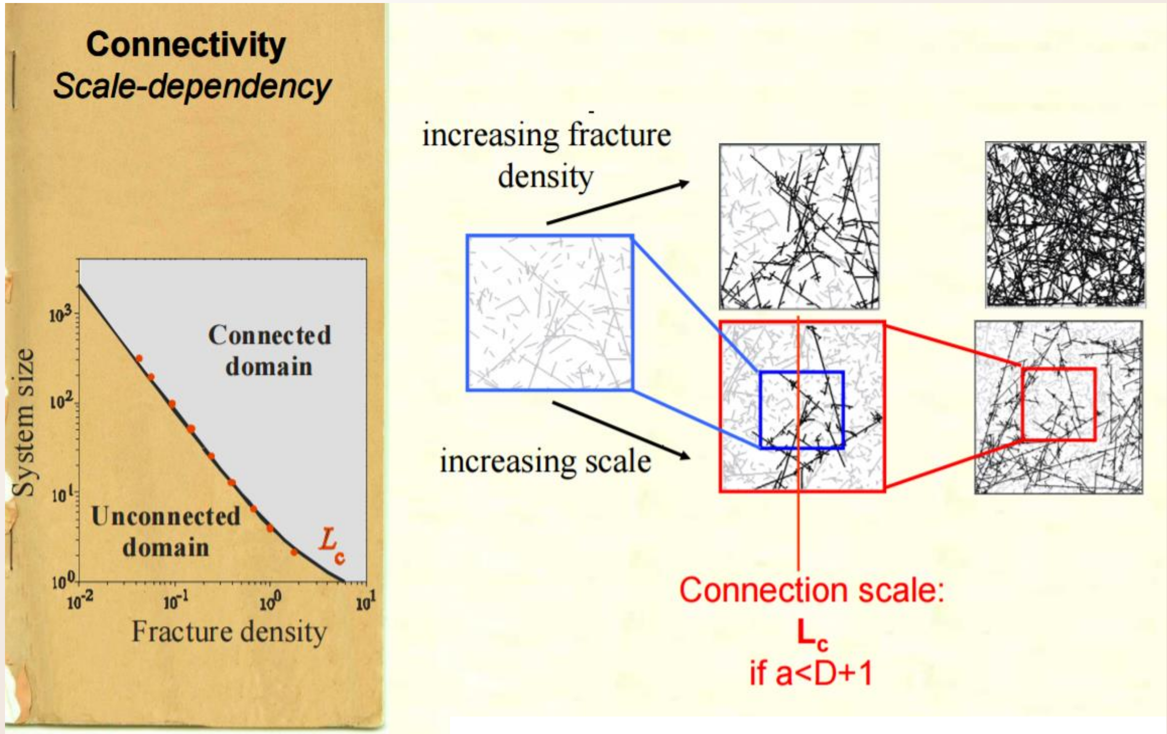
Illman, 2005, WATER RESOURCES RESEARCH, VOL. 41

Porosity from test

Perm'y from test



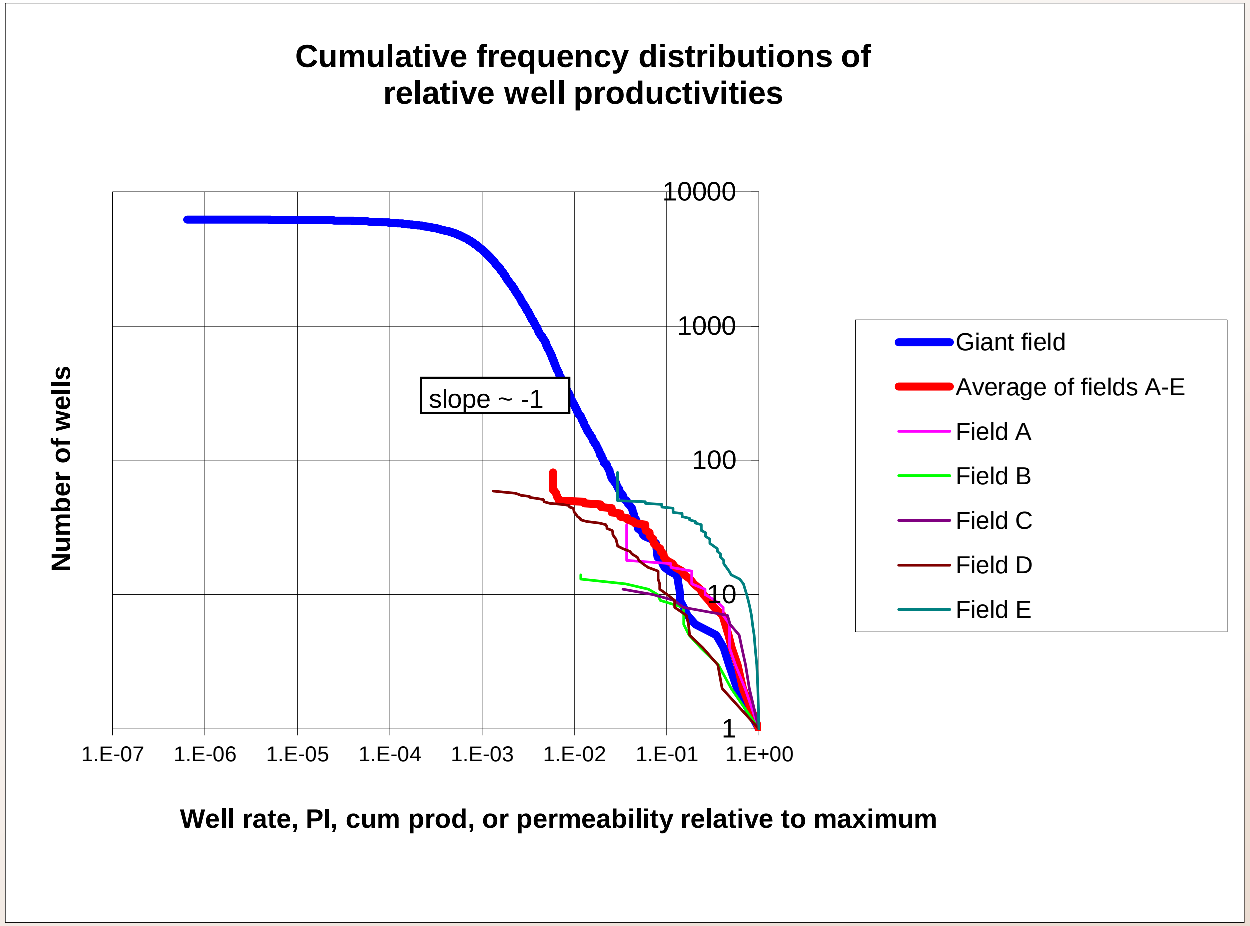
Fracture density from BHTV (counts/m)



$$n(l,L)dl = \alpha L^D l^{-a} dl \qquad \text{for } l \in [l_{min}, l_{max}].$$

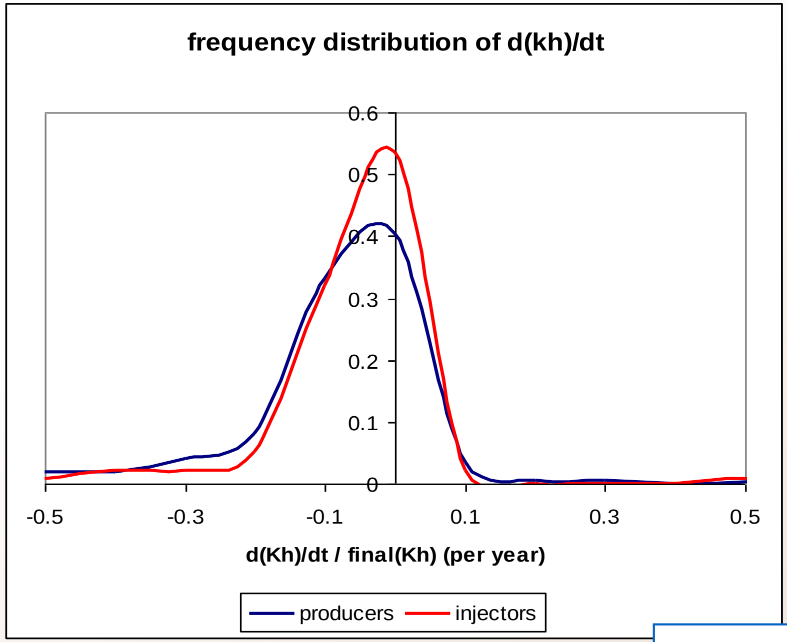
Fracture connectivity is complex!

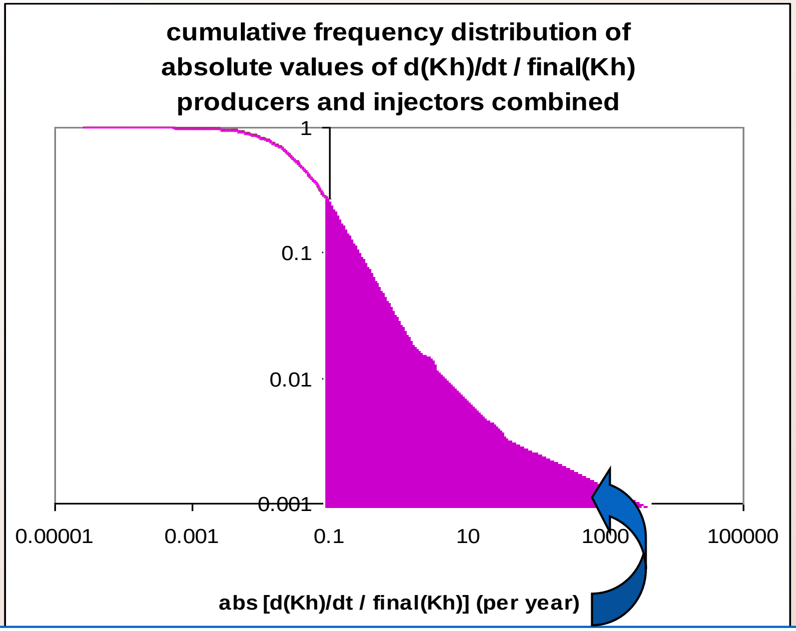
Fractured reservoirs contain only a few very productive wells



Time-dependent well-test permeabilities

(large carbonate field)





Of the wells with multiple tests, 20% showed rates of change of Kh more than 10% per annum

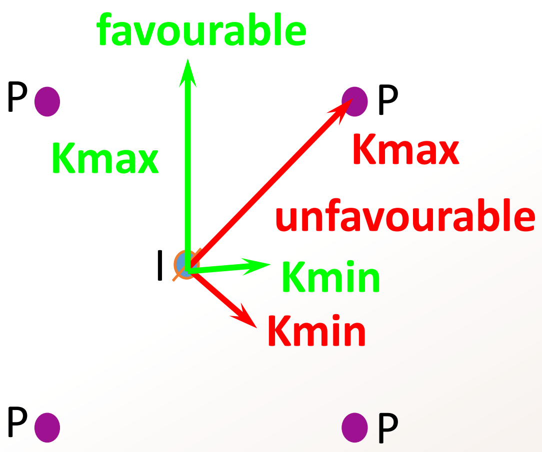
Field Directionality is a vital influence on recovery.

Areal sweep efficiency and anisotropic permeability

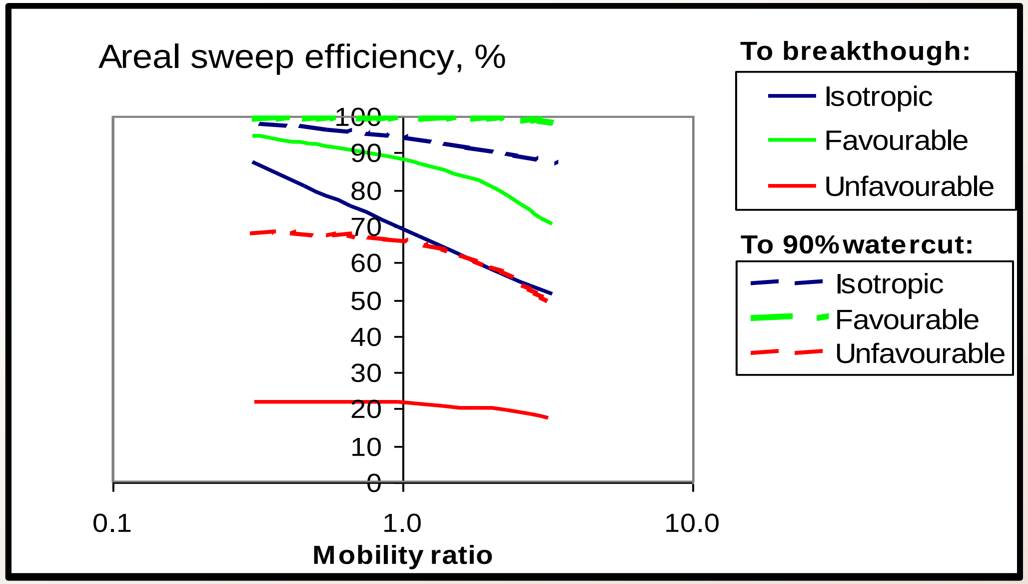
(classic: Caudle 1959)

For a 5 spot pattern of wells:

Permeability axes

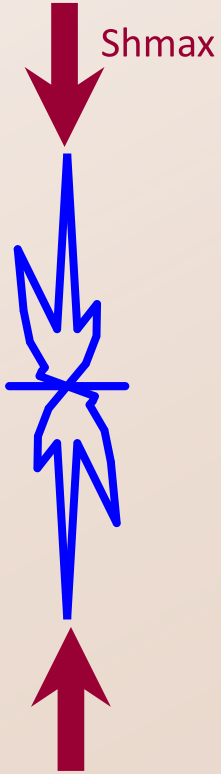


Physical model with Kmax/Kmin = 16



Flooding directionalities are strongly related to stress state

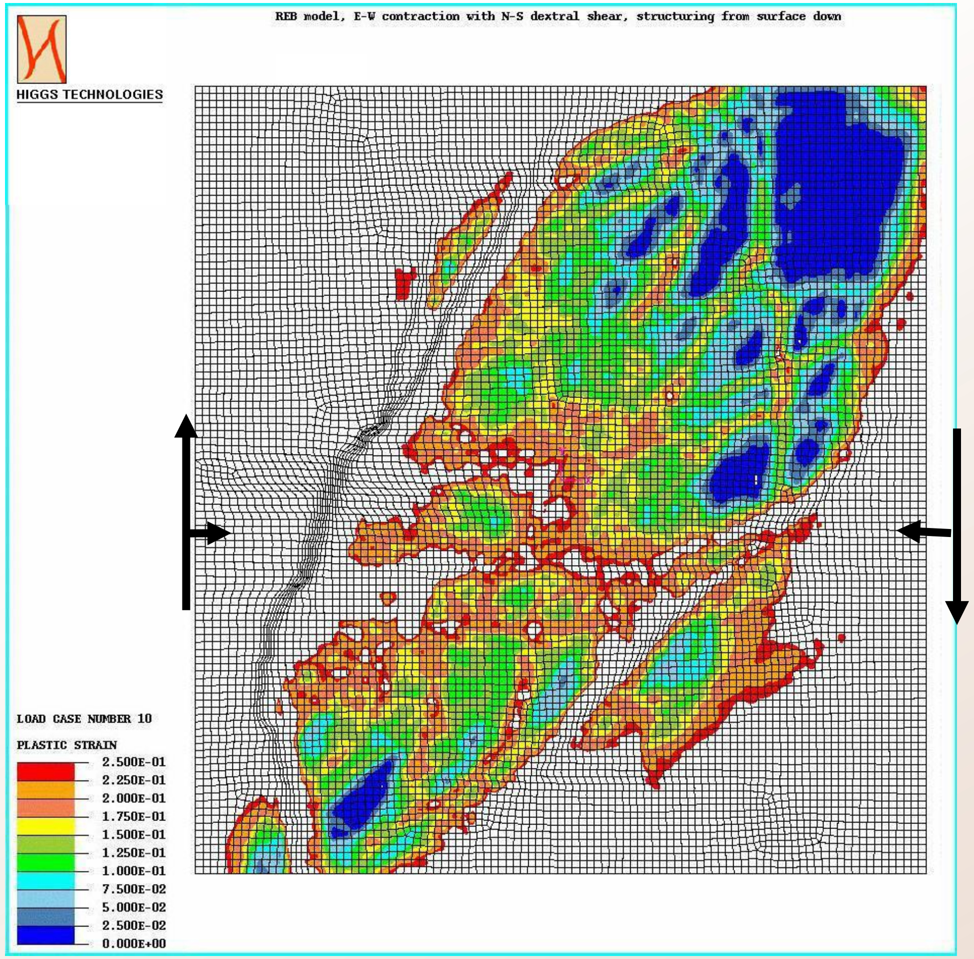
'Fractured' Reservoirs (33 cases)



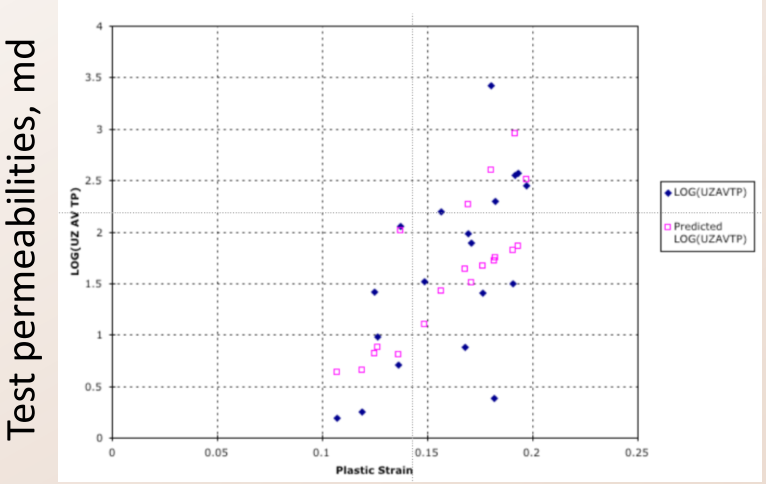
Orientation (+/- 45^o) of well pattern relative to permeability axes can change recoveries by 10's of % points

Strain modelling for fracture spatial distribution

from palinspastic reconstruction of structure followed by FE forward modelling of structural history -> inelastic strains



Combination of structural & depletion effects – predicted permeability vs actual r^2~ 0.6



Plastic strain

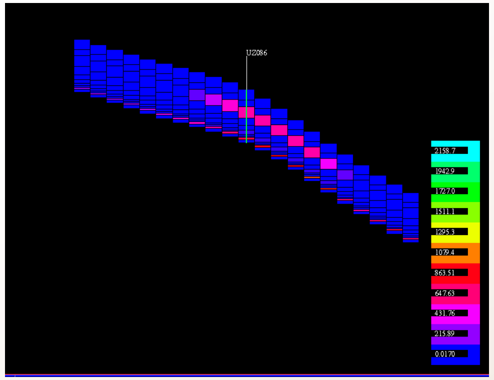
Time-dependent fracture permeability

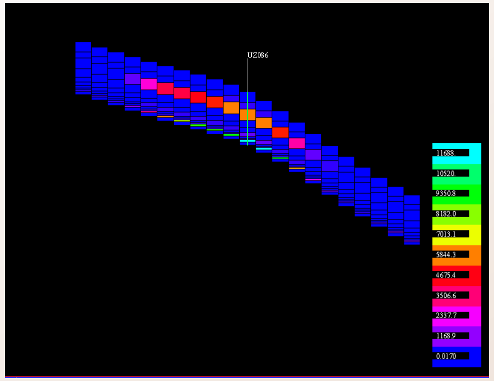
Exacerbation of thief layer (higher density fracturing) by cooling & pressurisation – coupled geomechanical-flow modelling

Permeabilities across cross-section

Layered carbonate reservoir

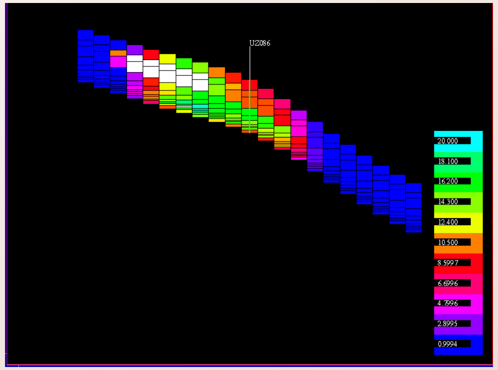
initial





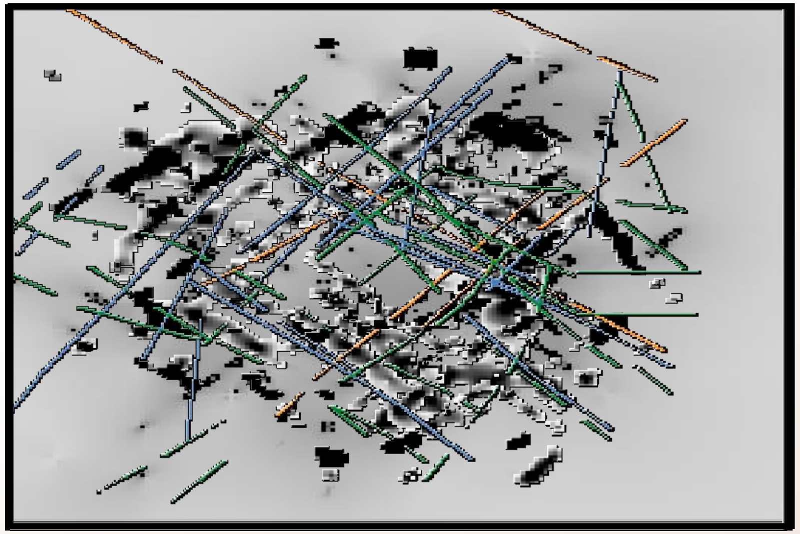
Final, after significant time of cool water injection

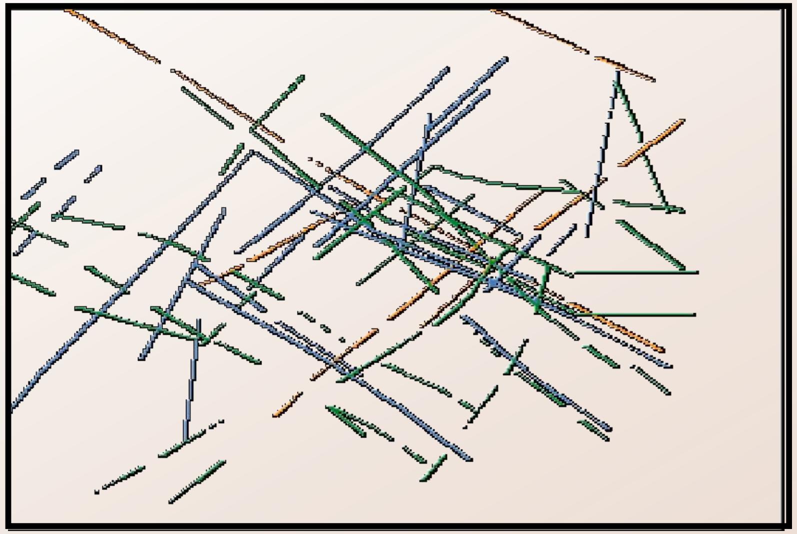
Ratio, final/initial



Well flowrate fluctuation correlations follow structural trends

Composite of all 4 principal components



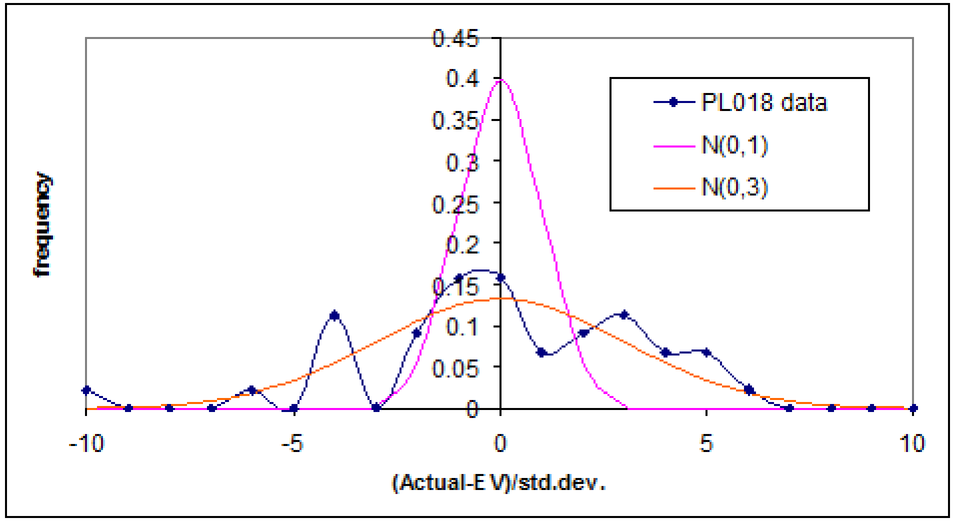


Structural lineaments
Porosity trends
Core fracture density trends

Scientific test of a model is whether it can skilfully predict new data

Probabilistic forecasts vs reality

Comparison between probabilistic forecast of production[1] and subsequent actual production[2] from 4 fractured chalk/sst fields in a Norwegian production licence



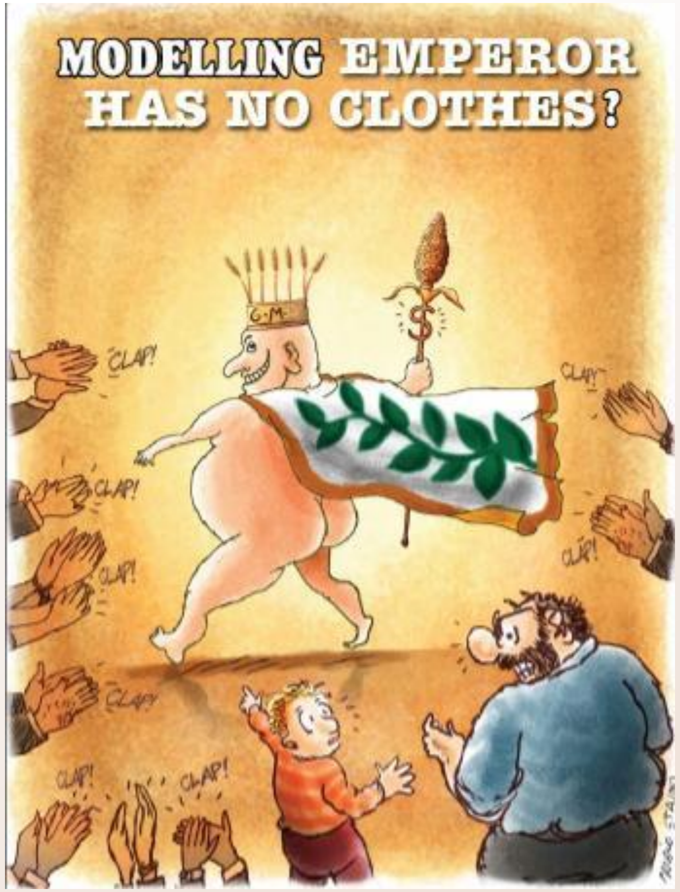
The distribution of normalised errors* in prediction is much wider than the forecast uncertainties. The standard deviation of errors appears to be ~3 x predicted standard deviation.

[1]published by Jensen, T.B. in SPE 49091, 1998

[2]published by Norwegian Petroleum Directorate on website: http://factpages.npd.no/factpages/

* each difference normalised by prediction standard deviation, which was estimated from forecasts as (P90-P10)/2.56.

The Naked Truth?



“All models are wrong; some are useful” *George Box*