

Petrophysical fracture identification for rock physics studies

Jun Yan, Liwei Lu, Rudi Lubbe and Simon Payne

Ikon Science Ltd, Causeway House, Teddington, London, TW11 0JR, UK

SUMMARY

Fractured carbonate reservoirs contain an important proportion of the world's hydrocarbon reserves and a qualitative and/or quantitative description of the fracture system is fundamental to petrophysical evaluations. Formation Micro Imager (FMI) or Formation Micro Scanner (FMS) logs aid in improving our understanding of fracture properties, but conventional logs are also still very useful as they can provide essential fracture information. However, if these image logs are not available in fractured reservoirs that will result in the presences of fracture to be ignored and the petrophysical stage will fail to provide correct log data. These errors will then inevitably be propagated into any subsequent well based rock physics or AVO analysis. The method of Fracture Comprehensive Probability (FCP) in our study has been proposed for fracture porosity modelling. This method, not only indicates the location of fractures using a synthetic image, but also calculates rock properties such as fracture porosity and fracture aperture which are useful for rock physics studies.

The estimation of fracture parameters is fundamental to the petrophysical evaluation of both carbonate rocks and fractured sandstone reservoirs. Well based image logs (FMI/FMS) are commonly used to interpret fracture parameters. However, these logs are not always available. This abstract describes a methodology, the fracture comprehensive probability (FCP), which uses conventional petrophysical log data to interpret essential fracture parameters. The FCP approach generates synthetic image logs and derives the properties of fracture porosity and aperture. A case study from a gas saturated carbonate reservoir is also shown. A significant difference is observed in the AVO response of the reservoir when the fracture parameters are incorporated in the modelling. It is concluded that the FCP methodology is an important precursor to rock physics studies when fracturing is expected to be significant but image log data are unavailable.

Methodology

Understanding fracture control factors helps to reduce risk for rock physics modelling and can improve reservoir parameter prediction. The FCP method creates a link between conventional wireline logs and image logs via the generation of a synthetic fracture image. This approach may indicate the location of fracture zones and it can also calculate fracture properties such as fracture porosity and aperture. The FCP workflow is shown in Figure 1.

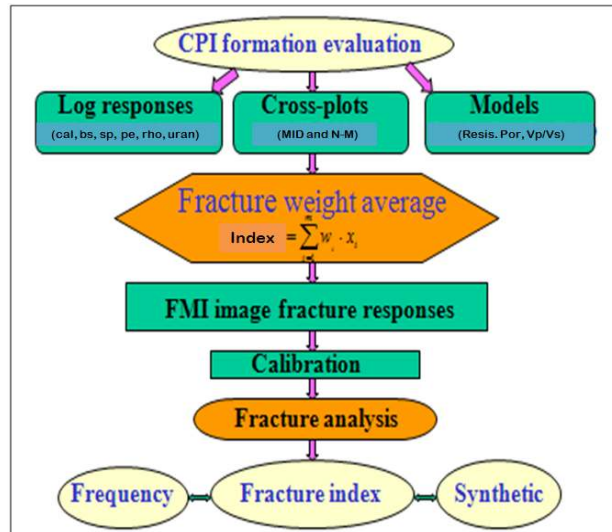


Fig. 1 Fracture comprehensive probability (FCP)

Step 1: Identifying fractures qualitatively

- **Fracture response on logs:** There is potentially a range of conventional petrophysical logs that can be interpreted qualitatively to indicate the presence of fractures. Table 1 is a summary of fracture responses from conventional logs.
- **MID cross-plot:** Figure 2 (left) gives a relationship of apparent-matrix density (g/cm^3) and its apparent-matrix transit time ($\mu\text{s}/\text{ft}$) in a fractured reservoir. It can be seen, the data points from the fractured region plot towards the left of the graph.
- **M-N correlation:** M and N of the petrophysical properties are derived from a series of porosity logs (such as DEN, NPHI and DT), and the presence of fractures can be identified based on a cross-plot of M-N. Data points from the fractured region plot near the top of the graph in Figure 2 (right).

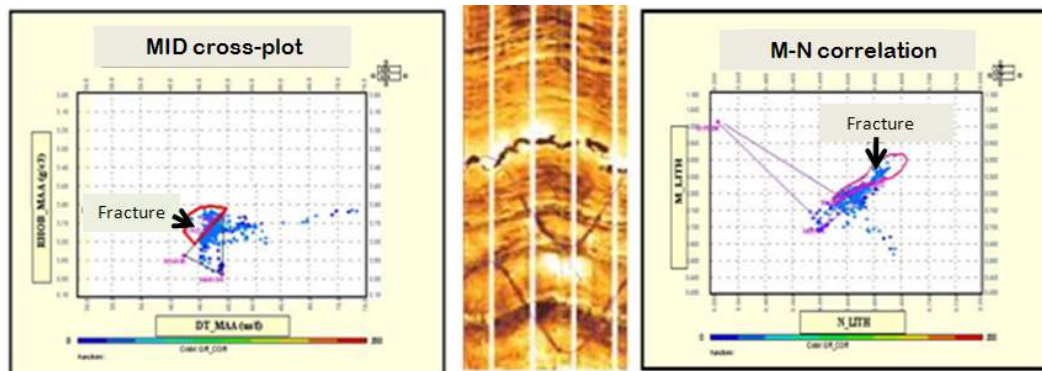


Fig. 2 Fracture identification: MID plot (left) and M-N correlation (right)

	Log name	Response	Description or note
CALI	Calliper log	Size change	Sudden variations indicate a discrete feature
SP	Spontaneous potential log	Anomalous	Need to refer to other related factors
GR	Gamma-Ray log	Anomalous	Low background readings
DT	Sonic log	Apparent value change	Using porosity to compare with DEN/NEU porosity
FDC	Formation density log	A sharp drop	Combined with PEF for an open fracture.
LLD, LLS	Deep and shallow resis. log	LLD> or <LLS	Fluid zone, LLD>LLS high angle, LLD<LLS low angle
PEF	Photo-electric factor log	High value with sharp drop	PEF and DRHO in a similar way
DRHO	Density correction log	High value	CALI no variation and Rxo has a low value for fracture
U	Uranium log	High value in open fractures	Need considering radioactivity effects
TEMP	Temperature log	Low value	Need to consider the effects due to mud invasion
m	Cementation factor	Low value	Considering POR-RT plot ($1.1 < m < mb$)
Vp/Vs	Ratio of Vp and Vs velocity	High value	Used for a stable borehole and known lithology

Table 1: Fracture response based on the conventional well-logs

Step 2: Calculating fractures properties quantitatively

- **Porosity fracture index (ϕ_{f_index}):** If a fractured formation can be considered as a dual porosity system then the effective porosity consists of both matrix porosity and a secondary (fracture porosity). The effective porosity, calculated from the sonic log, is sensitive to the inter-granular porosity. Meanwhile, the porosity calculated using the neutron and density logs included the fracture porosity (Yan 2008). The equations below give the relationships between fracture porosity (ϕ_f), fracture porosity index (ϕ_{f_index}), neutron- density porosity (ϕ_{ND}), density porosity (ϕ_D), sonic porosity (ϕ_s) and neutron porosity (ϕ_N).

$$\phi_f = \phi_{ND} - \phi_s, \quad \phi_{f_index} = \frac{|\phi_{ND} - \phi_s|}{\phi_{ND}}, \quad \phi_s = \frac{DT - DT_{ma}}{DT_f - DT_{ma}} \cdot \frac{1}{cp}, \quad \phi_{ND} = \sqrt{\frac{\phi_D^2 + \phi_N^2}{2}}$$

- **Resistivity fracture index (R_{ϕ_index}):** The resistivity fracture index predicts fracture information quantitatively based on mud filtrate invasion principles. It is calculated based on the deep and shallow resistivity logs in fractured zones for different hydrocarbon and water zones.

$$R_{\phi_index} = (R_{mf} \cdot [\frac{1}{R_s} - \frac{1}{R_d}])^{\frac{1}{m}} \text{ (Oil/Gas zone)} \quad R_{\phi_index} = \left(\frac{(\frac{1}{R_d} - \frac{1}{R_s})}{(\frac{1}{R_w} - \frac{1}{R_{mf}})} \right)^{\frac{1}{m}} \text{ (Water zone)}$$

where R_{ϕ_index} is the resistivity fracture index, R_{mf} is the mud filtrate resistivity, R_w is the formation water resistivity, R_d is the deep resistivity laterolog, R_s is the shallow resistivity laterolog and m is the cementation factor.

- **Fracture aperture (ε):** The estimation of fracture aperture has been provided by Sibbit (1985), which assumed that fractures were randomly distributed. Both horizontal and vertical fracture aperture (ε) are estimated based on equations below using dual resistivity laterologs (LLD, LLS) and mud filtrate resistivity (R_{mf}). A correlation between fracture porosity and fracture aperture is shown in Figure 3.

$$\varepsilon = \left(\frac{1}{R_{lls}} - \frac{1}{R_{lld}} \right) \cdot \left(10^4 / \left(\frac{0.4}{R_{mf}} \right) \right) \quad (\text{Vertical})$$

$$\varepsilon = \frac{\left(\frac{1}{R_{lld}} - \frac{1}{R_{lls}} \right) \cdot 10^4}{1.2 \frac{1}{R_{mf}}} \quad (\text{Horizontal})$$

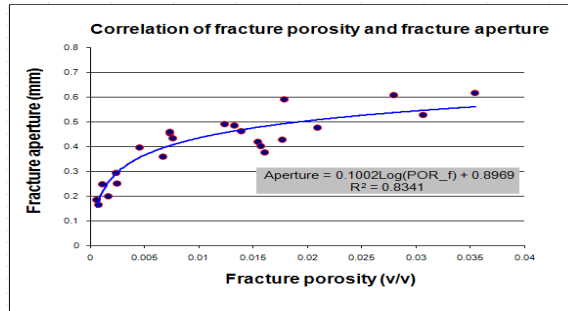


Fig. 3 The correlation of fracture porosity and aperture

Implementation and case study

The FCP method generates the probability of a fracture existing. This function, COMP, is calculated as the weighted sum of petrophysical parameters. The weights are assigned based on an interpretation of the reliability of the parameter to detect the presence of fractures. The probability can be displayed as a synthetic FMI image on the CPI plot (Figure 4). The key steps for implementation may be summarised as follows:

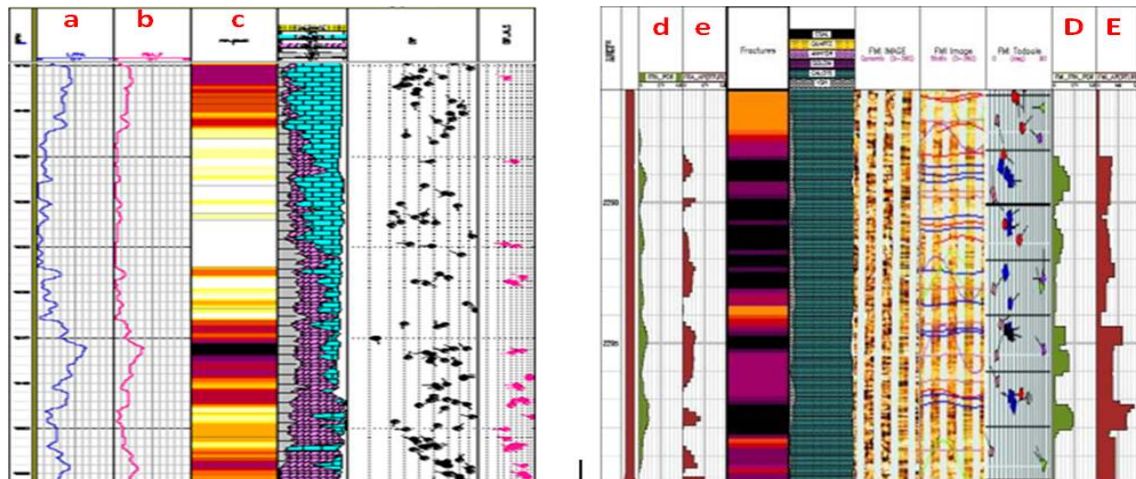


Fig. 4 Fracture indication based on FCP method (left) and calibration to FMI (right)

- Determine the fracture thickness (h_i) in depth (H) and calculate the fracture effect value using $P_i = h_i / H$. Then estimate the weight for each thickness ($w_i = P_i / \sum_{j=1}^m P_j$) and calculate fracture probability $COMP = \sum_{i=1}^m w_i \cdot x_i$ (where x_i is the fracture parameter and w_i is the fracture weight).
- The calculated fracture probability (COMP) is calibrated to the FMI log. The calibrated fracture probability is then used to build relevant correlations to determine fracture properties such as fracture porosity and fracture aperture.

An example using the FCP method in a carbonate formation is shown in Figure 4 (left). The FCP method generates estimates of: fracture porosity index (a), resistivity fracture index (b) and a synthetic fracture image plot (c). Also shown in Figure 4 (right) is the calibration of the FCP method to FMI data. A comparison can be made between fracture porosity (d), porosity aperture (e) derived using the FCP method and fracture porosity (D) and fracture aperture (E) derived from the FMI log. It can be seen in Figure 4 (right) there is a good correlation

between the fracture porosity and fracture aperture predicted by the FCP method (d and e) and the measured FMI logs (D and E).

Carbonate rocks exhibit complicated pore textures. However, in practise, the Gassmann equations (1951) are still valid for porous media of any lithology if the observation frequency is low and the background matrix is tight (Han, 2007). Figure 5 shows a comparison between synthetic gathers generated assuming the conventional porosity log (PHIE) and a fracture porosity log from FCP calculation. The tracks refer to the following: (a) Volume set; (b) Saturation set; (c) Vp (m/s); (d) Vs (m/s); (e) Density (g/cc); (f) Conventional PHIE (in red) and fracture porosity log from FCP (black); (g) Initial gather calculated from Vp, Vs and Density; (h) Oil 80% gather using FCP; (i) Oil 80% gather using PHIE; (j) difference between (h) and (i); (k) Gas 90% gather using FCP; (l) Gas 90% gather using PHIE; (m) difference between (k) and (l); The difference plots in tracks (j) and (m) suggest that the fracture porosity needs to be taken into account in AVO studies, as a stronger dimming response is encountered at the top of the lower reservoir level (indicated by the horizontal red line) if one takes into account the FCP calculated fracture porosity log.

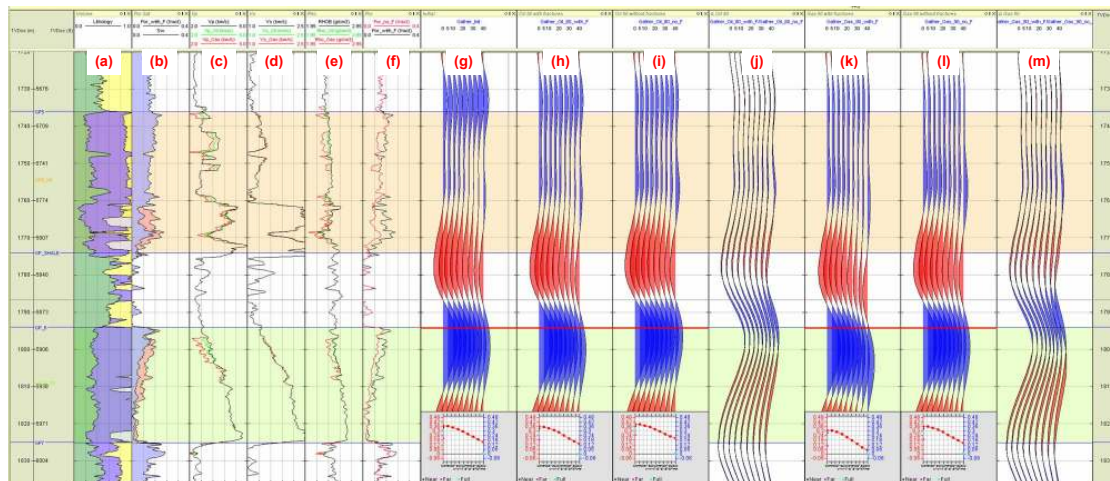


Fig. 5 Fluid substitution effect on AVO with and without considering fracture porosity, as derived from the FCP method, for 80% oil (tracks h and i) and 90% gas (tracks k and l).

Conclusion

The fracture comprehensive probability (FCP) is presented as a method to interpret essential fracture properties from conventional petrophysical log data. The FCP approach generates a synthetic image log that can be calibrated to FMI image logs. A case study from a gas saturated carbonate reservoir is also shown for the case study. A significant difference is observed in the AVO response of the reservoir when the fracture parameters are incorporated in the modelling. It is concluded that the FCP methodology is an important precursor to rock physics studies when fracturing is expected to be significant but image log data are unavailable.

References

- Gassmann, F., [1951]. Elastic waves through a packing of spheres: *Geophysics* **16**, 673-685.
- Han, D., H., [2007]. Velocity of Carbonate Rocks, CSRPB, University of Houston, Vol. No. P1-8.
- Sibbit, A.M, and Faivre, O., [1985]. The Dual laterolog response in fracture rock. SPWLA 26th Symposium.
- Yan, J., Lubbe, R., and Pillar, N., [2008]. Modified velocity model for seismic study via AVO, *Journal of Seismic Exploration*, Vol. **17**, p371-390.