Introduction to this special section: Practical applications of anisotropy

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The use of seismic anisotropy is a topic that has evolved dramatically in the last 25 years in the oil and gas industry. Even though physicists who study waves and vibrations in solids have taught us that elastic properties of rocks should be described by a complex set of functions and parameters, many years of seismic data processing were conducted assuming that the velocities in the subsurface rocks were isotropic, *and* that the shear modulus was zero (that the rocks could be treated as "a liquid"). "Isotropic" means that the value measured (e.g., velocity) is the same in all directions (whether you consider angles of incidence or source-receiver azimuths) for a rock volume of interest.

Keeping in mind that our industry has junior members who are wishing to learn as they go, this introduction starts with the definition of anisotropy as "the value measured depends upon the direction in which you make the measurement." Don Winterstein, formerly of Chevron Research, correctly stated in his numerous presentations and publications that *all anisotropy arises from ordered heterogeneity much smaller than the wavelength.*

The term "seismic anisotropy" is treated all too often as a kitchen sink, into which many different items are thrown, without specifying precisely what one is talking about. There are at least *three* types of anisotropy which must be distinguished between. Figure 1 illustrates these concepts. The most important seismic anisotropy is the layer anisotropy, arising from the layered sedimentary rocks, especially the shales, with their flat-lying internal-ordered heterogeneities, particularly the shale's clay platelets. The P-wave velocity horizontal is greater than the P-wave velocity vertical. Prestack depth migrations continue to struggle with the consequence of this: the imaging velocity for the far offsets is not the correct velocity for the vertical raypaths (that is, the raypath that ties the well depths). The symmetry associated with this order in the heterogeneities smaller than the wavelength is transverse isotropy with a vertical axis of symmetry (VTI). The largest measurements of VTI anisotropy in P-P reflection seismic reported so far in the literature has been 40% in offshore West Africa sediments (shales). Layer anisotropy has a larger effect on S-wave propagation than on P-wave propagation.

The second most important anisotropy is the azimuthal anisotropy, present wherever there are unequal horizontal stresses and/or vertical aligned micro- or macrofractures. Azimuthal anisotropy is known in the presence of the split shear waves vertically propagating with their two different velocities being orthogonally polarized. The fast shear wave is polarized in the stiff direction (parallel to the maximum horizontal stress and/or the vertical aligned fractures); the slow shear wave is polarized in the compliant direction (the weak direction). In 1986, Willis et al. reported on shear-wave experiments across North America by an Amoco research party: in the 14 sites across North America surveyed for shear-wave birefringence (shear-wave splitting), 12 of the 14 had exhibited an average 2% shear wave splitting, (VSfast-VSslow)/VSslow. The shear-wave splitting magnitudes ranged from 1–3%. The presence of unequal horizontal stresses, and the resulting stress-aligned vertical microcracks, is interpreted as causing this shear-wave birefringence across the North American craton (in the sampled areas). Thus, there is a "background" effect, which we are often not interested in, compared to our interest in the reservoir section. A fractured reservoir may exhibit 10–15% shear-wave splitting for liquid-filled fractures and 18–25% for gas-filled fractures. ION Geophysical, which has processed many 3D P-P azimuthal data sets, recently stated that, across North America, a 3% azimuthal variation in P-P NMO is commonly observed, when the far offset is equal to or greater than reflector depth. The cause of the 3% azimuthal variation in the P-P NMO is interpreted as unequal horizontal stresses, because vertical aligned macrofractures that flow fluids are not everywhere; they are only occasionally or rarely present.

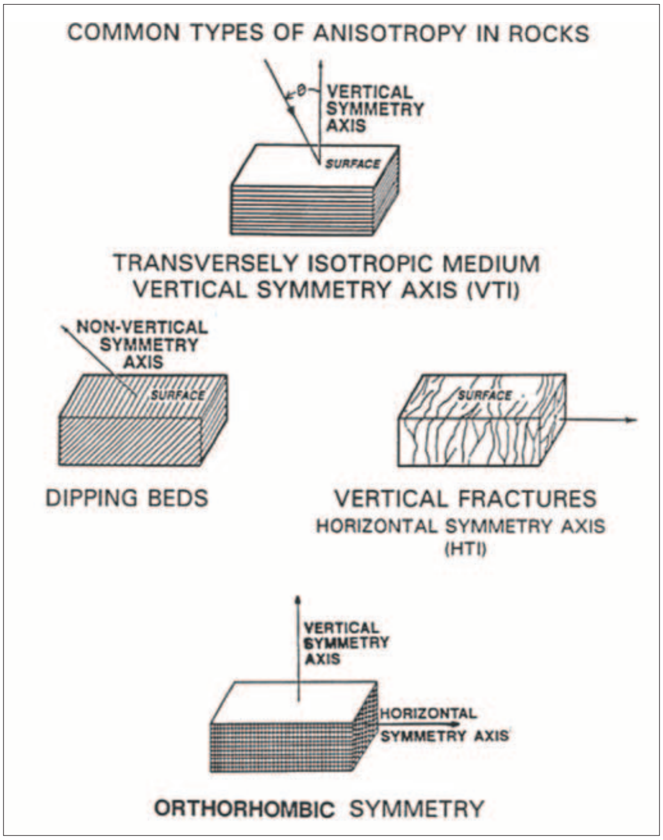

Figure 1. *Examples of types of anisotropy (from Tatham and McCormack, 1988).*

Unequal horizontal stresses, on the other hand, are known to be widely present throughout the upper 40 km of the crust (see the World Stress Map, Figure 2). The azimuth of the maximum horizontal stress is a prediction of the fast P-wave velocity direction, and the polarization of the vertically propagating fast shear wave. But, oil companies work at a much finer spatial scale than this map! The consequence of inequality in the horizontal stresses is an expectation that the P-P NMO velocities will vary by azimuth, for offsets approximately equal to target depth. The variation of P-P NMO velocities by azimuth is *signal* (pertaining to the stiff direction of the rock, and the inequality of the horizontal stresses) not *noise*. The first paper in this special section, by Jenner, provides a useful workflow for extracting this important information.

The symmetry associated with the presence of one set of vertical aligned fractures is mathematically termed transverse isotropy with a horizontal axis of symmetry (HTI). HTI fails to include the velocity effects arising from the layered nature of the sedimentary rock. Examples of processing in VTI and HTI media are presented in this special section. The near-surface unconsolidated sediments have been documented not only as azimuthally anisotropic, but also of large magnitude anisotropy (Cary et al., 2010; Lynn, 1991). "The more compliant a medium is, the more sensitive it is to shear-wave splitting due to nonisotropic stresses" (Cary et al.).

Orthorhombic (or orthotropic) is the minimum symmetry appropriate for the flat-layered rocks that contain unequal horizontal stresses and/or vertical aligned fractures (wherein the three stresses are one truly vertical, and two truly in the horizontal plane). In the presence of dipping layers and/or dipping fractures, other more complicated symmetries arise. Our industry has seen the imaging of dipping reflectors in the offshore Gulf of Mexico, using tilted TI (tilted layers, TTI) imaging algorithms, wherein the migration velocity increases as a function of angle off the normal to the dipping plane. It is likely that tilted orthorhombic will likewise become of interest, as well as monoclinic, wherein one of the 90° angles between the three axes becomes non-90°.

Jon Claerbout stated in his classic 1985 book *Imaging the Earth's Interior*: "Mathematically the Earth is treated as if all were a liquid or a gas." During the early years of processing, the rocks were treated as though the shear modulus was zero (that is, "as water") but lots of oil was found under this assumption. However, costly mistakes also started to be more common as time went by.

Various reasons explain why the isotropic assumption was a good one in the early days. Most data consisted of 2D, compressional P-waves recorded using relatively short arrays. 3D data acquisition was in its infancy and shear waves were rarely recorded. As 3D acquisition improved and the recording of longer offsets and wider azimuths became both technically and economically feasible, it also became clear that the isotropic assumption was no longer a good one to explain variations observed in these wave-phenomena-rich data sets. In the vertical seismic profile (VSP) world, however, practitioners had already realized that shear-wave splitting was a common observation and they started talking about anisotropy years before their colleagues in the surface seismic world did. VSPs are routinely recorded with three-component receivers and comprise the richest of all seismic data sets to mine for information on shear-wave velocities and azimuthal anisotropy.

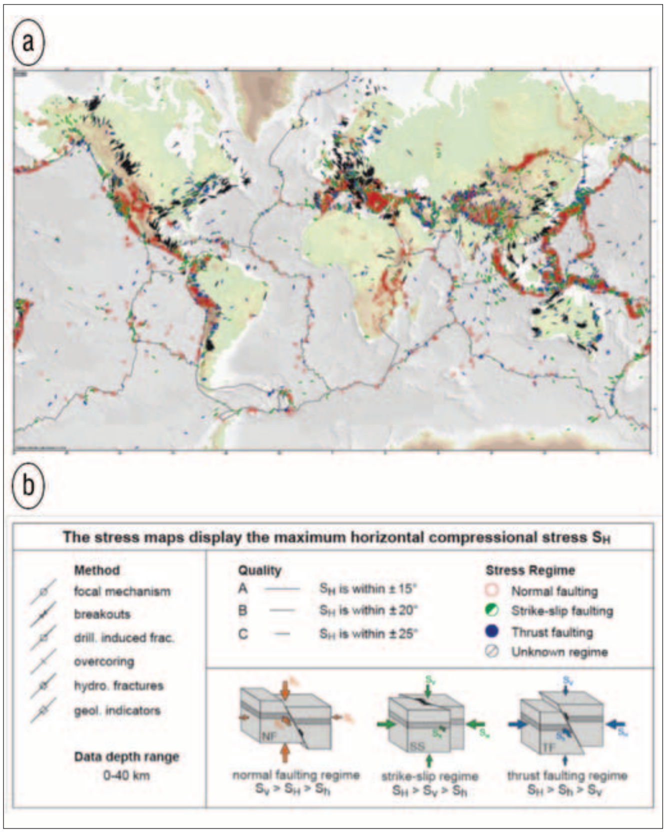

Figure 2. *(a) World Stress Map, release 2008, a project of the Heidelberg Academy of Science and Humanities (Heidbach et al., 2008). The vectors point in the azimuth of the maximum horizontal stress, as measured somewhere in the top 40 km of the Earth's crust. Plate tectonic movements are usually identified as the driving mechanism causing the unequal horizontal stresses in the upper crust. The color indicates the stress regime: red = normal faulting, green = strike slip faulting, blue = thrust faulting, black = unknown regime. For more information, go to* www.world-stress-map.org. *(b) Legend of the World Stress Map.*

The use of seismic anisotropy has passed through various stages in the oil and gas industry. From a curiosity that took place only in academic circles, to the reason to explain any inconsistency observed in the data (regardless of whether it was related to anisotropy or not!), our understanding of anisotropy has evolved to the only way to solve many problems and explain numerous observations in the data, and to a concept that can help separate rocks (lithology) from geological conditions (stress and/or natural fractures) in the reservoir. Today, anisotropy has become a standard practice in the industry even though researchers and practitioners still have numerous challenges ahead. In each play, the interpretation of surface seismic-reflection anisotropy must be tied to borehole measurements such as borehole ovality, crossed dipole shear-wave sonics, cores, wireline logs, image logs, VSPs, production data, etc.

This special section presents six field data examples where the use of anisotropy was crucial to solve a data processing problem or to add insights about the subsurface that are not possible to add if we still assume that the rocks behave like liquids.

The first three papers of this special issue deal with different aspects of data processing of long offset, wide-azimuth 3D P-P seismic data. The first paper by Jenner describes a workflow that can be used to incorporate both long-offset nonhyperbolic traveltimes related to VTI anisotropy and azimuthally varying traveltime variations related to HTI anisotropy into a prestack time migration. This workflow separates the VTI and HTI components so that instabilities in estimating VTI parameters do not impact HTI parameter estimation. Application of this workflow to field data shows that the inversion produced aligned gathers and improved prestack time migrations in the presence of both nonhyperbolic moveout and azimuthal velocity variation. The industry's ability to interpret azimuthal anisotropy is only as good as the processing contractor's ability to identify and separate out the VTI effects.

The second paper, by Burnstad and Keho, presents a new premigration target-oriented stratigraphic processing flow which prepares wide-azimuth, long-offset, 3D P-P seismic data for azimuthal amplitude variation with offset and azimuth (AVOAZ) analysis. This procedure adapts the multichannel, surface-consistent concepts developed for AVO processing, to include azimuth. They demonstrate this new approach on field data from a 3D survey acquired over two carbonate oil reservoirs in Saudi Arabia.

In the final data-processing-related paper, Liu et al. propose a workflow and method to mitigate overburden effects before using P-P AVOAZ analysis to extract geologically meaningful fracture distributions at reservoir levels. They conclude that seismic-anisotropy attributes extracted at reservoirs may be strongly affected by the acquisition footprint and shallow geological features whose effects need to be minimized before interpreting fracture-related attributes with the help of other geophysical and geological data.

Sena et al. present an integrated seismic approach based on prestack azimuthal P-P seismic data analysis and well-log information to identify sweet spots, estimate geomechanical properties, and in-situ principal stresses in resource shale plays. They confirm that, in this kind of play, properties such as Young's modulus and Poisson's ratio provide valuable information for facies identification, mineral content, and rock strength. Additionally, they show how analysis of differential horizontal stress was used to calibrate anisotropy observations from seismic data yielding stress field predictions such as fracture initiation pressure and closure pressure. Their workflow is illustrated with a field data example.

The last two papers highlight the importance of considering anisotropy during microseismic processing. Van Dok et al. show that inclusion of both VTI and HTI seismic velocity anisotropy is necessary to correctly locate microseismic events associated with hydraulic fracture stimulation. The purpose of the paper is to discuss some fundamental elements of why HTI and VTI affect correct location of microseismic image points and show a field data example of how the isotropic assumption can lead to dramatically wrong answers.

Eisner et al. show that microseismic events observed on surface arrays allow determination of the orientation of the symmetry axis of the anisotropy; VTI anisotropy appears to dominate in the shale reservoirs they have studied. They also show that permanent buried arrays offer a unique opportunity to estimate anisotropy owing to the consistency of the receiver response over long periods of time and multiple well treatments. The inverted anisotropic parameters can complement active seismic imaging programs and improve imaging of the target reservoirs.

We, the editors of this special section, also thank the two other authors who also prepared and submitted world-class articles on the use of azimuthal anisotropy in 3D field seismic data for fractured reservoir characterization, only to have their management refuse permission to publish. Really outstanding work is going on all around the world!

Unlike other geophysical technologies that may come and go, seismic anisotropy is a fundamental phenomenon that affects the propagation of all body waves in rocks, and geophysicists continue to document its importance in the industrial world. We hope that these papers will serve to illustrate the benefits of acquiring, processing, and interpreting the anisotropy at depth. TLE

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