

Gaining Insight Into Formation Anisotropy Using Full Azimuth Imaging And Analysis Tools

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The search for ways of reducing the amount of repetitive work while reducing project turnaround times is a constant activity in oil and gas exploration/production industry. With the constraints imposed by the relatively short time between obtaining a permit and having to drill a first well, and the constant growth of the data volumes that need to be processed, interpreted and analysed prior to committing to spud, technology is the best investment to buy more time for data review, analysis and prospect ranking.

Seismic processing is time-consuming. The rate at which computer processing speeds increase, following the famous Moore's law (computer processing power doubles every 18 to 20 months), has not dramatically shortened the turnaround of projects, because data acquisition density, recording lengths, higher data precision, more complex algorithms and other improvements to the processing and imaging process have been making similarly larger and larger demands on the performance of the computers they run on. Another factor that has inhibited the acceleration of project throughput have been some labour-intensive tasks that seemed incompressible. Velocity picking and analysis is one such a component in the seismic data processing workflow. It is probably the most complex and human-intensive part of the whole process.

So, it is logical that for a number of years there has been a search for a robust and reliable automatic velocity picking process, as it can replace this long and tedious procedure with an automated one. Such a capability was recently made available commercially, and is already in use in production processing centers around the globe. The algorithm involves the usage of amplitude versus angle (AVA) techniques and measurements in order to perform a detailed automatic residual moveout/velocity analysis in a robust and effective way.

Today, 3D seismic data contains by default a diversity of azimuths for rays travelling from shot to receiver. In marine acquisition, the array of airguns shooting into 12 or more streamers generates a lot of recordings that have azimuths at a strong angle from the heading of the acquisition vessel. Onshore, wide swathes of both vibrator crews and geophone lines make for a very diverse spread of azimuths for shot-receiver pairs. By design, modern datasets are being acquired with richer and wider azimuths. Such acquisitions have been found to be highly desirable for fractured reservoir or stress analysis, as fractures or stress can produce measurable differences in velocity as a function of azimuth. This velocity dependency on azimuth is referred to as anisotropy, and in the presence of vertically aligned fractures or stress direction is referred to as anisotropy of the HTI type (or horizontal axis of symmetry).

Because these velocity differences (moveouts) are detectable with the seismic method, the goal is to capture those differences by evaluating multi-azimuth or even full azimuth angle gathers. In other words, rich azimuth data, whether by planning or simply due to the acquisition's inherent geometry, captures these anisotropic effects and provides a means to determine fracture orientation and density or stress direction and intensity.

Since anisotropic velocities are the basic seismic signatures of fractured reservoir characterisation, accurate anisotropic velocity analysis is a critical step when processing rich azimuth data. Anisotropic velocity differences (moveouts) can be used directly in inversion processes to determine the properties of fractured or stressed reservoirs, or they may be used as a preconditioning step for amplitude versus angle versus azimuth (AVAZ) analysis which requires 'flattened' data. Once flattened, (AVAZ) inversion schemes can also be applied to determine fractured or stressed reservoir properties.

There are two ways to deal with the rich and wide azimuthal data that is being acquired today in both offshore and onshore environments. The conventional approach is to separate the seismic data into a number of azimuth sectors (typically eight) and process each data sector independently. This means that the velocity for each dataset is picked independently from the other sectors. Consequently, velocity picking must be performed multiple times, and there is no consistency in the picking procedures between the different datasets. This method is therefore very time consuming, as well as requiring large amounts of machine time to process. Although anisotropic residual velocity analysis can facilitate the analysis of these sectorized gathers,

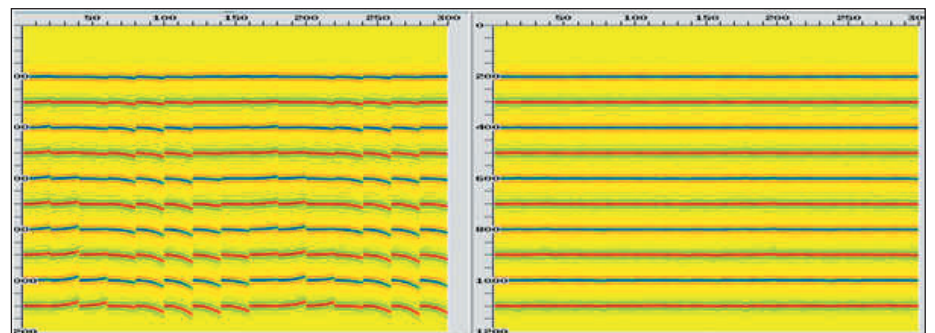


Fig. 1. Synthetic gather with continuous azimuthal component: a) Input gather with noticeable moveout variations with azimuth; b) Gather flattening with the automatic residual moveout operations of FastVel.

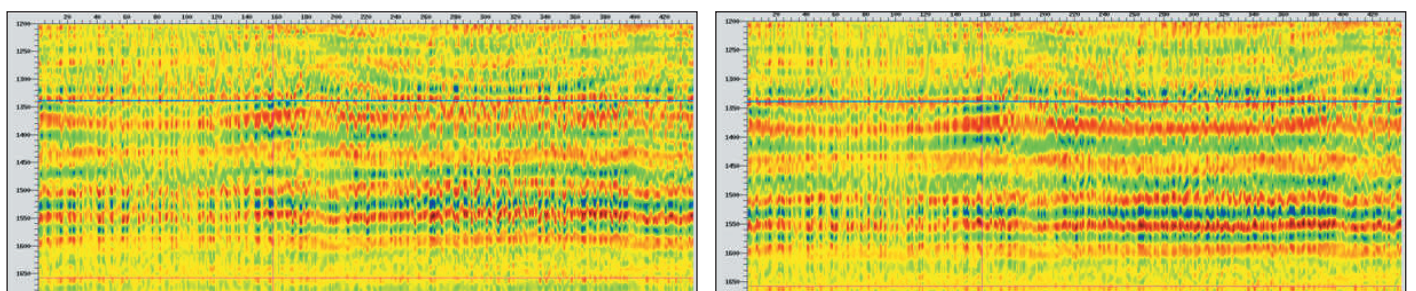


Fig. 2a. Real data example, with visible moveout variations as a function of reflection angle and azimuth. Angle and azimuth are repeated throughout the gather. Fig. 2b. Same gather flattened by anisotropic FastVel.

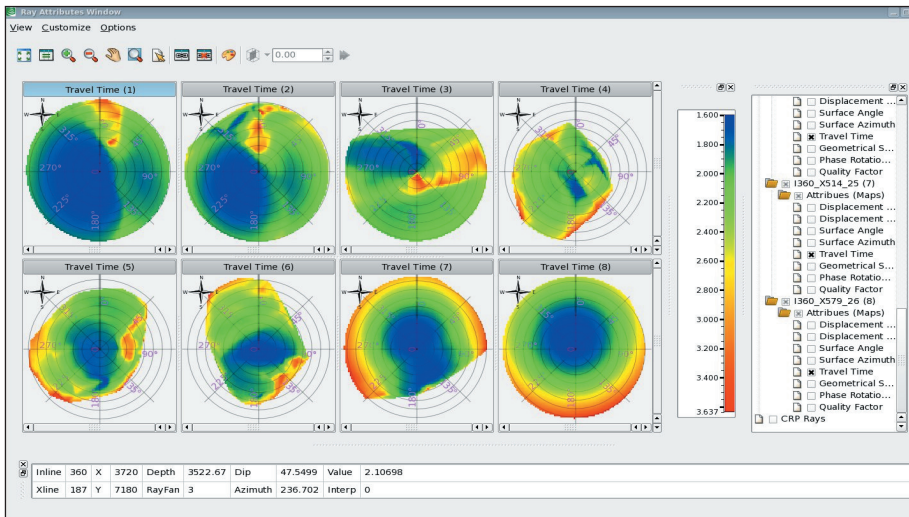


Fig. 3a) Ray attribute display capturing travel times as a function of subsurface azimuth and angle at eight different subsurface locations.

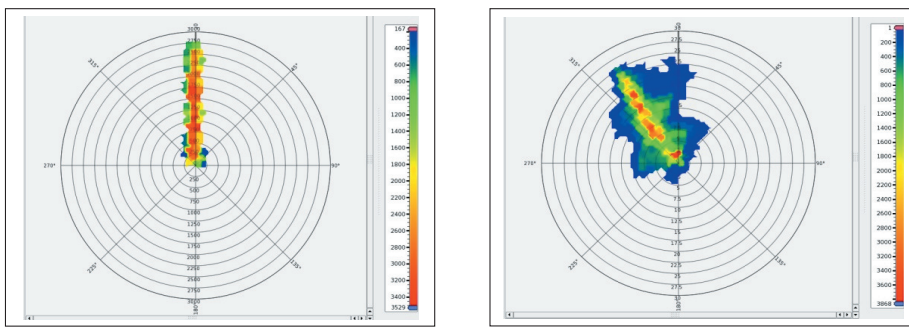


Fig. 3b) Surface azimuth and corresponding subsurface azimuthal coverage for a target subsurface point. The lack of correlation between the two reflects the complexity of the overburden.

a preferred approach creates full azimuth angle gathers in depth, using a rich decomposition procedure (EarthStudy 360™) designed to preserve all subsurface azimuths. Here velocity picking is done once, and the resulting velocity field is sampled over all subsurface azimuths. Naturally, the preferred workflow goes directly from field recordings to full azimuthal gathers—however, the automatic residual moveout operation (FastVel) can also operate seamlessly in one step on multiple sectorized gathers. Anisotropic FastVel provides either a second or fourth order high resolution velocity field in both time and depth. Note that the fractures impose high frequency variations on the velocity field, and therefore a high 'directional' resolution procedure is a basic requirement for fractured reservoir analysis.

Figure 1a) shows a synthetic example of a migrated full azimuth 3D depth angle gather. This is a 3D gather unfolded so azimuth varies in the horizontal direction. There are approximately 1,000 traces in each migrated gather, densely sampling the azimuth axis and the reflection angle axis. Figure 1b shows the results of the automatic residual moveout process operating across all azimuths. Figure 2a) shows a similar real data gather. Note the non-flatness of the gather which has two components. One is a moveout error which is a function of the reflection angle, and the other describes the moveout variations with azimuth. The objective is to flatten these

gathers so that they can be used as input data for amplitude versus angle versus azimuth inversion schemes. Figures 1b) and 2b) show the corresponding flattened gathers, demonstrating the power of this procedure. Note that the flattening is achieved by fitting a 2D hyperbolic moveout surface to the seismic amplitudes in the gather, similar to the conventional 2D velocity analysis. The two parameters that describe each hyperbolic surface are the output of the procedure, and are used to describe the two components of the velocity field required to 'flatten' the gather.

This may come across as a search for excessive detail; after all, it could be argued that for many years our industry has prospered deriving seismic velocities strictly based on surface acquisition parameters of offset and one azimuth. Work in the full azimuth and angle domain has proven, however, to reduce the uncertainty in our velocity models, increase the accuracy of our seismic images, and improve the characterisation of our reservoirs. By properly handling the mapping of surface-recorded, shot-receiver pairs to subsurface angles and azimuths, it is also possible to identify areas in the subsurface that are receiving poor or unequal illumination. This provides valuable information towards the level of credibility one can assign to events that show up on the final migrated data volume. In particular, around strong disturbances such

as salt domes being able to add an azimuth component makes it possible to understand how events in close proximity to the rim of the dome may be illuminated from only some directions, while being unreachable from others. Other articles cover in more detail the impact of full-azimuth, angle domain target-oriented imaging processes (Dopkin and Koren, 2009), the point of interest for the interpreter is the availability of information for a given reflector that can be readily understood and assessed for the purpose of assigning a reliability criteria to them.

This analysis is made possible by two complementary displays designed to capture the dependency of the seismic image on the velocity model and seismic acquisition used to create it. Full azimuth angle domain ray tracing is used to generate the information in these displays. This rich ray tracing procedure is performed from the subsurface to the surface, taking into account the structural information present in the model. The first display (Figure 3a) shows the travel times resulting from the ray tracing for all incident angles and all azimuths at eight different subsurface locations. In complex overburden situations, the graph will not be entirely populated, and the blank areas will provide the interpreter with indications of areas of poor subsurface illumination.

The second display (Figure 3b) compares the surface offset azimuth (the azimuth of a shot-receiver record) with the corresponding subsurface azimuth of an image point target level. In a relatively homogeneous overburden and velocity environment the two azimuth directions will be quite close to each other. In geological settings where the ray paths are strongly distorted, for example by salt domes, we will observe that there can be considerable differences between the azimuth values. This example emphasises the need to avoid azimuthal sectoring and instead use decomposition procedures that make use of full subsurface azimuthal information.

These tools, be it automated velocity correction or interpretation support features like full azimuth illumination, open a whole new area of activity for geophysical and interpretation experts. There is definitely a need for these activities to come closer together, as the imaging process becomes richer in interpretative tasks, and the interpretation activity now has an open window on the subsurface models that have been built in order to generate the post-stack data, and the illumination issues that may be misleading the interpreter.

Reference

Dopkin, D. and Koren, Z. (2009). Seismic Wave Field Decomposition Both Qualifies and Quantifies Velocity Modeling, 3-D Imaging, July 2009. p. 107-115. ■