Stress identification with an azimuthal inversion technique – a case study for a clastic oil field.

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Summary

Azimuthal inversion is state-of-the-art inversion technology for stress and fractured reservoir characterization and detection in anisotropic media. This technology requires a wide-azimuth seismic survey and careful azimuth dependent processing with noise attenuation.
In this paper, the influence of noise attenuation on the reliability of anisotropic inversion results is discussed. The implementation of this technology for the understanding of horizontal stresses and the verification of the results with well data and microseismic will be presented.

Introduction

Deterministic and geostatistical inversion methods are well known to interpreters and have already been included in standard reservoir characterization workflows. While reservoir models resulting from these techniques have been verified by drilling many times, characterization of anisotropic reservoirs is quite uncommon. For such types of reservoir the correct determination of the anisotropic properties is a key issue for identification of prospective areas and new well planning.

In this paper the implementation of azimuthal inversion for the estimation of horizontal stresses and verification of the results with well data and microseismic will be presented.

Method

Anisotropic inversion enables us to use quantitative isotropic modelling and inversion in anisotropic media. Based on the Rüger reflectivity equations for HTI media, (Rüger and Tsvankin, 1997) transforms are designed for the elastic parameters and then used in isotropic pre-stack inversion (P. Mesdag, 2015). At the first stage, the partial stacks of common azimuth seismic data are inverted to the elastic properties set (P-Impedance, Vp/Vs ratio and Density). In panel A of Figure 1, Vp/Vs ratio sections for different azimuth sectors are shown. During the second stage, azimuthal Vp/Vs volumes are used to estimate the anisotropy coefficient and azimuth of maximum anisotropy (Figure 1, panel B).

Influence of wide-azimuth processing on azimuthal inversion results

In anisotropy prediction from seismic data using cutting edge technologies it is important to keep in mind the azimuthal distribution of the seismic survey. Anisotropy studies can be reliable only for wide-azimuth surveys with sufficiently high fold of coverage, due to the fact that azimuthal inversion requires partial stacks with good signal-to-noise ratio for each azimuthal sector.

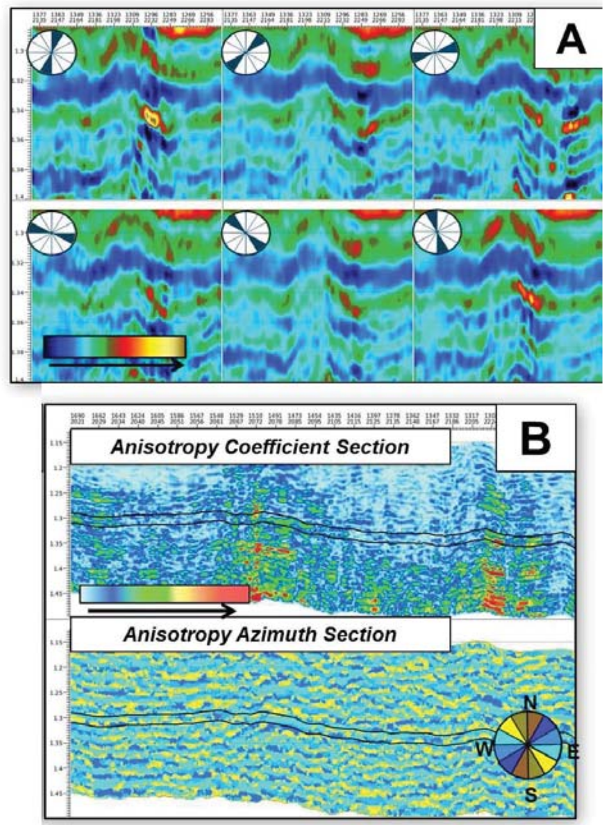

Figure 1: Figure 1. Pre-stack azimuthal inversion results (A - Vp/Vs ratio for different azimuthal sectors; B –Anisotropy coefficient and maximum anisotropy azimuth sections).

This study was conducted for an oil field covered by a 3D wide-azimuth survey with an average fold of 256 for near to mid offsets and a fold of up to 512 for far offsets. During the data processing stage, it was possible to create 5 partial offset stacks (0-600, 500-1100, 1000-1800, 1700-2400, 2300-3000 m) for each of 6 azimuthal sectors (0-30, 30-60, 60-90, 90-120, 120-150, 150-180°).

To obtain reliable results of azimuthal inversion, it is very important to carefully analyze not only the full-azimuth range full- and partial-offset stack data, but also the partial-offset stacks for each azimuth sector. Here it will be shown how efficient noise attenuation influences the anisotropy coefficient and the anisotropy azimuth prediction.

Simple comparison of full-offset stack sections calculated using the full range of azimuths but with different noise attenuation processing flows shows that they are similar. However, differences are evident when comparing full-azimuth partial-offset stacks. For partial-offset stacks of azimuth sectors the differences become even more obvious (Figure 2, B). On the lower section (processing #1) areas with low signal-to-noise ratio can be clearly identified and analysis of this noise for different azimuth sectors shows that it is different for different azimuths. It is exactly the variation of the seismic wavefield with azimuth which drives the anisotropy studies and it is important that these are not contaminated by noise.

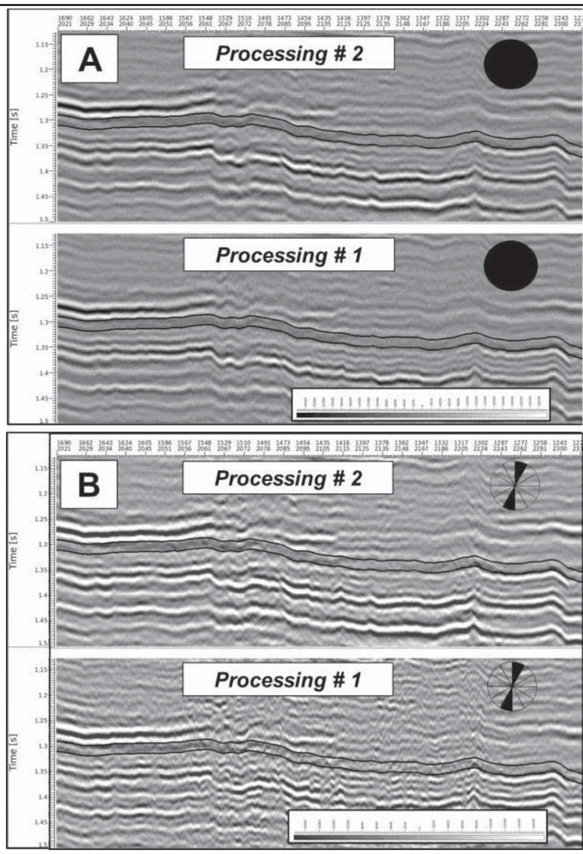

Figure 2: A - Comparison of seismic sections obtained with different processing flows : A) full stack, full azimuth sections; B) partial stacks in a azimuth sector

Consequently, azimuthal inversion results based on the processing # 1 flow show high lateral variability. Zones with low signal-to-noise ratio have a high correlation with highly anisotropic zones. These zones do not have any geological significance or explanation. This effect is due to insufficient noise attenuation during seismic data processing (Figure 3).

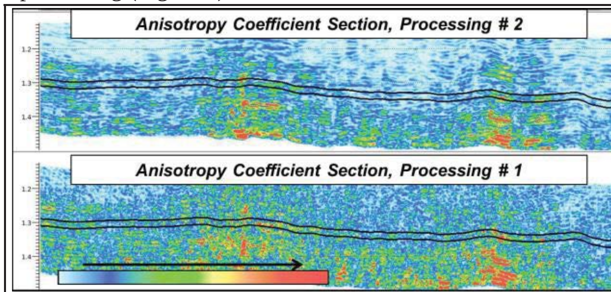

Figure 3: Comparison of anisotropy coefficient sections obtained from azimuthal inversion based on different seismic processing.

In Figure 3, the two panels show the anisotropy coefficients for the two different processing flows. After applying some additional noise attenuation (processing #2) the obtained anisotropy coefficient section shows more lateral and vertical stability: fully isotropic zones above the target interval and zones with a different magnitude of anisotropy within the target interval can be clearly identified. Random noise in the azimuthal inversion results has disappeared. The effect of the superior random noise attenuation achieved by processing # 2 can be seen even more clearly on the map views of the anisotropy coefficients within the target interval in the upper panels of Figure 4. Also the distribution of anisotropy azimuths looks more stable and can be interpreted geologically in comparison with the anisotropic azimuth map based on processing #1 which looks like random noise (Figure 4, lower panels).

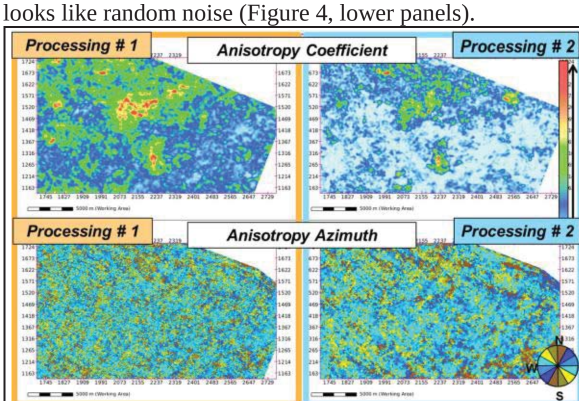

Figure 4: Comparison of the anisotropy coefficient and anisotropy azimuth map obtained from azimuthal inversion based on different seismic processing (processing #1, processing #2).

Interpretation of azimuthal inversion results

The best way to check the quality of azimuthal inversion is to verify it against parameters of anisotropy calculated from well logs. The limited range of available incident angles at the top of the target interval in this case study (up to 30 degrees) is not sufficient for reliable prediction of the magnitude of the anisotropy from azimuthal inversion, but it does seem sufficient to predict its azimuth. So the inverted coefficient of the anisotropy could not be directly compared with the cross-dipole S-sonic logs, but it could be used as an accurate measure of the azimuth of the anisotropy. Evidence of the quality of the predicted azimuth could come from different sources, such as cross-dipole S-wave well logs, walk-away VSP and microseismic. All the above-listed measurements were performed for a relatively small project area of about 300 sq. km. There are 7 wells with acoustic, log-derived azimuths of Vfast and one well with a walk-away VSP. Microseismic monitoring of multistage hydraulic fracturing had been done in one of the horizontal wells.

Seismic anisotropy is caused by differences in horizontal stresses. The azimuth of maximum horizontal stress is the same as the azimuth of Vfast and it is a crucial factor controlling the propagation direction of hydraulic fractures in seismic anisotropic media. Good knowledge of this information is critical for the optimization of the location and direction of new horizontal wellbores.

Comparison of the direction of the maximum horizontal stress from inversion and the azimuth of Vfast and walk-away VSP results at well locations is presented on Figure 5. The map shows anisotropy values in color, red arrows show the azimuth of predicted maximum horizontal stress and blue sectors represent the azimuth of Vfast from cross-dipole acoustic logs. The difference between the predicted azimuths of maximum horizontal stress and well data do not exceed one azimuthal sector. This range could be interpreted as the natural uncertainty of azimuth predictions when discrete azimuth ranges are used.

The reliability of the azimuth of the anisotropy from inversion was also proven by microseismic. It is the most compelling evidence to prove the accuracy of the inversion results and verify the significant lateral variations of the azimuth of the maximum horizontal stress caused by this complex tectonic system.

In one well there were 7 stages of hydraulic fracturing and the azimuths of the fractures for each hydraulic fraction stage were defined (Figure 6). Points of events corresponding to different stages have different colors. Interpreted fractures are shown as blue and green arrows. The main fault near the well is shown on Figure 6 as a red line. It is clear that the azimuth of the maximum horizontal stress changes near the fault and has a good correlation with the tectonic model. The wellbore of this horizontal well goes through the fault, dividing the well into two parts.

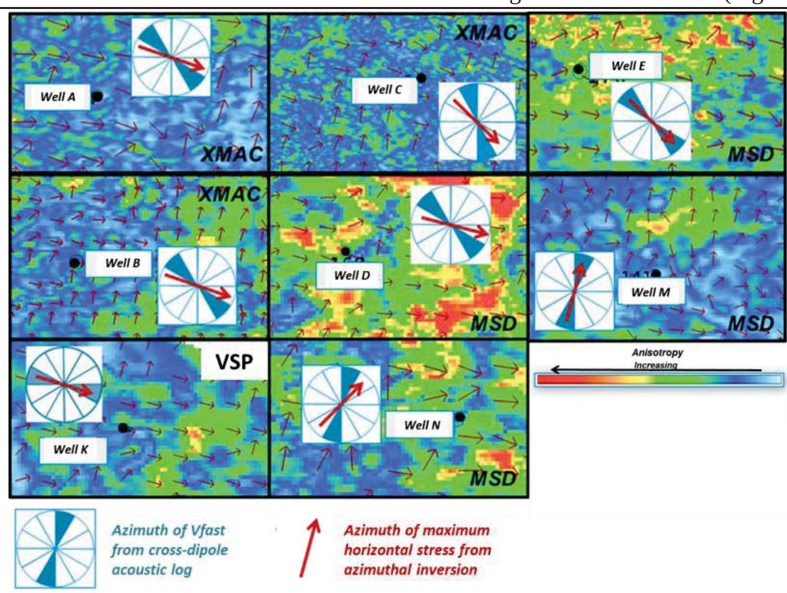

Figure 5: Comparison of the predicted azimuth of the maximum horizontal stress and of the azimuth of Vfast from cross-dipole acoustic logs and a walkaway VSP at one well location.

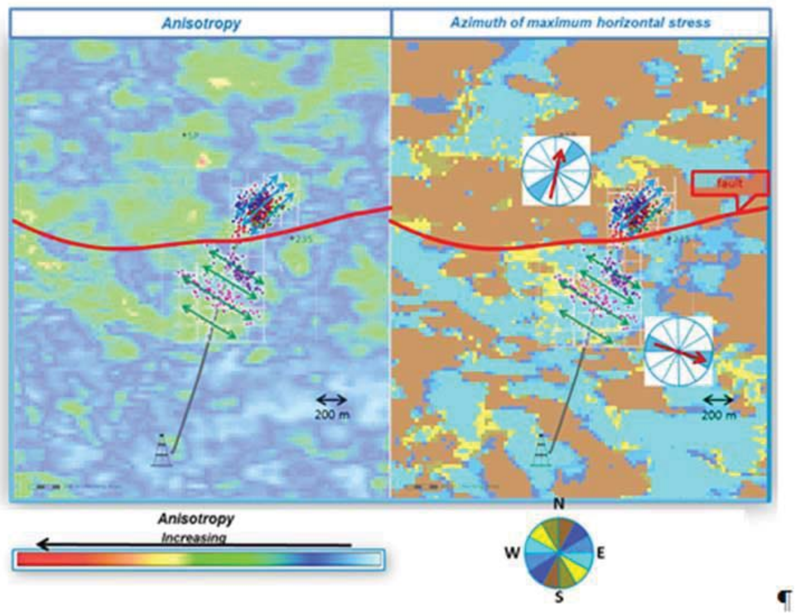

Figure 6: Comparison of the predicted azimuth of the maximum horizontal stress and the azimuth of the hydraulic fractures from microseismic.

According to the microseismic the azimuth of the fractures for the northern set is 50 degrees (2nd azimuthal sector) and the predicted azimuth is in the 1st sector. For the southern part, the azimuth of fractures is 120 degrees (the border between 4th and 5th azimuthal sectors) and the 4th azimuthal sector was predicted by azimuthal inversion.

Conclusions

The product of azimuthal inversion is not only volumes of anisotropy parameters but also a set of elastic property volumes for each azimuthal sector. In the presence of azimuthal seismic anisotropy, the reconstruction of elastic properties by azimuthal inversion is much better than by standard full-azimuth deterministic simultaneous inversion. As a result the interpreted reservoir distribution from the mean of the elastic properties for all azimuthal sectors has a better match with the lithology from wells than the one from standard full-azimuth simultaneous inversion. However it should always be taken into account that azimuthal inversion is very sensitive to noise attenuation during seismic processing. This means that noise attenuation has to be carefully tested and checked.

The results of anisotropic inversion helped to clarify the geological model of the field and to construct a 3D model of the reservoir characterized by a greater lateral stability consistent with well data Refinement of the spatial distribution of the reservoir enables the optimization of the location of new wells.

The predicted azimuth of maximum horizontal stress is a valuable source of information for horizontal well planning, where hydraulic fracturing is required. For the successful implementation of fracturing, a wellbore should be directed perpendicular to the azimuth of maximum horizontal stress. Thus, the correct determination of the anisotropic properties is a key to identification of prospective areas and new wells planning. This facilitates the optimization of development plans and the minimization of costs by reducing the number of wells producing at low flow-rates.

Acknowledgments

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EDITED REFERENCES

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