AVD - an emerging new marine technology for reservoir characterization
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Summary
Several significant developments in marine technologies have taken place over the past few years, resulting in the creation of acquisition techniques suited to seismic anisotropy analysis in the offshore environment. In fact the developments have paralleled the evolution in the theory underlying the use of P-P and P-S amplitude versus direction (AVD) for seismic anisotropy estimation. Indeed, the demands of such AVD methods for a wide azimuthal coverage have only recently been met. To guide future work, the AVD method has been assessed using data from orthogonal streamer lines. The results of this study provide confidence that the method is sufficiently sensitive to reservoir fractures, and help guide future analyses. It is our belief that the new generation of vertical cables, seabed seismic sensors, and walk-away (and/or 3D) VSPs will lead to high resolution anisotropy estimation in the offshore environment using this approach.

Why azimuthal anisotropy?
In recent years, it has been demonstrated that the equivalent medium theory may be further extended to include sub-seismic fracturing which gives rise to azimuthal anisotropy to seismic wave propagation (MacBeth 1995). Estimation of the fracture-induced seismic anisotropy determines the aggregate alignment and porosity of the fracture ensemble, provided knowledge of the type of fracturing is well determined. Such an insight is gained at the expense of individual detail for the constituents. Indeed, it now appears in principle that the role of seismic anisotropy could be to fill the gap between the fractures determined by logs, extrapolated from outcrop analogues, and inferred from seismic data. Other evidence suggests that only the fractures that flow influence the overall seismic response. A direct link between permeability and anisotropy has been observed in multi-component VSP, the result being shown in Figure 1. This result appears to make sense intuitively, as open conduits for flow will weaken the rock in the direction of the flow surface/network.

Estimation of azimuthal anisotropy
The first generation - land multi-component seismsics. Historically, azimuthal anisotropy and fractures have been almost synonymous with shear-waves. This is because the anisotropy effects on the shear waves are greatest at vertical incidence, and hence the method is suited to near-offset VSP and post-stack surface seismsics. This simple and direct approach was exploited in the first generation methods which relied upon direct excitation and recording of shear-waves in land multi-component acquisitions. Two shear waves are generally excited, each sensing the fractures differently. Such surveys detect fracture clusters by identifying dim spots in the top reservoir event when observed on the slower shear wave section. This approach has been successfully applied to locating fracture swarms in the Austin Chalk, Texas (Mueller 1991, Li 1995) using 2D lines, and guiding horizontal drilling into productive zones. The approach has also been employed in large 3D surveys (Davis and Lewis 1993). In this era, particular mention should also be made of multi-component VSPs. The technique has, and continues to provide much useful information on the relationships between shear-wave anisotropy and fracture or lithology (Winterstein and Meadows 1991; Horne and MacBeth et al. 1996). In spite of the many successes, multicomponent surveys are not shot on a routine basis, mainly due to the high cost in acquisition.

Figure 1. There may be a direct connection between the degree of seismic anisotropy (birefringence) and the flow of fluids (permeability) as shown here in measurements of multi-component VSP at the Conoco test-site in Oklahoma (Horne and MacBeth 1996, SEG Workshop, Bigsby, Montana).

The new generation - azimuthal variation of the P-wave signature in onshore data. Field acquisition for seismic anisotropy has reverted to using P-wave data to detect fracture-induced azimuthal anisotropy. For
vertical fractures, the most pronounced effect is usually when parallel and perpendicular to the fracture strike. When parallel to the fracture strike, fracture zones will not affect the waves. In contrast, when perpendicular to the fracture strike, the fracture zones will give rise to a sharp reduction in amplitude with offset. Three or more source-receiver lines can be used to map the behavior with direction, and hence derive fracture strike (Maillick et al. 1996). The evolution of field practice for this new generation method, started with a discussion of using land 3D data from the Paris Basin (Leefuwe 1994) and the proposition of binning according to azimuth and offset. Since then, the method has been successfully compared with the older multicomponent approach for a variety of fractured gas reservoirs where production is known to be affected by the fractures (Lynn et al. 1996). Other field examples of amplitude variations mount and interest continues to grow, whilst consideration is also being given to NMO velocity variations (Corrigan et al. 1996). Thus, from the land-acquisition perspective this new technique heralds an era of more inexpensive acquisition using traditional P-wave seismics.

The next generation: AVD - azimuthal variation of the P-wave signature in offshore data. For the marine environment, the approach described in the previous paragraph opens up a whole new area of interest and potential application. In particular, offshore data are quite suited to this approach, as they possess several advantages: flexibility in survey design, higher data quality and an optimum seismic anisotropic acquisition. In recent years, there have been new developments in the field of marine acquisition technology, such as seafloor seismics and vertical cable seismics. These are actually highly appropriate for the estimation of seismic anisotropy due to their wide azimuthal aperture. Such is their relevance, we may safely predict that they provide the next natural direction for marine studies of fractured reservoirs, which will form the next generation of methods. The approach of analyzing amplitude versus direction over multiple azimuths in these marine data is referred to as AVD. The acronym is chosen as it more accurately reflects the wide range of possible behavior due to general anisotropy, and draws a distinction from the different nature of land application.

Testing the feasibility of AVD

In this example we reveal the first evidence of a variation in the P-wave reflection amplitude with offset and azimuth for standard marine data in the UK North Sea (MacBeth et al. 1997). The data were shot in the Fife field, which is situated in the far south-eastern portion of the Central North Sea (Makertich 1996). Jurassic sandstones form the primary reservoir, but additional hydrocarbons have also been encountered in the 150m thick Chalk Group. There is estimated to be between 10 and 24 million barrels of oil. In this area there are many intersecting 2D lines of various vintages cutting across the crest of the field. We choose three lines which intersect the discovery well (L1) drilled directly into the oil-filled fractures (Figure 2) as this provides a well tie for wavelet shaping. The lines lie approximately parallel (A1) and perpendicular (W and A2) to the known local (Epsilon) fault, and shot with a standard 3km streamer. The Top Ekofisk is a very strong and reliable event across the whole of the field, and is used to provide a calibration horizon for the processing.

![Figure 2. Contours of the Top Chalk for the Fife field, together with a prediction of the hydrocarbon accumulation and acquisition lines (A1, A2 and W) for the AVD test.](image-url)

The analysis is guided by reflection coefficients calculated numerically for the top and bottom of the chalk group, and the results further verified by full wave anisotropic modelling of the CMP gathers. The calculation for the Bottom Chalk reflection (Figure 3) reveals a weak amplitude variation parallel to the fracture strike, but a marked decrease perpendicular to the fracture strike. In this particular case, the high chalk
velocities give an added advantage as the rays incident upon the bottom are more oblique, and thus dimming occurs at smaller offsets than determined from assuming a direct raypath. Processing is in general kept to a minimum to ensure that inherent amplitude variations are not distorted prior to the amplitude analysis. The essential steps in the sequence for the pre-stack analysis consist of the usual bandpass filtering, spherical divergence, deconvolution, sorting to common-midpoint gathers and normal moveout correction, wavelet shaping, modelling and AVO. The AVD effect appears prominent enough to satisfactorily detect fractures (Figures 4 & 5).

Discussion and conclusions

The AVD method provides the ability to access sub-seismic fractures using seismic anisotropy in the offshore environment. The method also has potential to resolve difficulties with time-lapse acquisition. However, as with all new technologies there are issues yet to be addressed, to improve the robustness of the technique. In particular, as the effect is observed at large offsets, the amplitudes require more careful processing and interpretation. The amplitude variation is therefore less pronounced than for post-stack shear-wave sections and more susceptible to lateral heterogeneity. The areas highlighted for improvement or further understanding include:

1) the role of structural variation;

2) fluid flow within the reservoir, and how it may enhance AVD, and induce attenuation and frequency dependence (MacBeth 1998);

3) the best procedure for determining a stable calibration horizon;

4) the value of other phenomena such as azimuthal variation in moveout (Li 1997) and local shear wave conversions.

Acknowledgements

The offshore example work was funded by the OSO/NERC Hydrocarbon Reservoirs LINK programme and Amerada Hess, and the AVD programme by the sponsors of the Edinburgh Anisotropy Project: Amerada Hess, Amoco, BG plc, Conoco, Elf, Fina, Mobil, PGS, Phillips, Saga Petroleum, Schlumberger, Shell, Texaco. The material is presented with approval from all project partners and the Director of the British Geological Survey.

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AVD for fracture detection


Figure 4. Gather taken from the lines in Figure 2, which display dimming symptomatic of the oil-filled fractures. Note the dimming for the bottom-chalk event in lines A2 and W (perpendicular to the fracture strike).
Figure 5. Averaged amplitudes for near and far-offsets along the lines in Figure 2. The lower diagram shows the expected dimming at far-offsets only within the oil-filled fracture zone.