The Challenge of Estimating Recovery from Naturally Fractured Reservoirs

Dr Shane Hattingh
Principal Reservoir Engineer, ERC Equipoise
Disclaimer

ERC Equipoise Ltd ("ERC Equipoise" or "ERCE") has made every effort to ensure that the interpretations, conclusions and recommendations presented herein are accurate and reliable in accordance with good industry practice. ERC Equipoise does not, however, guarantee the correctness of any such interpretations and shall not be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from any interpretation or recommendation made by any of its officers, agents or employees.
Recovery Factors: what do they really mean?
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” \(^2\)

---

\(^1\) Firoozabadi, A., 2000.
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

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

‘Static’ data

\[
UR = \frac{GRV \times NTG \times \phi \times (1 - S_w)}{B_o,g} \times (RF)
\]

‘Dynamic’ part influenced by many factors

Double up for fractured reservoirs

Recovery factors and production forecasts are intrinsically linked
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

quantify RF uncertainty due to aquifer
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

- In fractured reservoirs, this might work:

\[ q_t = a_0 \frac{1}{R_t} - b_0 \]

- Late life data defines trend

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

\( R_t = \text{oil recovery at time } t \)
\( a_0 = \text{capillary pressure term} \)
\( b_0 = \text{gravity term} \)

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

1. Select representative matrix blocks
2. Idealise matrix blocks (properties)
3. Model matrix blocks
4. Upscale fracture network
5. Create fracture network mesh (grid)
6. Characterisation of fractures
7. Fractured reservoir
8. 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
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

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

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.
Fracture porosity and permeability
The use of Darcy’s equation - a question of scale
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)

If all conditions apply, then $C=1$

Experience suggests $C = 5$ to $50$

Important to know how it changes with pressure

We will overestimate fracture permeability if we ignore rugosity, tortuosity and continuity

Commonly used formula for a single fracture:

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

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

$w = \text{width of fracture}$

$C = \text{calibration constant}$
Fracture aperture
Fracture spacing
Fracture porosity
Fracture permeability

From any two properties, the other two can be estimated

Permeability must be calibrated with PTA of DST

\[ \bar{k} = k_{fr} \frac{w}{l} = \frac{w^3}{C \times 12 \times l} = \frac{w^2}{C \times 12} \times \phi_f \]

\( \bar{k} \) = permeability of fracture network  
\( \phi_f \) = 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
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.
Acknowledgements

ERCE, for sponsoring my attendance.

Webpage: www.erceequipoise.com
Contact: Nigel Dodds, NBD: ndodds@erceequipoise.com

Finding Petroleum, for organising the event.

Jon Gutmanis, for the fruitful discussions on fractured reservoirs over the years.

References

Allan J. and S. Qing Sun, 2003. Controls on Recovery Factor in Fractured Reservoirs: Lessons Learned from 100 Fractured Reservoirs. SPE 84590 presented at the SPE Technical Conference and Exhibition held in Colorado, 5 to 8 October.

Allan, J and Qing Sun, S., 2003. Controls on Recovery Factor in Fractured reservoirs: Lessons Learned from 100 Fractured Field. SPE 84590.


Jon Gutmanis, personal communication.
