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The Challenge of Estimating Recovery from Naturally Fractured Reservoirs

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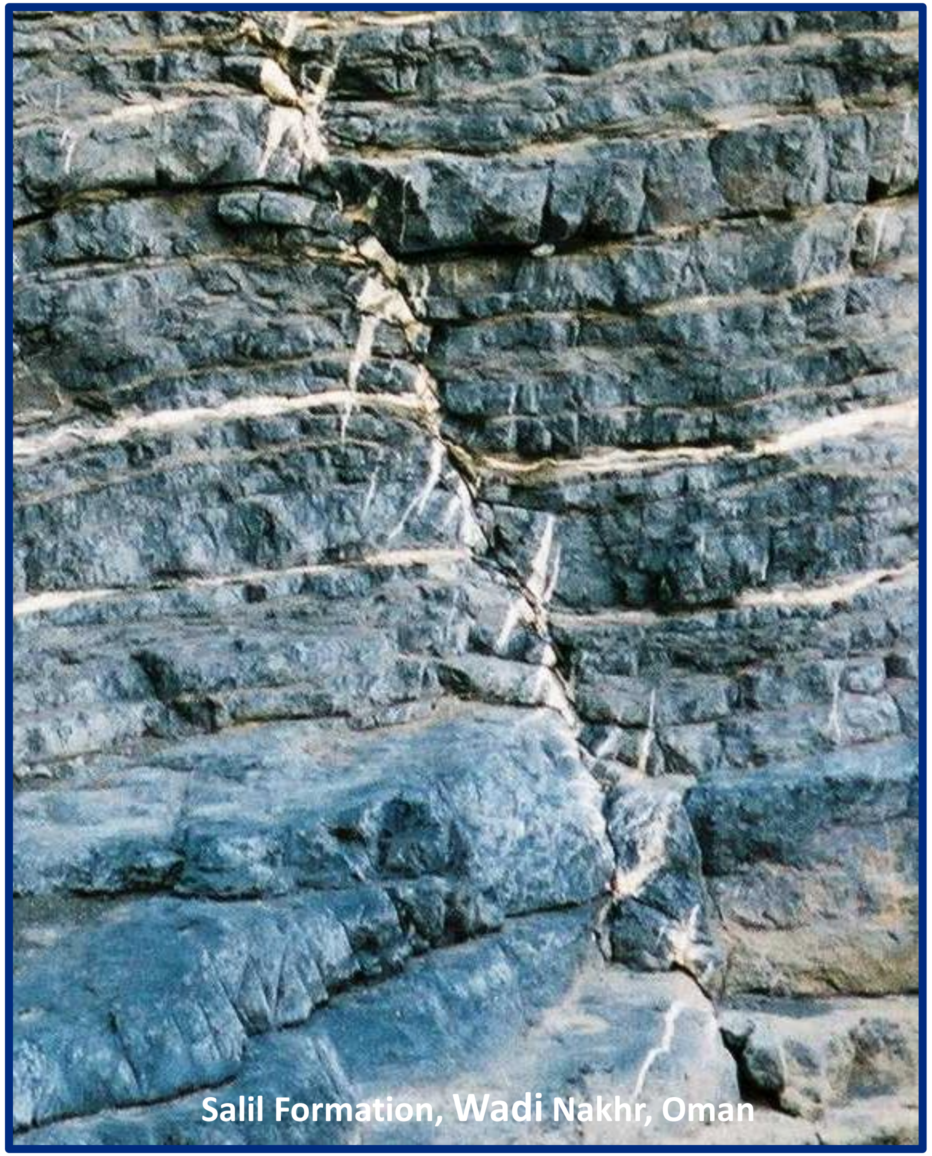
- Our toolkit
- Reservoir engineering principles- an example
- Fracture porosity and permeability
- Conclusions

Recovery Factors: what do they really mean?

What is important in fractured reservoirs?

- 20% of the world's reserves are estimated to be in fractured reservoirs[(1)]
- What is a fractured reservoir?
  - Finding fractures is not enough
  - For our purposes, a fractured reservoir might be defined as…

*"a reservoir in which naturally occurring fractures either have, or are predicted to have, a significant effect on reservoir **fluid flow** either in the form of increased reservoir permeability and/or porosity or increased permeability anisotropy"* [(2)]


Salil Formation, Wadi Nakhr, Oman

(1) Firoozabadi, A., 2000.
(2) Nelson, R.A., 1985.

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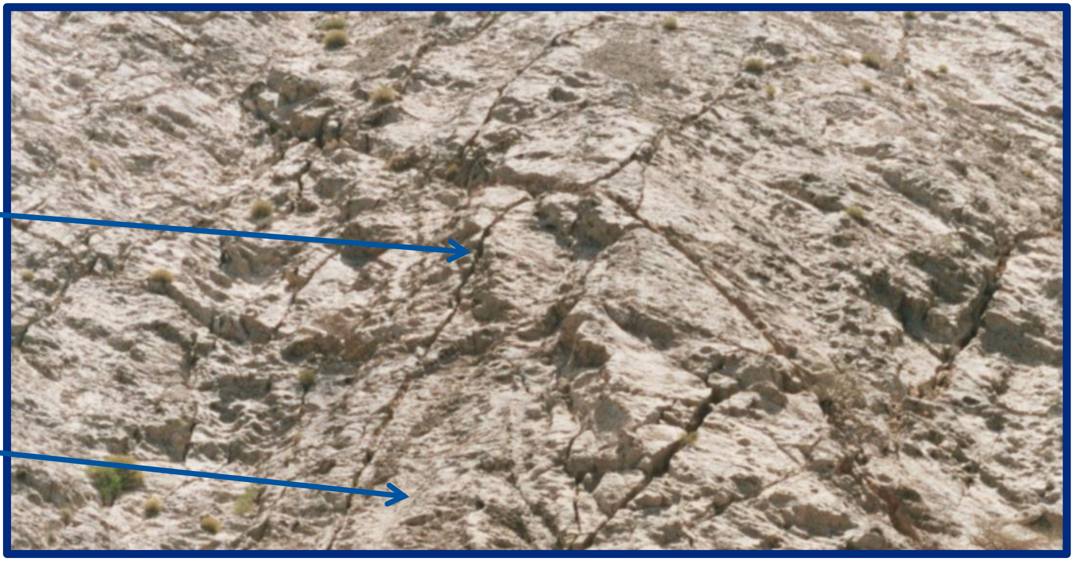
The volumetric equation

'Traditional' dual porosity model of two interacting systems:

- Fracture network
  - Low storativity,
  - High conductivity
- Rock matrix
  - High storativity
  - No (or little) connectivity



'Static' data

'Dynamic' part influenced by many factors

Double up for fractured reservoirs

$$UR = \underbrace{\frac{GRV \times NTG \times \emptyset \times (1 - S_w)}{B_{o,g}}}_{\text{'Static' data}} \times \underbrace{RF}_{\text{'Dynamic' part}}$$

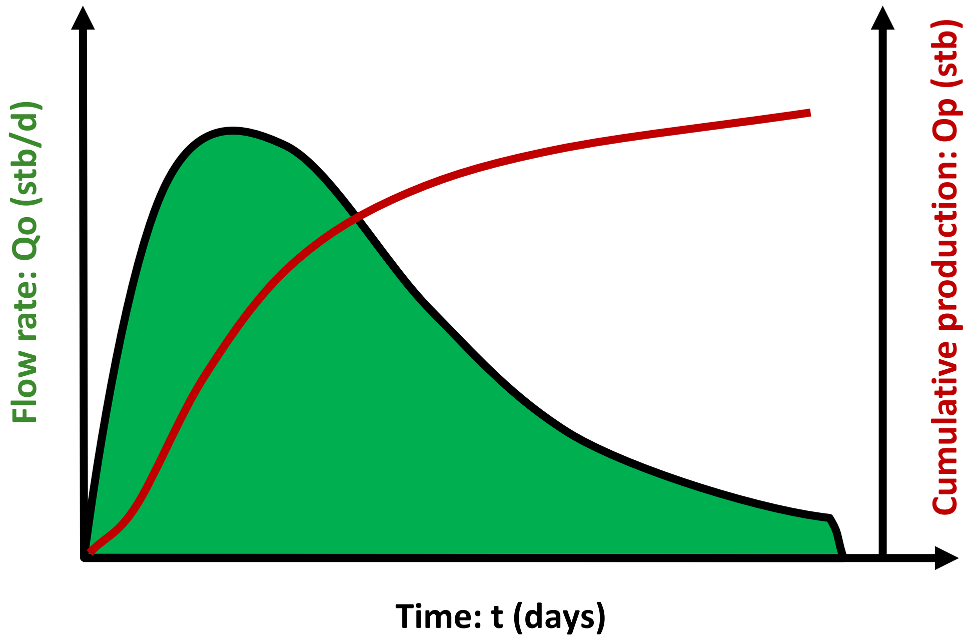
Recovery factors and production forecasts are intrinsically linked

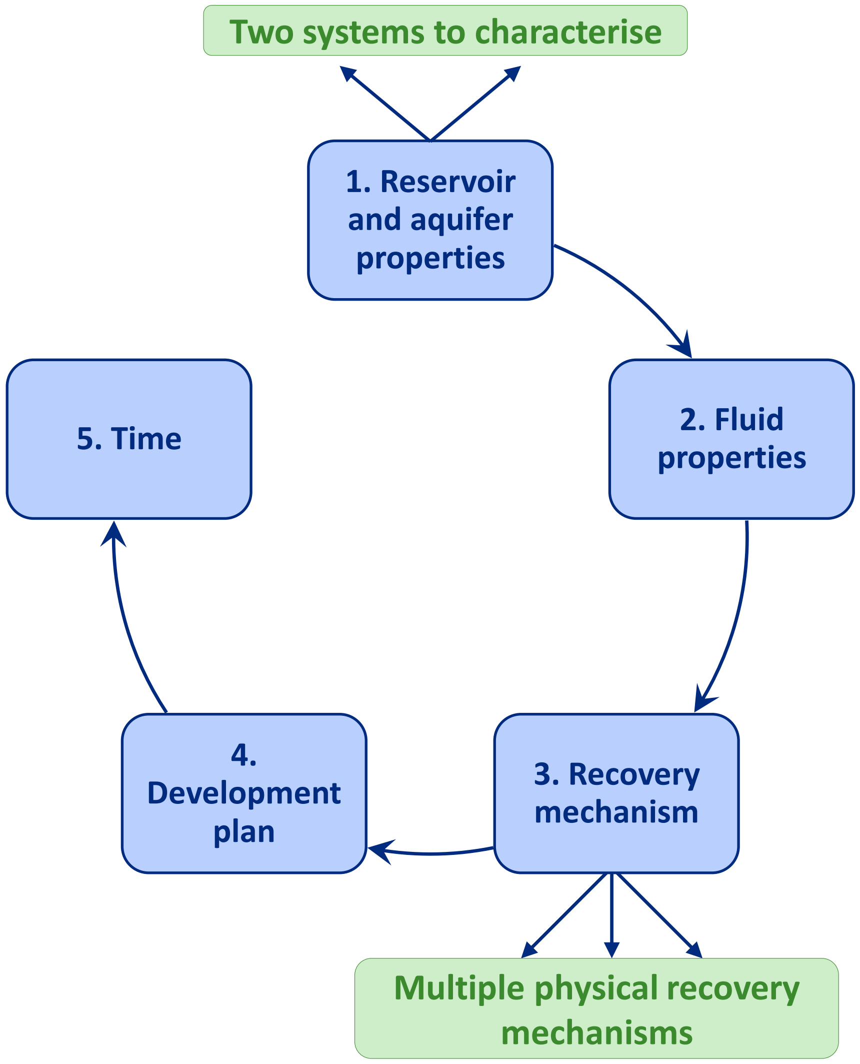
Parameters often interdependent:
e.g. matrix NTG cut-off and matrix RF might be dependent on fracture porosity.

Recovery factors

"Recovery is the time integral of a production profile over the life of the field."

$$RF(T) = \frac{O_p}{STOIIP} = \frac{\int_0^T q_o(t)dt}{STOIIP}$$



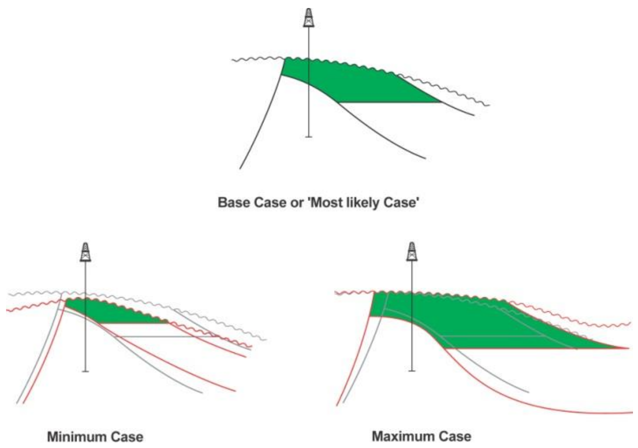


There are five elements that go into the construction of a production profile, all of which affect RFs

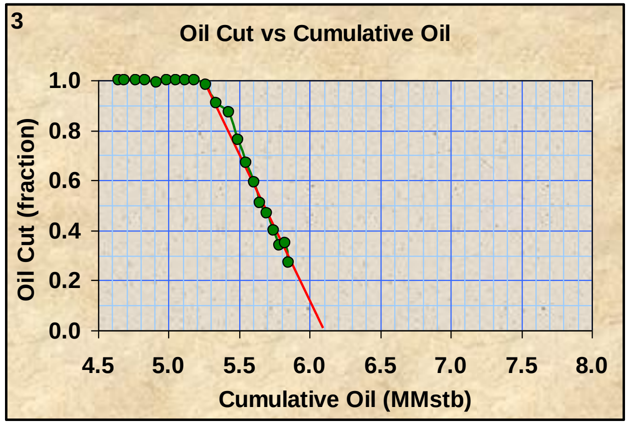
Our toolkit

Our recovery factor toolkit

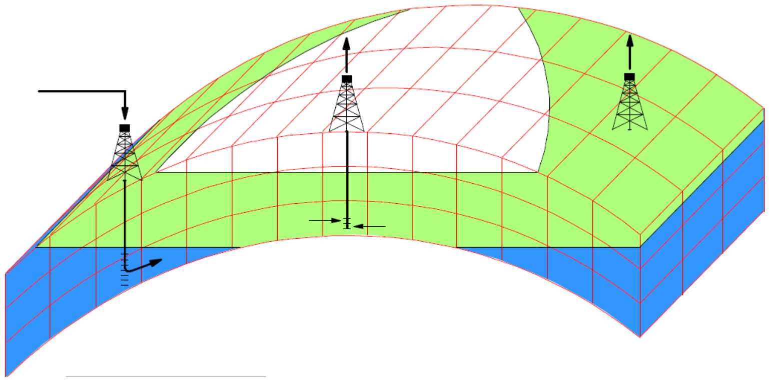
Analogues



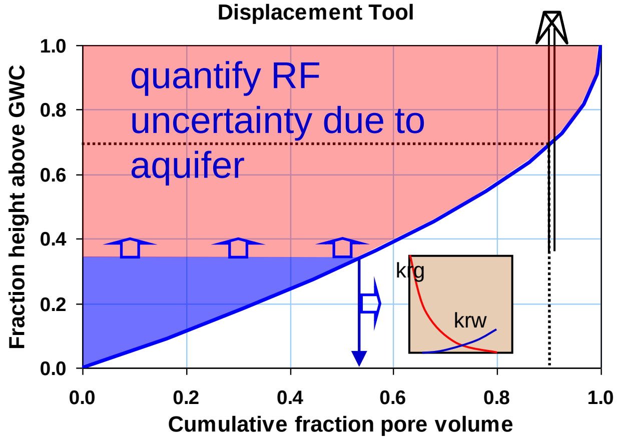
Decline curve analysis



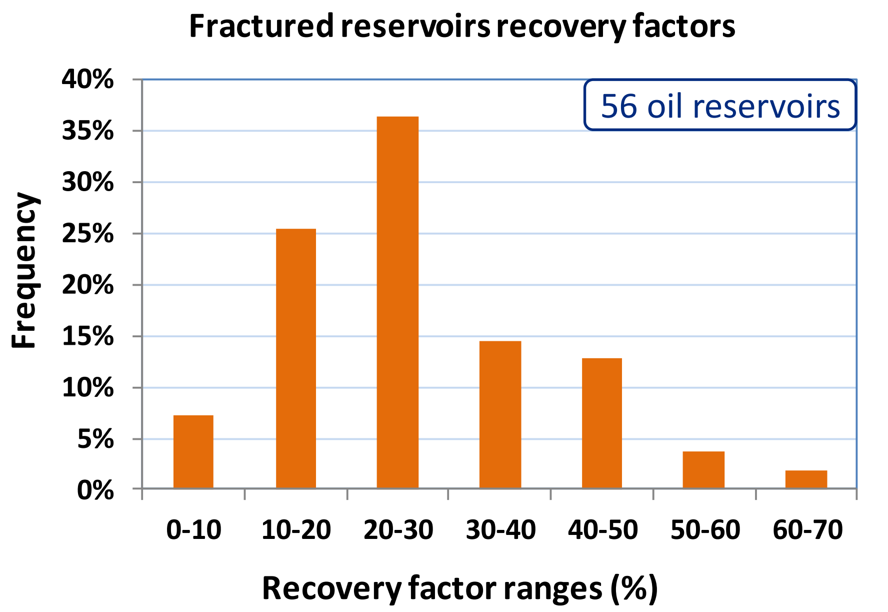
Numerical simulation

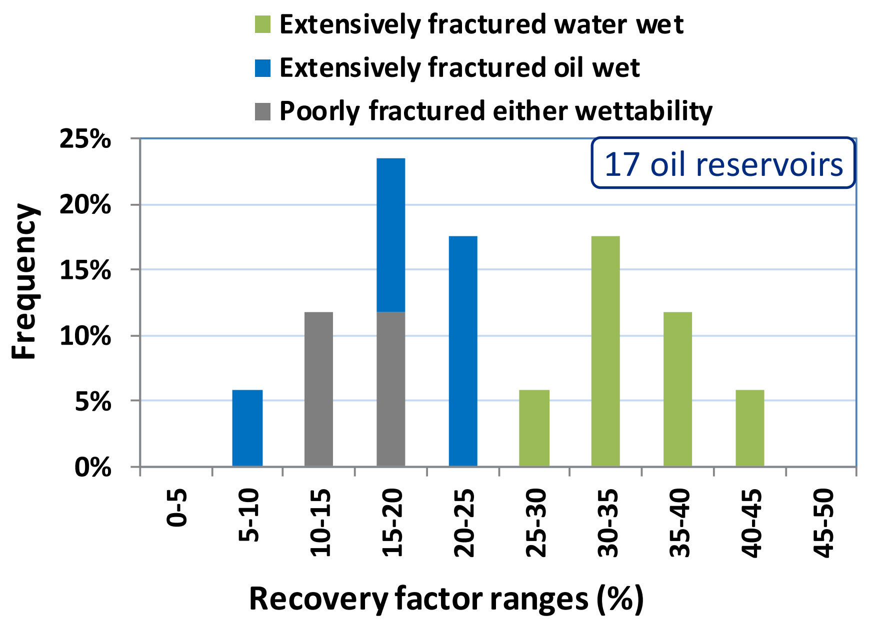


Analytical methods



Our toolkit: Analogues

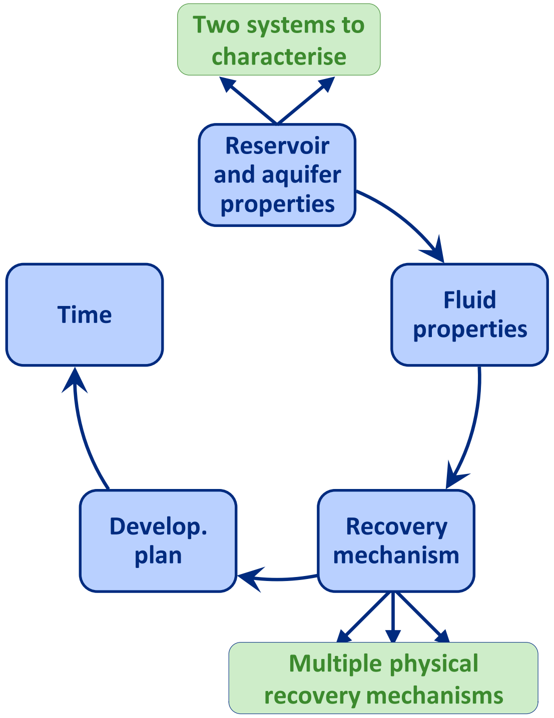




Limited published data:

- Allan, J. and Qing Sun (2003)
- Anguilera, R. (1999, 2011)

Selecting an analogue



Finding a suitable analogue for a fractured reservoir is problematic. Instead, we should look for analogues for the building blocks (e.g. fracture porosity, recovery mechanism)

Our toolkit: Decline Curve Analysis

- Conventional (Arps type) equation sometimes does not work well for fractured reservoirs:
  - High initial rates
  - Rapid decline in rates at some stage
  - Long tail end

$$q_t = \frac{q_i}{(1 + b \cdot d_i)^{\frac{1}{b}}}$$

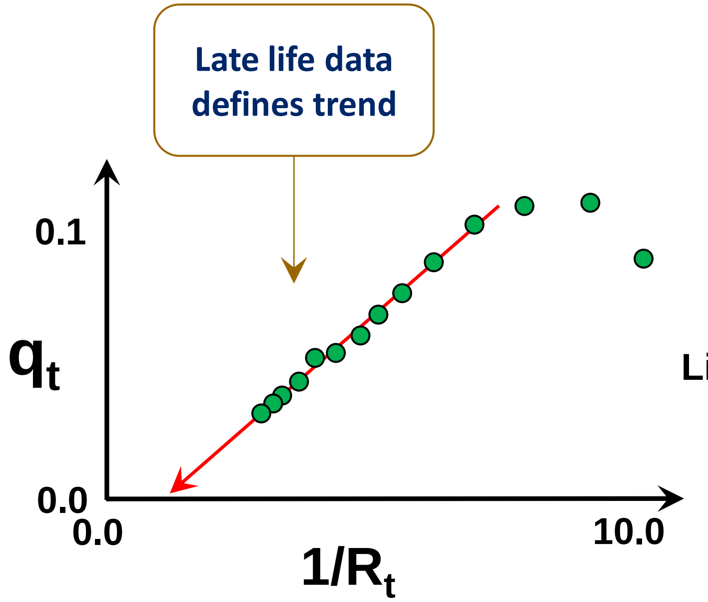
- In fractured reservoirs, this might work:

$$q_t = a_0 \frac{1}{R_t} - b_0$$

$R_t = oil\ recovery\ at\ time\ t$

$a_0 = capillary\ pressure\ term$

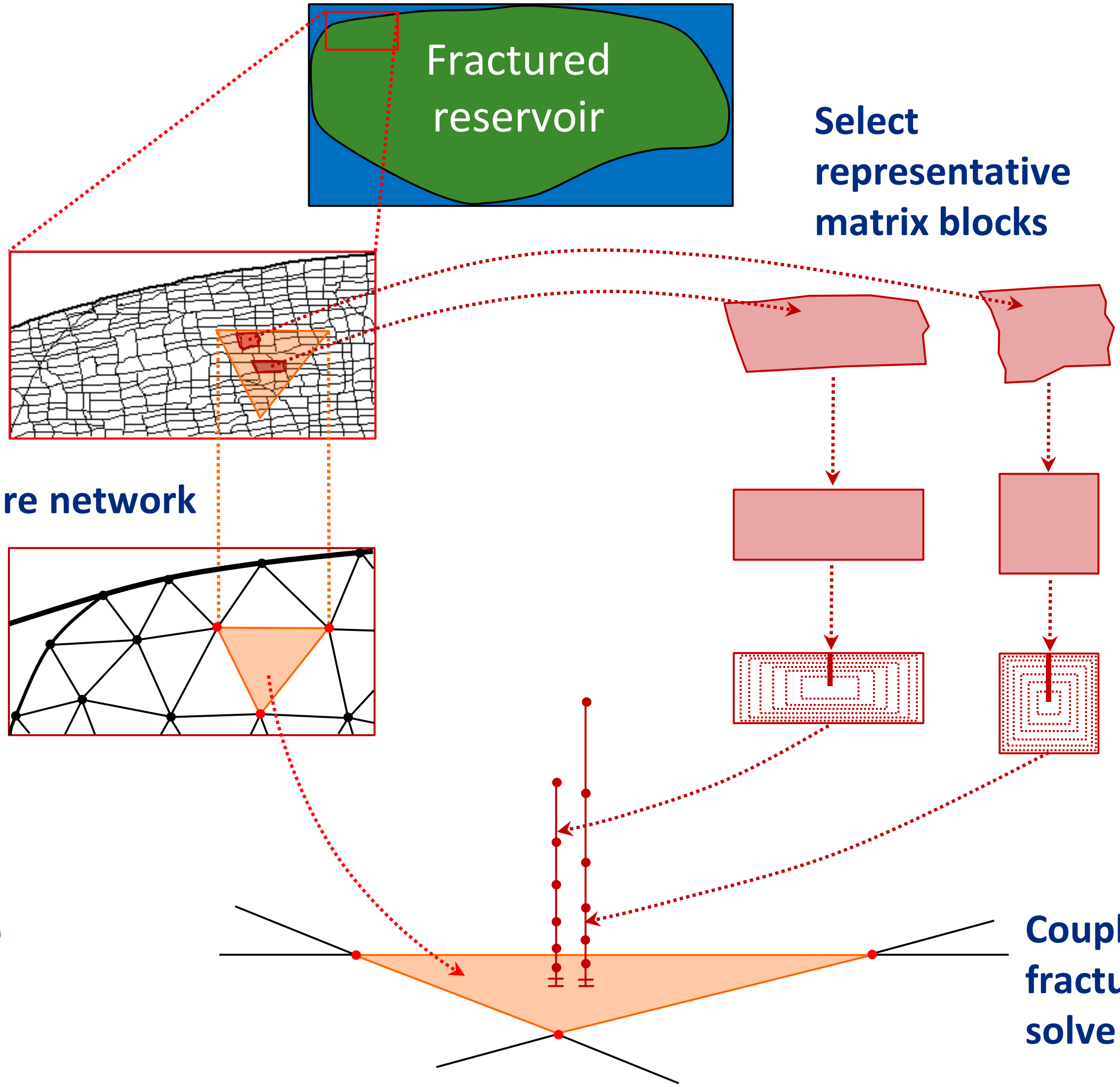
$b_0 = gravity\ term$



Li, K. and Horne, R. N., SPE 83470

DCA applicable in mature fields but not in the early life when investment decisions are being made

Our toolkit: Numerical simulation



Characterisation of fractures

Upscale fracture network

Create fracture network mesh (grid)

Select representative matrix blocks

Idealise matrix blocks

Model matrix blocks (properties)

Couple matrix models and fracture network grid and solve numerically

An example of one possible modeling approach

How useful is numerical simulation?

Simulation comes into its own when you have production data and can calibrate through history matching.

Simulation has limited use in the pre-development stage for all types of reservoirs, but particularly for fractured reservoirs because:

- Recovery is determined by physics and chemistry and the simulator cannot tell you what that is.
- Fractured reservoirs have many more physical processes than single porosity reservoirs and therefore many more degrees of freedom.
- You need to work out the physical recovery mechanism and ‘instruct’ the simulator, often by calibrating against analytical calculations.

Simulation is useful for combining all the components and generating production profiles, for testing hypotheses and development concepts.

The application of reservoir engineering principles: An example

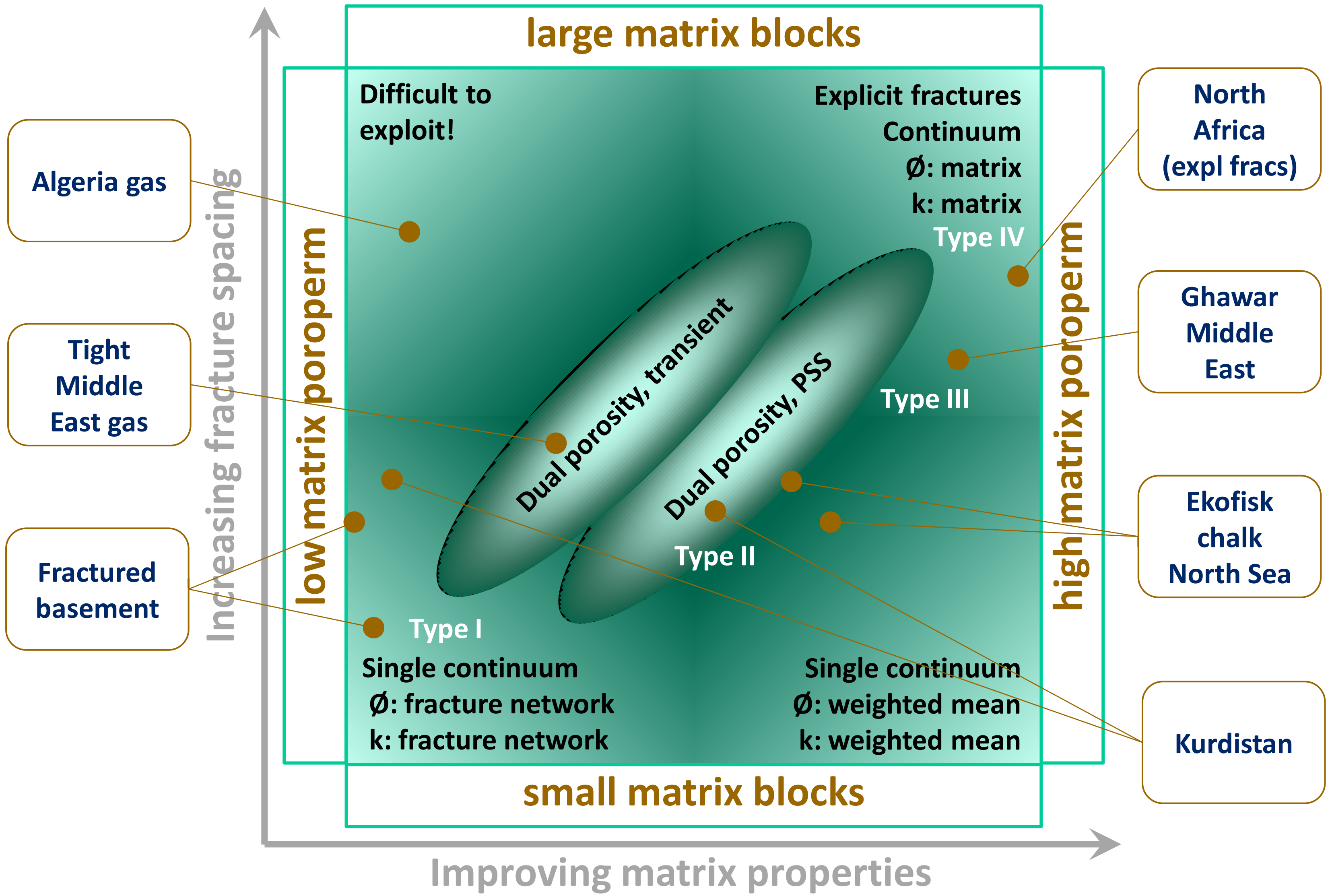
Quote by Roberto Aguilera:

Ranges of Recovery

Each naturally fractured reservoir should be considered as a research project by itself. As such it has to be studied carefully to estimate recoveries.

Understand the type of reservoir

Qualitative 2D space of matrix poroperm and fracture spacing



Nelson classification 1999

Type I
fractures porosity
fracture permeability

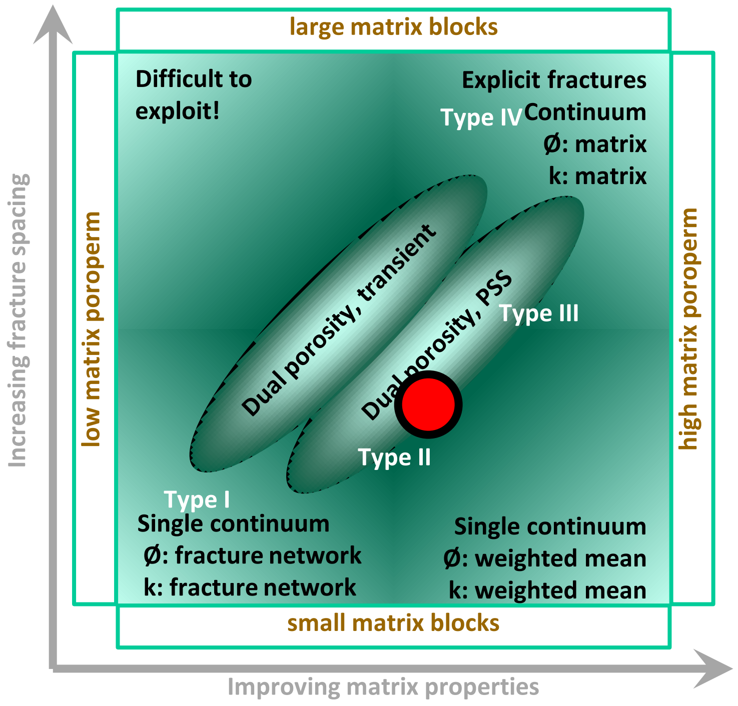
Type II
matrix porosity
fracture permeability

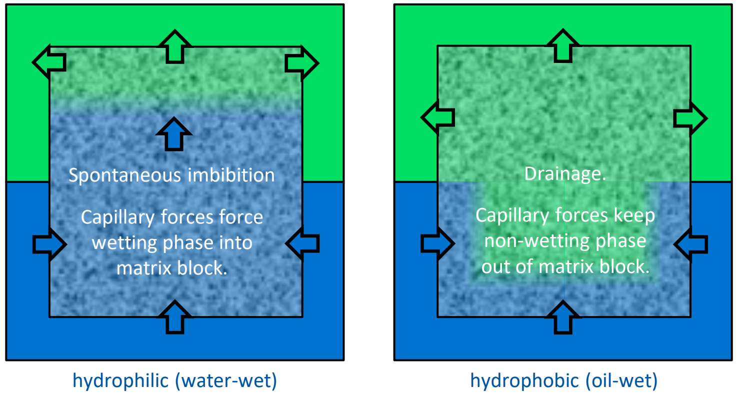
Type III
matrix porosity
matrix permeability
fracture enhanced perm.

Type IV
matrix porosity
matrix permeability
fracture anisotropy

This helps in the search for analogues

Oil field with strong aquifer: depleted





We have no (real) control over wettability. Hydrophobic (oil wet) RF can be VERY low. Greater matrix height means more gravity and possibly better recovery

- Thick carbonate
  - Fractured limestone
  - 50 m karst at crest
- Matrix
  - Porosity: 15%
  - Permeability: 20 mD
- Fractured on 2 metre scale
  - Very high permeability
  - Significant storage

Dual porosity PSS behavior

- Other information
  - Light, undersaturated oil
  - 200 m column, strong aquifer
- Recovery factor range
  - Fractures and vugs: 50 to 80% - gravity stable aquifer
  - Matrix: 5% to 10% - relies on imbibition
- Critical data
  - Production data shows rising OWC
  - SCAL data shows some propensity for spontaneous imbibition
  - Matrix block shape and size

Fracture porosity and permeability

The problem of permeability

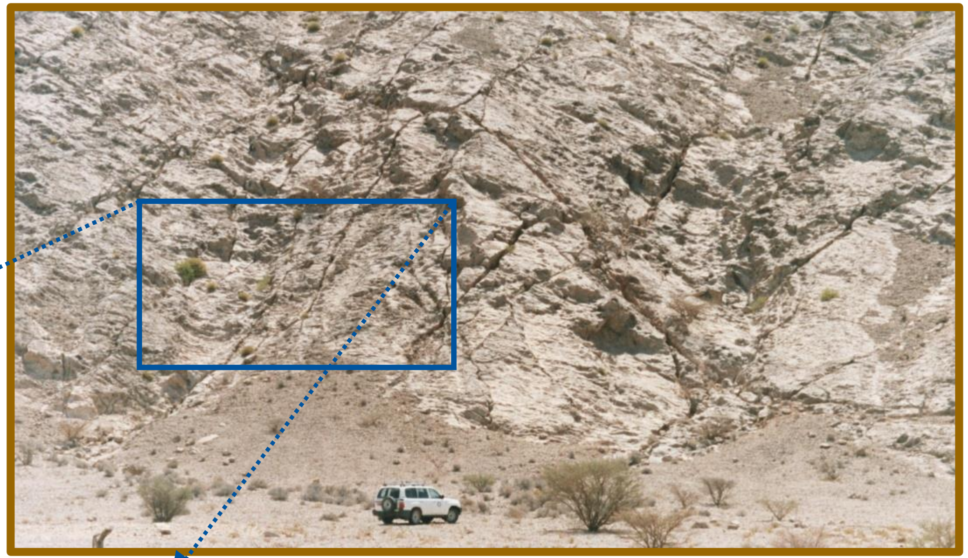
$$\boldsymbol{u} = -\frac{\boldsymbol{k}}{\mu}\nabla P$$

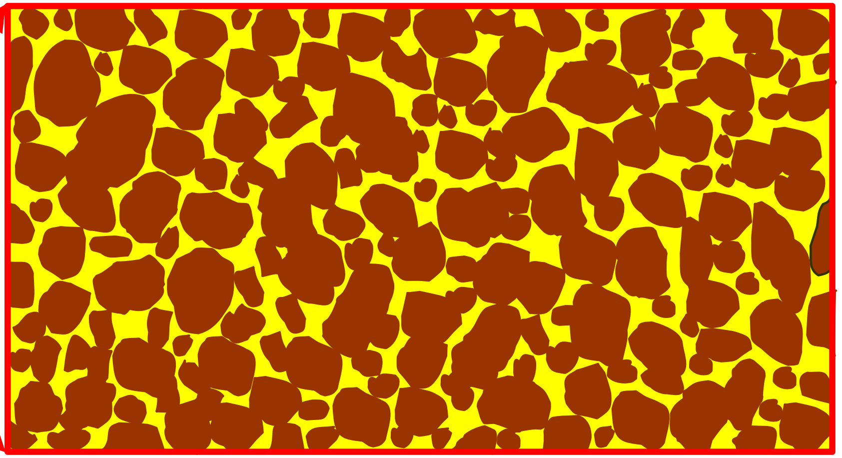
$\boldsymbol{u} = fluid\ velocity$

$\boldsymbol{k} = permeability$

$\mu = viscosity$

$P = pressure$





The use of Darcy’s equation - a question of scale

Permeability from first principles

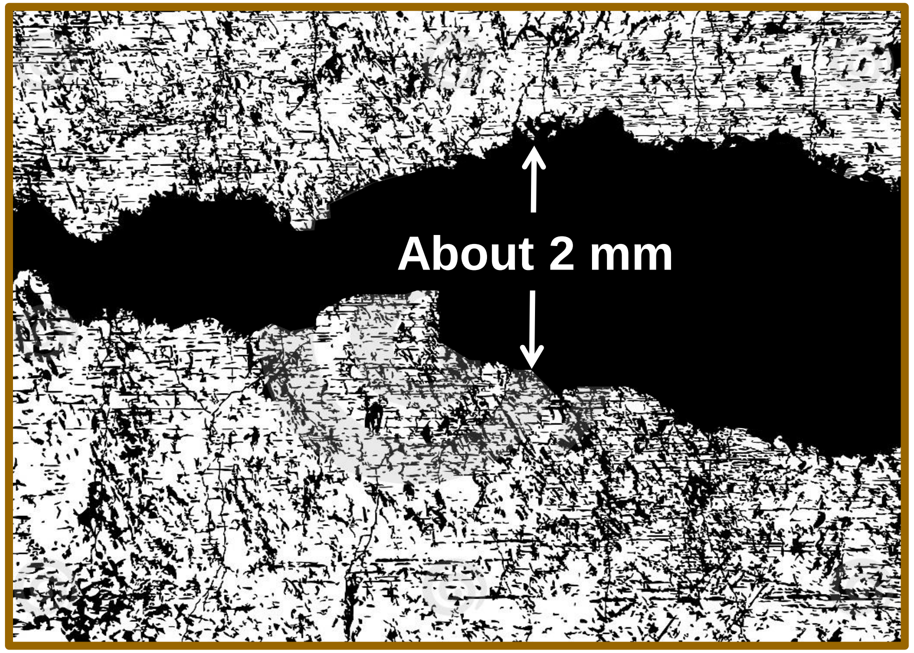
Commonly used formula for a single fracture:

$$\boxed{k_{fr} = \frac{w^2}{C \times 12}}$$

$k_{fr} = permeability\ of\ single\ fracture\ [L^2]$

$w = width\ of\ fracture$

$C = calibration\ constant$



- Based on Navier-Stokes equation
- Simplifying conditions (very limiting!):
  - steady state laminar flow of
  - single phase and
  - incompressible
  - viscous fluid through
  - regular slit (constant width) under
  - isothermal conditions subject to
  - viscous forces
  - (no gravity, no capillary pressure)

Dream on!!

- If all conditions apply, then C=1
- Experience suggests **C = 5 to 50**
- Important to know how it changes with pressure

We will <u>overestimate</u> fracture permeability if we ignore rugosity, tortuosity and continuity

The poroperm closed loop

Permeability must be calibrated with PTA of DST

$$\bar{k} = k_{fr}\frac{w}{l} = \frac{w^3}{C \times 12 \times l} = \frac{w^2}{C \times 12} \times \emptyset_f$$

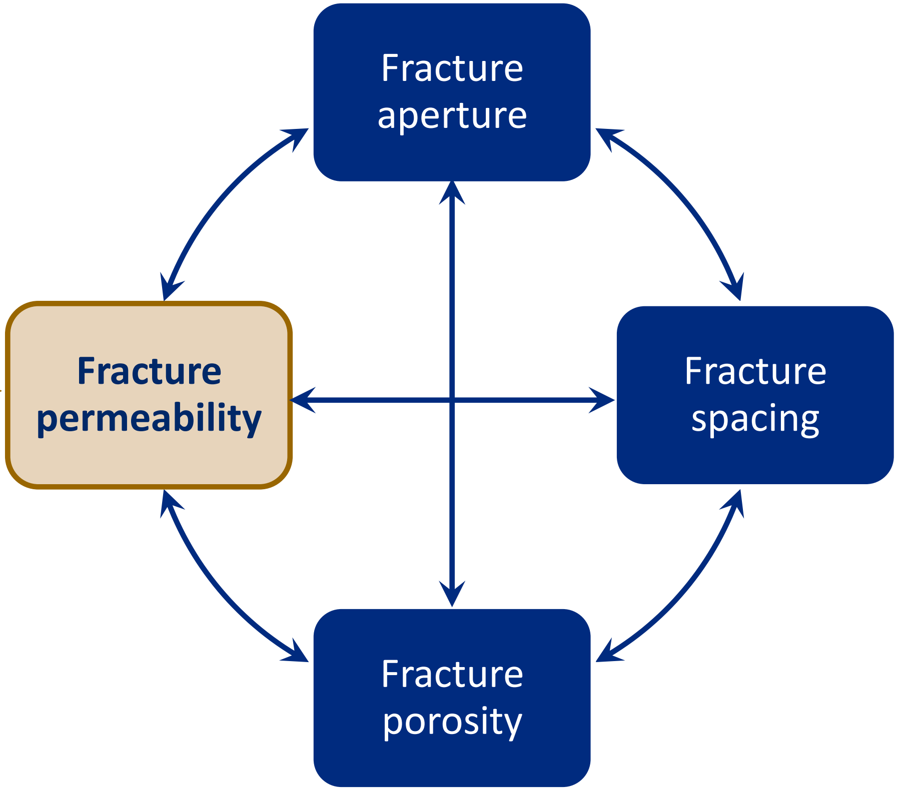
$\bar{k} = permeability\ of\ fracture\ network$

$\emptyset_f = porosity\ of\ fracture\ network$

$l = fracture\ spacing$

Calibration Constant (C):

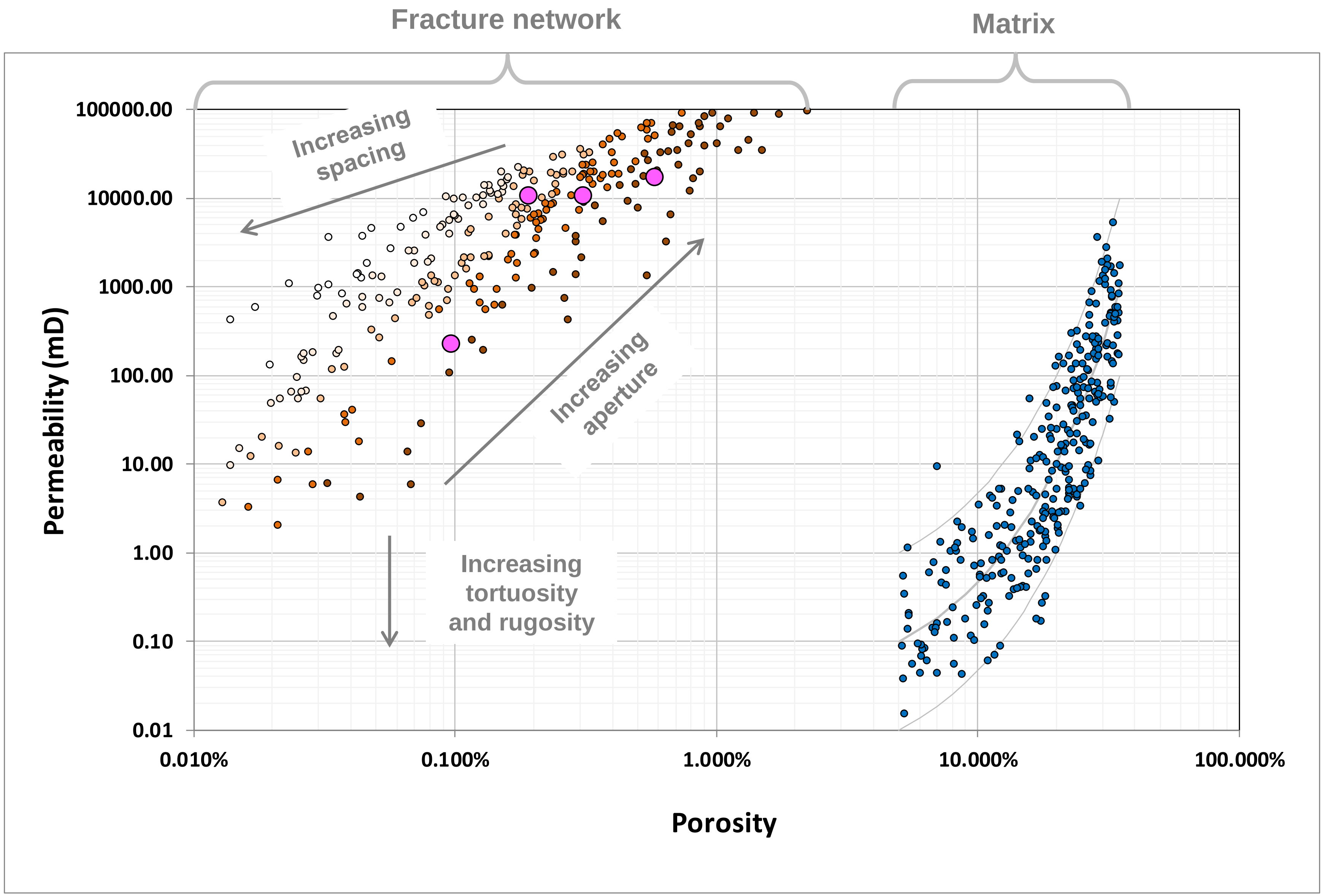
- rugosity
- tortuosity
- continuity



We will underestimate fracture porosity from permeability (DST) and spacing (image logs) if we ignore rugosity and tortuosity

From any two properties, the other two can be estimated

Poroperm transforms



Fracture porosity:

- Small values
- Span a wide range
- Associated with high permeability
- Often over-estimated (due to high flow rates?)

Understanding the relationship between the key parameters; porosity and permeability, in both the matrix and the fractures, is central to estimating recovery.

Concluding Observation

The more successful developments of naturally fractured reservoirs are often those that have been approached cautiously with a phased development plan.

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Acknowledgements and References

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