Fractured Reservoir Characterization from Seismic Azimuthal Anisotropy and Well Log Analysis

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Summary

The performance of naturally fractured reservoirs is controlled by the orientation, intensity and spatial distribution of open fractures. In this paper we present the results of a recent fracture characterization study based on *P*-wave azimuthal anisotropy using interval velocities and RMS amplitude maps. A consistent processing sequence was applied to all azimuth sectors in order to preserve the quality of the azimuthal anisotropy information. A proprietary geostatistical decomposition technique was applied to ensure more stable and accurate estimates of the fracture intensity and direction. These results provide detailed maps of the fracture system and show good correlation with sub-seismic scale fracture analysis from FMI/ FMS logs.

Introduction

An accurate knowledge of fracture networks is critical for the optimization of the development of naturally fractured reservoirs, since intensity and orientation of fractures significantly affect fluid flow in the reservoir rocks. Although numerous methods based on shear-wave splitting analysis are available for fracture detection, a growing interest in *P*-wave azimuthal amplitude variation has been observed in the last few years. Rüger and Tsvanskin (1997) demonstrated that reliable estimates of the anisotropy parameters could be obtained from *P*-wave amplitudes. The approximations of the reflection coefficients of Rüger (1998) were then extended into a linearised form by Jenner (2002). Angerer et al. (2003) then went on to propose an integrated approach for fracture characterization, which yields quantitative estimates of fracture intensity and direction from wide-azimuth, large offset *P*-wave data. In this paper we apply this workflow to a 3D seismic dataset of approximately 20 km^2 and investigate two distinct reservoirs. To confirm the validity of the estimated anisotropy attributes this study included an analysis of the fracture network on a sub-seismic scale using image log data from 6 wells.

Azimuth-friendly processing

In the applied workflow, a detailed review of the acquisition geometry and the processing sequence is performed to ensure preservation of the azimuthal anisotropy information. This is followed by optimization of the binning grid to generate a homogeneous offset and azimuth distribution. The number of azimuth classes and the offset range is selected on the basis of the signal-to-noise ratio and average fold with an iterative process that takes into account the various macro-binning options. There is a trade off between the macro bin size and the number of azimuth sectors, which affect either the lateral resolution or the robustness of the anisotropy attributes computation. The best combination was obtained for a 5x5 macro bin size, 4 azimuth sectors and an offset range of 500-1400 m. This corresponds to a maximum incidence angle of 35-40 degrees for the shallower target and 20-25 degrees for the deeper target. For each of the azimuth sectors some RMS amplitude maps are extracted from time windows of 100 ms thickness centered on each of the two reservoirs. In addition, automatic high density velocity picking was performed in order to produce accurate azimuthal NMO velocities from which we were able to derive an interval velocity map.

Geostatistical decomposition and anisotropy extraction

A proprietary Geostatistical decomposition is applied to the interval velocity map and the RMS amplitude maps in order to separate the anisotropy component of each azimuth sector from the noise. We also extract the common part of all azimuth sectors, which is considered to be the geological or isotropic information. The geostatistical decomposition is based on the automatic factorial co-kriging (AFACK) technique developed by Coléou (2002). This provides an effective means of building spatial filters from the automatic decomposition of the variogram and crossvariogram functions, which can enhance the spatially coherent information in the data.

The four noise-free azimuthal amplitude or velocity maps are combined in order to estimate the orientation and magnitude of the anisotropy. Calculation of these anisotropy attributes is performed using a linear least squares fitting algorithm that constrains the elliptical distribution of the azimuthal anisotropy variation. The magnitude of this ellipse is proportional to the fracture intensity and the azimuth of the maximum elliptical amplitude is related to the fracture orientation. Figure 1 presents the results of an ellipse fitting with and without the application of geostatistical decomposition prior to the anisotropy extraction. The blue points represent the data from each azimuth sector, the solid line is the fitted ellipse and the dashed lines are the fitting error. The improvement resulting from the geostatistical filtering can be clearly observed (Figure 1b). There is a better estimation of the elliptical variation of the data and thus a more accurate estimation of the anisotropy attributes.

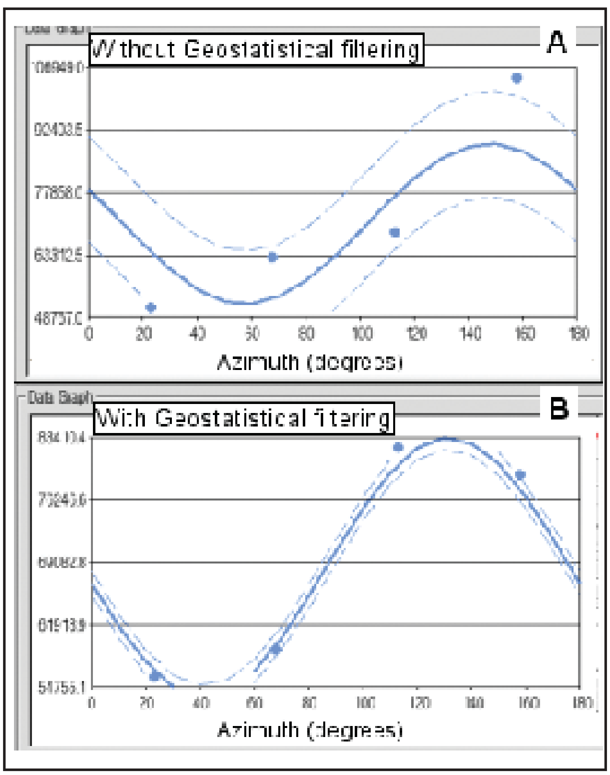

Fig. 1: Examples of the ellipse fitting with and without the application of geostatistical decomposition prior to the anisotropy extraction. The elliptical variation of the anisotropy is better constrained after geostatistical filtering. This ensures a more accurate estimate of the intensity and direction of the anisotropy.

Analysis of the results and comparison with well data

The anisotropy maps obtained from the RMS amplitude are presented in Figures 2a and 2b. The most heavily fractured zone is located in the South-West part of the survey close to an East-West striking platform margin. The anisotropy map extracted for the deeper reservoir (Figure 2b) presents some anisotropy patterns that appear to be related to an acquisition imprint. This can be largely

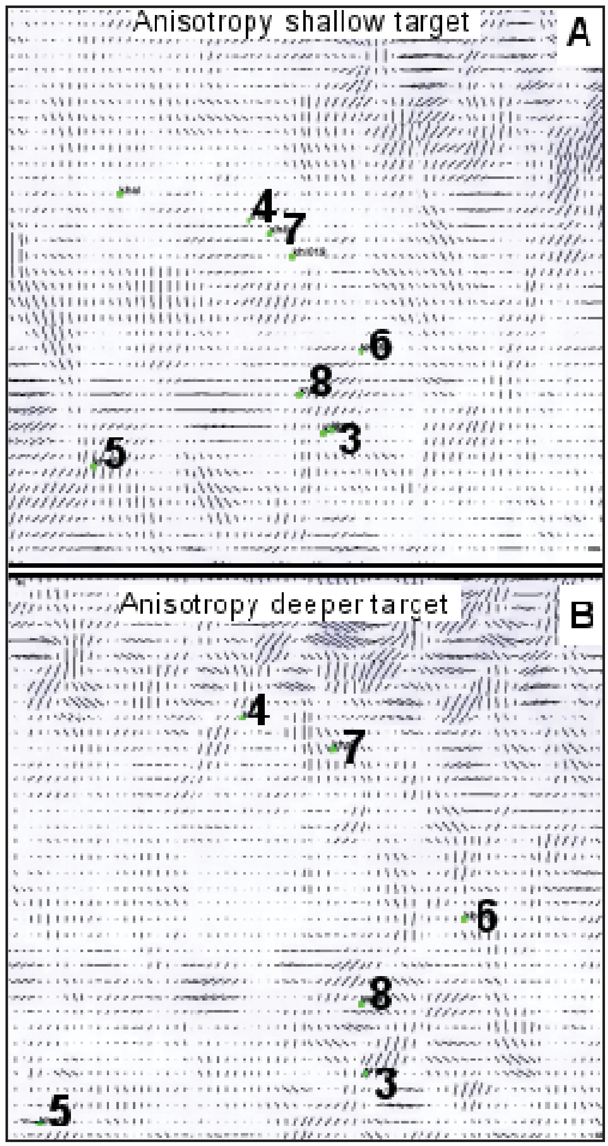

Fig. 2: Anisotropy maps of the shallow reservoir (a) and deeper reservoir (b) computed from RMS amplitude maps. A detailed characterization of the fracture network can be observed. The anisotropy intensity is given by the length of the vectors and the direction is shown by the orientation of the vectors.

attributed to the non-orthogonal acquisition geometry, which makes it difficult to obtain a uniform azimuthal distribution.

A set of FMI/FMS logs from 6 wells was analysed within which a complex structural setting can be observed and some major faults detected. Figure 3b displays the fracture count at the boreholes of various fracture classes. Note that in this study we only take into account the conductive continuous fractures (represented in blue). The effect of discontinuous fractures as well as resistive fractures on seismic anisotropy is negligible. Comparison of the image logs with the seismic anisotropy maps reveals a high degree of correlation between the observed fracture intensity and the estimated anisotropy intensity, as can be seen from Figure 3a which presents the anisotropy map at the main reservoir level obtained from interval velocity analysis. The local anisotropy intensity is given by the length of each individual vector and the anisotropy direction is shown by the orientation of the vectors. Two low intensity regions (circled in blue) are visible around well 3 and between wells 4, 7, and 6, while a strong fracturing is seen around wells 5 and 8 (circled in red). In Figure 4, the fracture intensity observed at the wells is cross-plotted against the estimated seismic anisotropy intensity, with the results obtained from interval velocity analysis shown in Figure 4a and those from RMS amplitude analysis in Figure 4b.

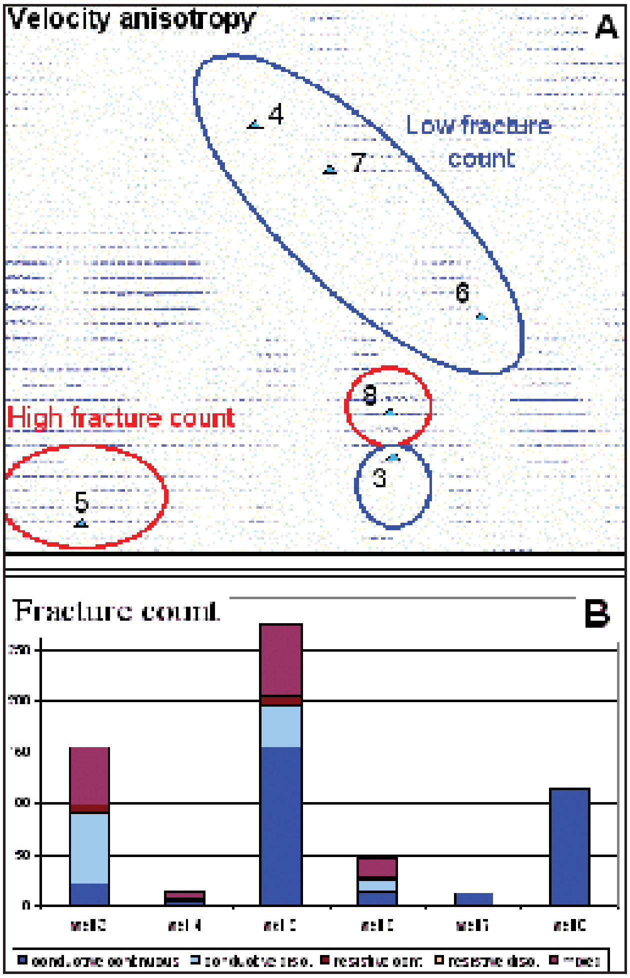

Fig. 3: (a) Anisotropy map computed from the interval velocity. (b) Fracture count for various fracture classes. Note that only conductive, continuous fractures (shown in blue on the fracture count) are considered in this study. A good fit is obtained between calculated intensity and the actual fracture density observed at the wells.

These cross-plots, again suggest a good correlation between the low and high fracture density regions at the wells and the estimated anisotropy intensity. In addition it can be noted that there is still a low anisotropy intensity even when no fractures are observed at the wells. This may indicate that the seismic anisotropy is also influenced by the stress regime present in the area.

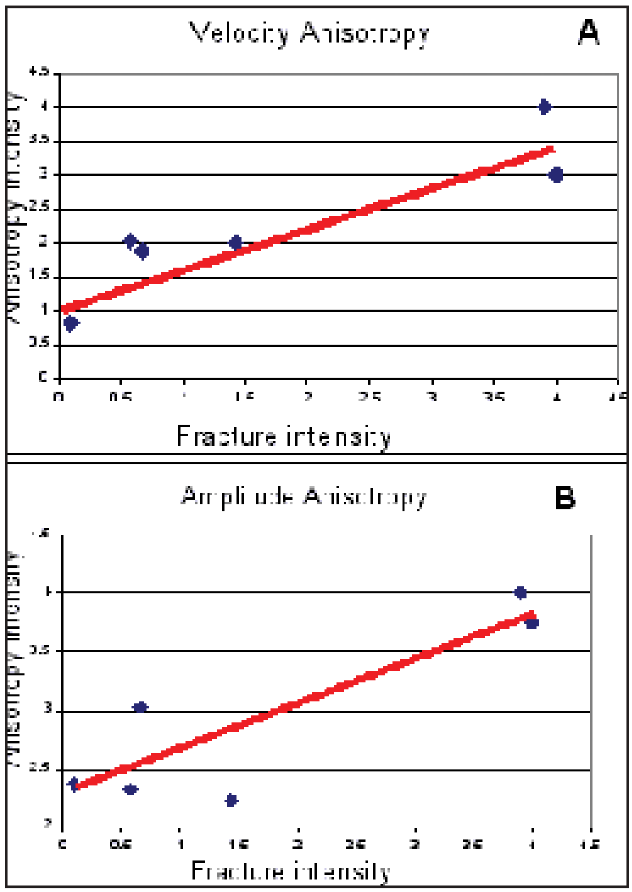

Fig. 4: Cross-plots of the fracture intensity observed at the wells with the estimated fracture intensity from (a) interval velocity analysis and (b) RMS amplitude analysis. Areas of low and high intensity correlate well.

A comparison of the fracture strike direction derived from the image log and the corresponding seismic anisotropy orientation is shown in Figure 5. The observed fracture orientation is represented by blue points while the estimated orientation is shown in red for the RMS amplitude and in pink for the interval velocity. A good match is observed for the anisotropy direction derived from amplitude maps, particularly at the highly fractured wells.

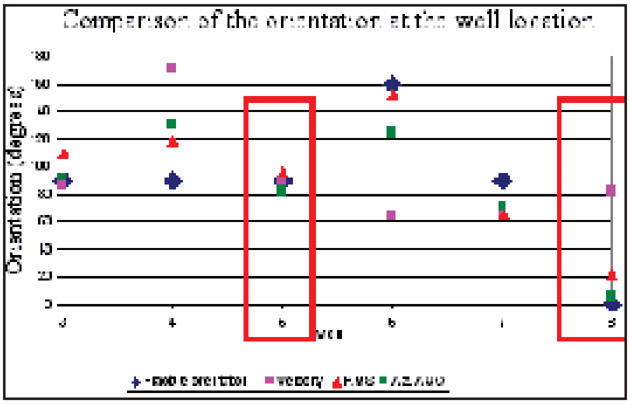

Fig.5: Comparison of the fracture orientation observed at the borehole with the estimated orientation. In general, a better correlation is observed at wells presenting a high fracture density (circled in red). The estimated amplitude anisotropy orientation values are more accurate than the velocity anisotropy orientation. This is due to the greater spatial resolution of amplitude data compared to velocity measurements, since velocity measurement sample a large volume.

The drift of the orientation values at wells 4, 6 and 7 may be caused by the low values for the anisotropy intensity increasing the ambiguity in the ellipse fitting process and thus generating greater uncertainty in the anisotropy orientation value. This effect seems to have a greater impact on the extraction of the orientation from interval velocity. Despite high fracture intensity at well 8, the estimated velocity anisotropy direction shows a 90degree shift from the observed orientation. This is attributed to the lateral smoothness of the velocity measurement which samples a greater volume compared to the amplitude data.

It can be concluded that the use of amplitude data is beneficial for seismic anisotropy extraction as it leads to a more detailed and accurate estimation of the anisotropy attributes than the interval velocity.

Conclusions

The intensity and orientation of open fractures can have a significant impact on the performance of carbonate reservoirs. Therefore an accurate quantification of these seismic anisotropy attributes is essential. In this paper, we have applied an integrated seismic fracture characterization workflow to a 3D seismic land dataset and have shown that a quantitative estimate of the fracture network can be obtained from wide-azimuth, large offset *P*-wave data. Well log analysis demonstrated that the fracture intensity and fracture strike direction derived from high resolution image logs (FMI/FMS) correlate with the anisotropy intensity and orientation estimated from the seismic. This confirms the robustness of the workflow for determining quantitative seismic azimuthal anisotropy attributes.

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