# Untangling Acoustic Anisotropy

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## ABSTRACT

Acoustic anisotropy analysis is used in a wide variety of applications, such as fracture characterisation, wellbore stability, production enhancement, and geosteering. However, the methods by which acoustic anisotropy are determined are not always well understood, both by the end user and the data analyst. Azimuthal variations in velocities may be due to stress variations, intrinsic anisotropy, bed boundaries, or some combination thereof. Environmental effects such as hole inclination, centralization, wellbore condition, dispersion and source/receiver matching affect the viability of the data and must be considered in the interpretation. Untangling the various acoustic anisotropy factors is essential to effectively interpreting the results.

This paper begins with a discussion of the types of acoustic anisotropy, followed by a review of common industry methods for extracting anisotropy from wireline and LWD azimuthal sonic data. Environmental factors such as tool centralization, irregular borehole shape, poor tool calibration, and dispersion are considered, paying particular attention to the practical limitations of acquiring data suitable for high quality anisotropy analysis in adverse conditions.

Quality control techniques are discussed in some detail, as there are various causes of "false anisotropy" that should be recognized so as not to incorrectly interpret processing artefacts as formation features. Quality control plots are suggested to aid the non-specialist in determining whether the anisotropy results are viable.

Intrinsic, induced, and geometric anisotropy are discussed in detail, along with consideration of the depth if sensitivity of acoustic measurements. Finally, a case study is presented to illustrate the art of untangling overlapping acoustic anisotropy responses.

## INTRODUCTION

Acoustic anisotropy is essential in a number of applications, most notably in seismic integration, wellbore stability and production optimization. However, the complex physics of acquiring and processing acoustic anisotropy data along with the frequent interlacing of multiple types of anisotropy must be clearly understood to effectively interpret the data. Thus, we begin with a review of the types of acoustic anisotropy (and the mechanism that cause them) along with the measurement principles behind optimally acquiring and processing the data. Following that, we consider visualization and quality control methods which should enable those who aren't acoustics specialist to easily determine whether the processed data are valid for use in application or if "false anisotropy" due to environmental, tool, or processing effects is present. Finally, we discuss how to untangle multiple anisotropy effects and present a case study.

## REVIEW OF THE TYPES OF ACOUSTIC ANISOTROPY AND THEIR APPLICATIONS

Acoustic anisotropy refers to a directional variation in velocities. The two primary geological factors that cause anisotropy are depositional (layering) which is referred to as intrinsic anisotropy and tectonic effects such as faults and fractures, known as stress anisotropy. In addition to geological factors, borehole acoustics measurements are sensitive to near wellbore variations due to the stresses related to the presence of the borehole. Azimuthal variations in velocities are also observed as the wellbore trajectory transects beds. This latter form we will refer to as geometric anisotropy. YYY

In seismic and borehole acoustics, there are several terms used to describe anisotropy:

VTI/TIV – Vertical transverse isotropy, meaning that velocities vary horizontally (but not vertically)

HTI/TIH – Horizontal transverse isotropy, meaning velocities vary vertically (but not horizontally)

TTI – Tilted transverse isotropy, meaning the axis of symmetry is neither parallel nor perpendicular.

Of course, in reality these are simplifications of the actual formations, as we rarely find materials which are truly isotropic in any direction, so we should consider these terms merely to mean that the anisotropy is predominately in one axis, with lesser variations in the other directions.

Confusingly, the terminology is generally taken to mean different things in the seismic and borehole sonic practices. In seismic terms, the axis of reference is always that of the earth. In borehole acoustics, the reference axis is taken as the borehole axis. If a well is drilled vertically, then the terminology coincides. Thus VTI would be a vertical wellbore penetrating horizontally layered formations and HTI would be a vertical wellbore penetrating vertically varying formations (such as in the case of fractures parallel to the wellbore). However, in a horizontal wellbore, borehole acoustics terminology differs from seismic – a VTI formation in a horizontal well is one whose axis of symmetry is parallel to the borehole, such as would be the case in vertically propagating fractures and a horizontal well. An HTI example would then be a horizontal wellbore through a depositional layered formation. **Figure 1** illustrates the terminology used in borehole acoustics.

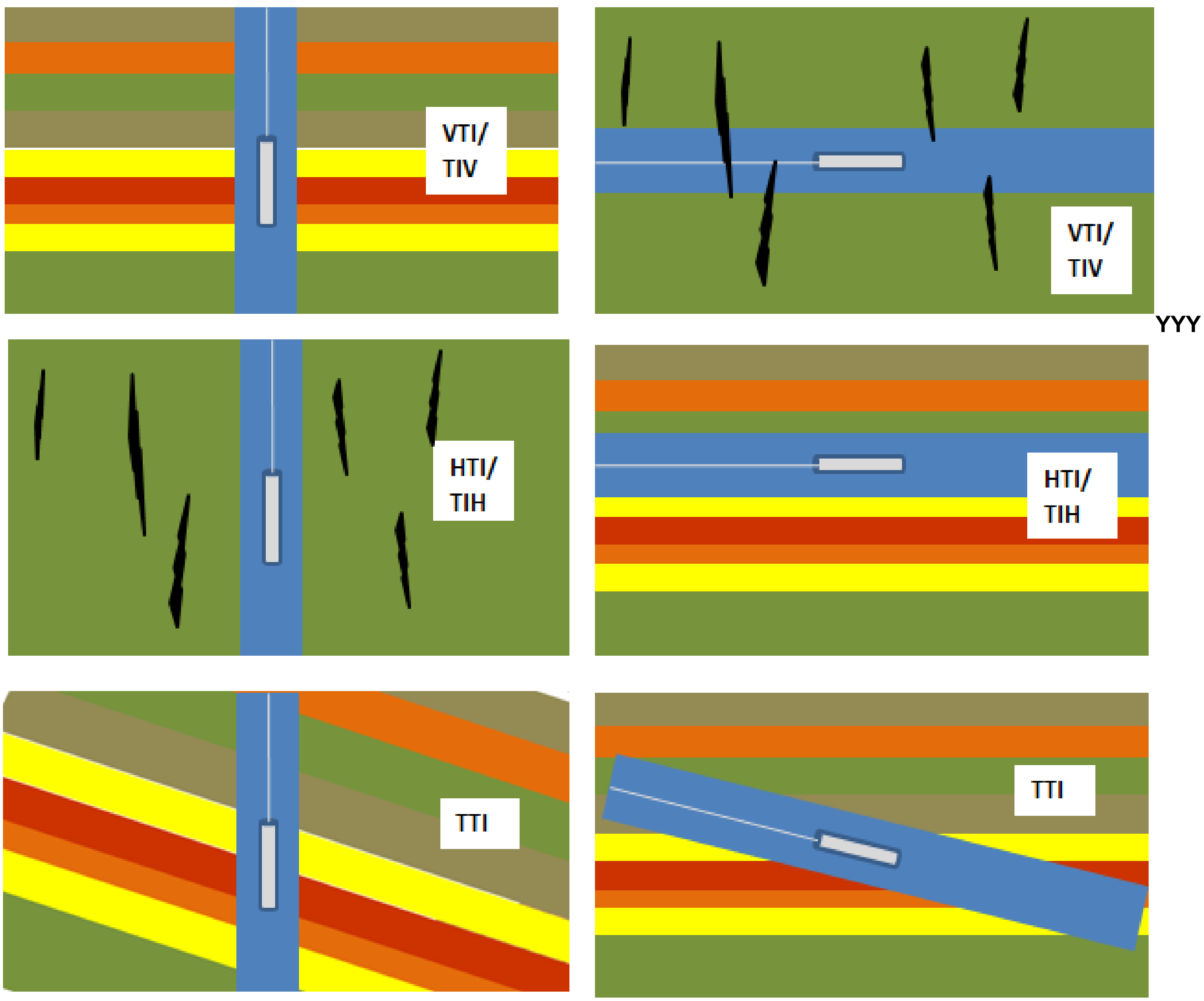


***Figure 1****: Illustration of different types of anisotropy, referenced to the wellbore trajectory.*

## ANISOTROPIC CONSIDERATIONS OF COMMON BOREHOLE MODES

Before we delve into how sonic tools measure anisotropy, we should first consider the azimuthal nature of sonic waves.

- *Compressional* (or p-wave) particle motion is parallel to the wellbore. Compressional velocities are influenced by stress or intrinsic anisotropy but will not show variations in the azimuthal measured velocities in a single well. For example, if we drill wellbores at different inclination through a naturally anisotropic formation, the velocities will differ if there is anisotropy (Hornby, 2003), usually with higher inclination wells observing faster velocities (if the z-axis stress is maximum). However, in the case of geometric anisotropy (transecting or approaching beds), the compressional wave can measure variations in velocity around the wellbore (Market et al, 2008). Compressional waves can be excited by unipole, monopole, dipole, and quadrupole sources. The directionality of compressional waves for geometric anisotropy calculations is dependent upon the source/receiver configuration. In general, focused sources like unipoles and dipoles allow for better azimuthal resolution than omnidirectional type monopole sources or quadrupole transmitters (Market et al, 2008, Wang et al, 2011).
- *Shear* wave particle motion is perpendicular to the wellbore and polarizes in the presences of stress or intrinsic anisotropy. In addition, shear waves are sensitive to geometric anisotropy. “Refracted” shear (sometimes known as direct shear or the pseudo-Rayleigh wave) can be measured when the formation shear velocity is faster than the mud velocity. Refracted shear waves can be generated by unipole and monopole sources as well as by higher order sources. Like compressional waves, refracted shear azimuthal resolution varies with the source configuration.
- *Flexural* waves are generated by a dipole source and are useful because they travel at velocities close to the shear velocity at low frequency (in the wireline environment), are present whether the shear is faster or slower than the fluid velocity, and are suitably directional for anisotropy analysis. Particle motion is perpendicular to the axis of the wellbore and thus flexural waves are ideal for measuring HTI anisotropy. With LWD tools, the presence of the drill collar means that the flexural wave does not converge to shear velocities at low frequencies (as is the wireline case), but at higher frequencies the LWD flexural wave can be used to estimate shear (Market, 2006). While the uncertainty in the shear estimate is greater than in the wireline case, it still can be useful as the flexural waves are still sensitive to azimuthal variations and can be used to determine shear velocities in slow formations.
- *Stoneley* (or tube) waves travel along the interface between the borehole fluid and the formation and particle motion is parallel to the axis of the wellbore. While Stoneley wave velocities are not as closely coupled to shear wave velocities as in the dipole case, they can be used to estimate the shear wave velocity parallel to the axis of the tool, complementing the flexural waves, which are sensitive to velocity variations perpendicular to the wellbore.
- *Screw* (quadrupole) waves are primarily of interest in the LWD environment and are of interest as a method to estimating shear velocities in slow formations. They are less affected by the presence of the drill collar and can give more accurate estimates of the shear velocity. However, they are not as azimuthally sensitive as dipole waves.

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## AZIMUTHAL DATA ACQUISITION

There are several types of azimuthal data acquisition used by commercial sonic tools. The azimuthal capabilities are determined primarily by the source and receiver configurations, along with the rotational behaviour of the tool. Simply put, the more sources that are fired simultaneously, the lower the azimuthal resolution. Likewise, the more azimuthal receivers that are summed together, the lower the azimuthal resolution.

*Source:*

The source configuration is influential in the azimuthal sensitivity of sonic measurements because it determines which modes will be excited and the azimuthal span of the wellbore that is excited by the source (**Table 1)**. However, we must consider the source and receiver configuration together to fully understand the azimuthal response.

| ***Source Type*** | ***Excitation Modes:*** | |
|---|---|---|
| | *Primary* | *Secondary* |
| *Unipole* | Compressional Shear | Stoneley |
| *Monopole (ring-around-collar)* | Compressional Shear | ~ |
| *Dipole* | Flexural | DTC DTRS |
| *Quadrupole* | Screw | DTC DTRS |

***Table 1****: Modes excited by each source configurationand their azimuthal sensitivity*

*Receivers:*

Receivers can be configured as single- or multiple-azimuthal arrays. Single-azimuthal arrays have one array of receivers and will collect data and record waveforms in one azimuthal orientation. Multi-azimuthal arrays commonly have 2, 4, or 8 arrays of receivers. Some tools are designed to store the signal at each azimuthal array of receivers separately, while other multi-array tools acquire data at two or more azimuths, but sum (or subtract) the data downhole and no record of the individual waveforms is kept.. The most common form of this practice is wireline crossed-dipole tools, many of which have 4 arrays of receivers (A,B,C,D) but only store the subtracted data (XX=XA-XC, YY=YB-YD, XY=XB-XD and YX=YA-YC) for the dipole firings and the summed monopole results (MP=MA+MB+MC+MD). It is becoming more common to store all azimuthal receiver waveforms for advanced applications. Storing the individual azimuthal receiver allows for analysis of the waveforms at discrete azimuths and can lead to higher azimuthal resolution and makes it easier to distinguish non-symmetric events (like bed crossing) from intrinsic or stress anisotropy.

*Rotation:*

Wireline sonic tools acquire a single set of measurements at each depth. While the tool might rotate slowly over depth (as the cable unwinds), there is virtually no tool rotation during a sample (which takes less than 1 second) and very little between depth stations (e.g. 0.5 ft. or 0.1 metres). There are 3 options when considering azimuthal applications:

1) Collect crossed-dipole data and process using Alford rotation techniques
2) Design the tool with many azimuthal arrays of receivers in order to collect data at frequent azimuthal intervals around the tool (the maximum number of receiver arrays on any commercial tool today is 8)
3) Make multiple passes with the tool oriented at different azimuths.

LWD tools rotate as the drill string rotates. As the tool spins, it will acquire data at the angle at which it was oriented at the time the transmitter(s) fired. This means that in addition to the 3 methods above, the tool could be fired frequently at a single depth interval to acquire data at many azimuths. Of the commercially available azimuthal LWD tools, there are 3 main techniques for acquiring azimuthal data:

1. Fire the tool at even time intervals (e.g. every 100 milliseconds. Store all the waveforms. The benefits of this method are high azimuthal fidelity but the downside is that large amounts of data storage are required. (Market et al, 2011)
2. Fire the tool at even time intervals (e.g. every 100 milliseconds.) Bin the data such as is common practice with other LWD imaging tools. Stack the data within each bin and only store the stacked waveforms. This method requires less storage space but results in lower azimuthal fidelity than method 1. (Mickael et al., 2012)
3. Fire the tool at specific times (co-ordinated with the tool rotation) to acquire data at pre-defined locations. For example, instead of firing every 100 milliseconds, fire when the tool is at 0, 15, 30, 45, etc. degrees. This method is somewhat of a compromise between methods 1 and 2. The amount of data storage required depends upon the number of azimuths requested. The tool needn't fire as often (to acquire 16 azimuths of data) as the tool in number 2 would, but method 2 allows for data stacking and possibly increased signal-to-noise ratio.

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*Important considerations, azimuthal data acquisition:*

- Wireline sonic tools generally do not have on-board azimuthal tracking and must be run in conjunction with a navigation pack (and the alignment of the sonic tool to the navigation tool must be known). If the imaging tool and sonic tool are run together, the imaging tool's navigation may be used, so long as the azimuthal offset between the two tools is known.

- Azimuthal LWD tools generally track the azimuth with a magnetometer integrated into the sonic tool. Not all tools have this capability. It is generally not practical in the drilling environment (i.e. during rotation) to use the navigation data from another tool in the string to determine the azimuth of the sonic data. For example, the density tool may track the azimuth every 10 milliseconds, but to be able to use that data to determine where the sonic tool was oriented would require the clocks on both tools to be extremely well calibrated or linked, which is difficult in practice.
- In casing, magnetometer-based navigation systems are not valid, so whereas the tools may still be able to acquire data at multiple azimuths, we won't know the absolute orientation of the measurements. Gyros/accelerometer-based navigation devices may be used though the azimuthal resolution is generally lower.

## AZIMUTHAL DATA PROCESSING

Once we've acquired azimuthal waveform data, we should consider the various methods of processing the data.

*Azimuthal binning*: The most straight-forward processing technique applies when data are acquired at many azimuths, such as in the case of the rotational LWD data or as with a stationary tool having a large number of azimuthal receiver stations. For example, if we consider a tool which stores the data into 16 bins (**Figure 2**) we can process each bin of data to determine the compressional and shear velocities, then create an azimuthal image from the velocities. **Figure 3** shows an example of 16 semblance tracks (one for each azimuthal bin). **Figure 4** shows a 360 degree azimuthal image of the compressional using the slowness values picked from each bin in **Figure 3**.

This direct method can be used on any number of bins. It is possible in the geosteering environment to transmit quadrant data real-time, which can then be processed to determine the slownesses up, down, left, and right.

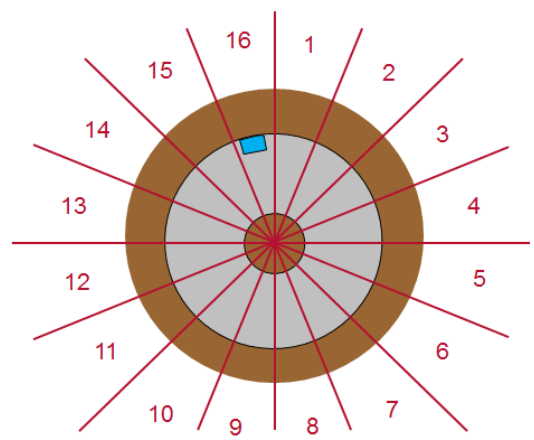


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***Figure 2****: Illustration of an LWD azimuthal binning scheme.*

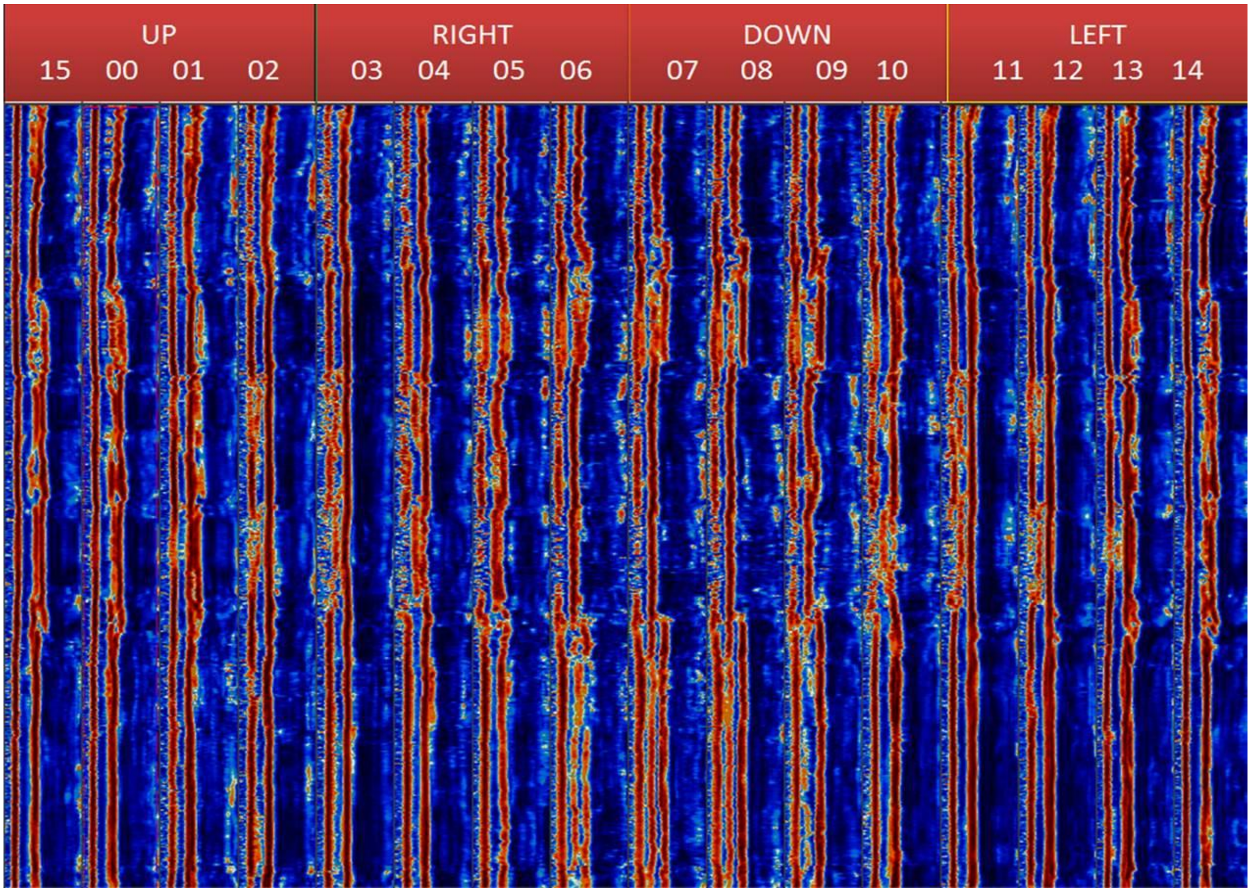


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***Figure 3***: *16 bin semblance maps. The compressional and shear slownesses can be picked from each bin, then combined to form azimuthal images such as in **Figure 4.***

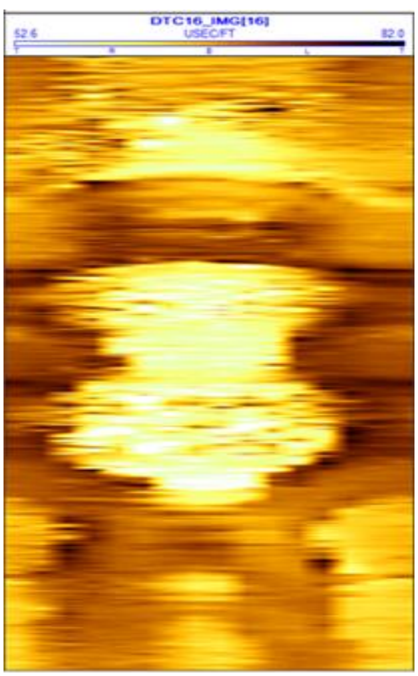


***Figure 4***: *Azimuthal image from 16-bin processing (Compressional Wave)*

*Alford Rotation Methods*

Alford rotation is commonly used with crossed-dipole data to calculate waveforms at all azimuths given XX, XY, YX, and YY waveforms acquired in crossed-dipole mode (Esmersoy, 1995). Once the waveforms are calculated at all azimuths, 3 techniques are commonly used to determine the minimum and maximum shear velocities and the direction of the fast shear.

1. Minimization of energy (Esmersoy, 1995)
2. Waveform Inversion (Blanch, 2002)
3. Azimuthal semblance

We should recall that Alford rotation exploits shear wave polarization while assuming hemispherical symmetry and a cylindrical wellbore. The quality of the results depends on how well the transmitters and receivers from each array are balanced in addition to how centralized the tool is in the wellbore. Alford rotation should be used with the following caveats in mind:

- It is not suitable for determining the compressional slowness at all azimuths (e.g. compressional waves don't split in the manner of shear waves, so in an intrinsic or stress-anisotropy environment, Alford rotation methods will not yield an azimuthal image of compressional slownesses).
- Will not work well in non-symmetrical cases such as a bed boundary crossing, inclusions, etc.
- Will be dominated by the strongest shear anisotropy. For example, if we are in a horizontal well in a strongly intrinsically anisotropy shale (i.e. 30%) and there is also a local stress perturbation which has an anisotropy of 10%, Alford rotation methods can have difficulty separating competing effects.

**Figure 5** is a log example showing a comparison of method 1 (minimization of energy) and 3 (azimuthal semblance). Track 4 shows and azimuthal differential slowness image, where red colours indicate slower than average (minimum stress) and blue colours indicate faster than average (maximum stress). The black dotted curve in track 4 is the fast shear azimuth determined by minimisation of energy methods. There is good agreement between the two methods and thus we have high confidence in the anisotropy results.

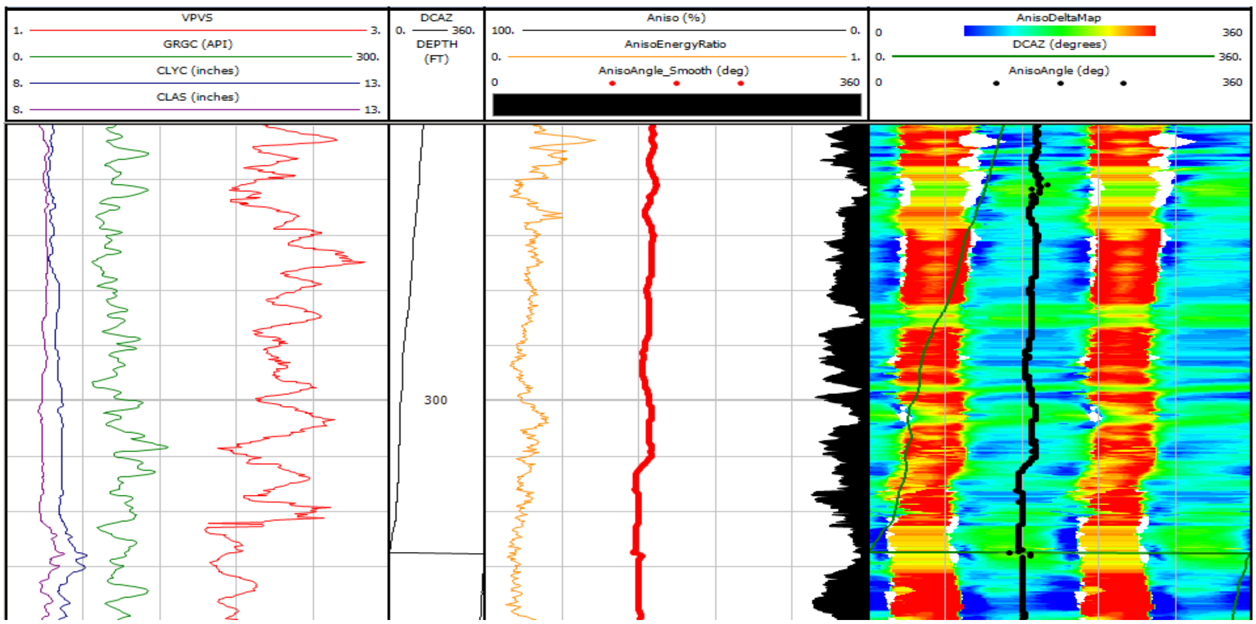


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**Figure 5:** *Log example comparing the results from cross-line minimisation (black curve, track 4) and azimuthal slowness (coloured image, track 4) anisotropy methods*

## UNTANGLING COMPETING ANISOTROPIC EFFECTS

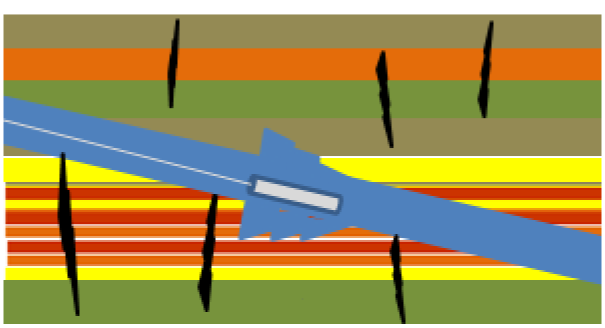

Figure 6: *Competing forms of anisotropy*

Untangling competing forms of anisotropy (**Figure 6**) requires us to first ensure that the azimuthal variations in log response are real formation effects (not environmental issues such as eccentred tools, unbalanced receivers, hole degradation, etc.), then to use all the data at our disposal. This may include details of the geology, well history, the world stress map database, other borehole logs and even cuttings.

Some questions to consider before beginning the azimuthal shear analysis include:

- Are the azimuthal variations in velocities formation responses or environmental effects?
- Is the anisotropy due to coarse layering?
- Is the anisotropy due to fine layering?
- Is the anisotropy due to fractures?
- Are the stress variations/fractures drilling induced or intrinsic?
- Is there more than one competing cause for the anisotropy?

*Formation response vs. environmental effects*

As a first step it is important to rule out environmental effects as the cause of any observed azimuthal velocity variations. Especially when relying upon Alford rotation to compute azimuthal responses, it is necessary to review the raw waveforms, checking the receivers and transmitters are balanced. The calliper should be plotted to see if it shows good hole conditions. Eccentricity of the tool in the hole can cause "false anisotropy", i.e. variations in azimuthal response that are due to tool position rather than formation effects. Stoneley contamination of flexural mode data can also lead to false anisotropy. Additionally, if the gains have been applied incorrectly in the processing, this can also lead to erroneous results. A clear indicator of false anisotropy due to tool or environmental effects is seen when the angle of the fast shear direction tracks the tool rotation. **Figure 7** shows an example of true and false anisotropy plotted in two ways:

1) The waveforms have been rotated (using the navigation curve) to be in the earth's frame of reference, then anisotropy has been calculated. In this case, we expect the fast azimuth curve to vary little over depth (within the same formation) while the tool's azimuthal position curve will move significantly (assuming the tool is allowed to swivel)
2) Anisotropy is computed in the tool's frame of reference (the tool's azimuthal position is accounted for in a later step). In this instance we expect the fast azimuth curve to track the tool's azimuth curve. If the fast azimuth curve is nearly constant despite the tool rotation, this is an indicator of false anisotropy.

It is recommended to allow the tool to rotate whenever possible to allow for this valuable QC method.

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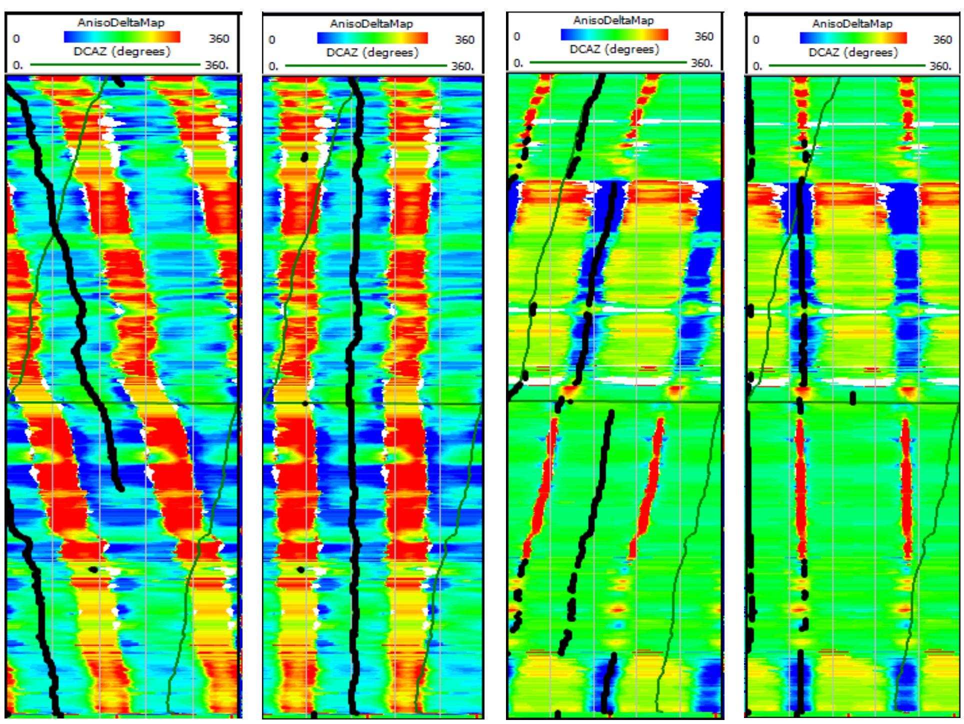


a b c d

**Figure 7:** *Quality control plots showing tool azimuth (DCAZ, in green) and fast azimuth (black) atop the delta slowness image computed by Alford rotation methods. The delta slowness image is created at each depth by computing the slownesses at each then computing the average slowness for that depth, and finally subtracting the average slowness from the slowness at each angle. Thus blue zones are faster than average (maximum stress) and red zones are slower than average (minimum stress). a –*

*True anisotropy (calculated via method 1); b – True anisotropy (calculated via method 2); c –false anisotropy (calculated via method 1); d –false anisotropy (calculated via method 2)*

Having ruled out environmental factors, then it is safe to assume the anisotropy is formation related. Now we must consider whether the anisotropy is intrinsic, stress-related, geometric, or a combination thereof.

*Intrinsic and Stress Anisotropy*

When people think of acoustic anisotropy, they are most often thinking of the classic case of a vertical wellbore in an HTI formation. In this scenario, the azimuthal shear velocities are related to stress variations as illustrated in **Figure 8**. Faster velocities indicate higher stress, while slower velocities indicate lower stress. A common interpretation is that if we see anisotropy, then there will be fractures in the fast shear direction and/or borehole breakout in the slow shear direction. However, we must recall that while the sonic measurements can indicate stress variations, they do not necessarily indicate that the rock is fractured or broken…yet! In order to determine if the rock has actually failed we need to examine additional evidence such as electrical images (**Figure 9**), callipers (**Figures 9, 10**), Stoneley Reflector analysis (**Figure 10**), the local stress field (**Figure 11**), as well as the field and well history, e.g. depletions, production, etc., that could have caused changes in the near-field stress regime. We can even use cuttings analysis – shape, size, and condition of cuttings give good hints of the downhole stress

We should also recall that shear measurements are sensitive perpendicular to the axis of the wellbore. Thus, in a horizontal well, the shear anisotropy is sensitive to y- and z- axis variations, while the Stoneley wave can be used to determine the shear velocity (and this estimate stress) in the x-direction.

Stoneley reflector analysis (**Figure 10**) is an old-fashioned but often effective indicator of fractures transecting the wellbore (but won't see fractures parallel to the wellbore). It is well suited to determining vertical fractures in a horizontal well and is often used when a well is drilled laterally through an intrinsically anisotropic formation (such as a shale reservoir) to determine if there are fractures intersecting the wellbore. Unfortunately, Stoneley reflector analysis does not tell us much about the azimuthal stress field as it is only sensitive to impedance contrasts, not stress variations.

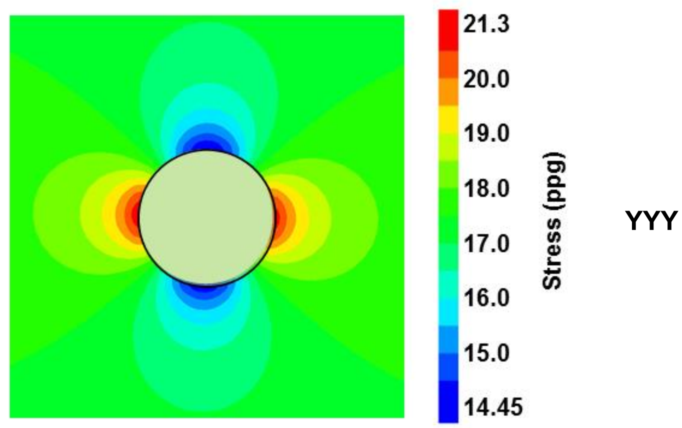


**Figure 8**: *Varying azimuthal stress*

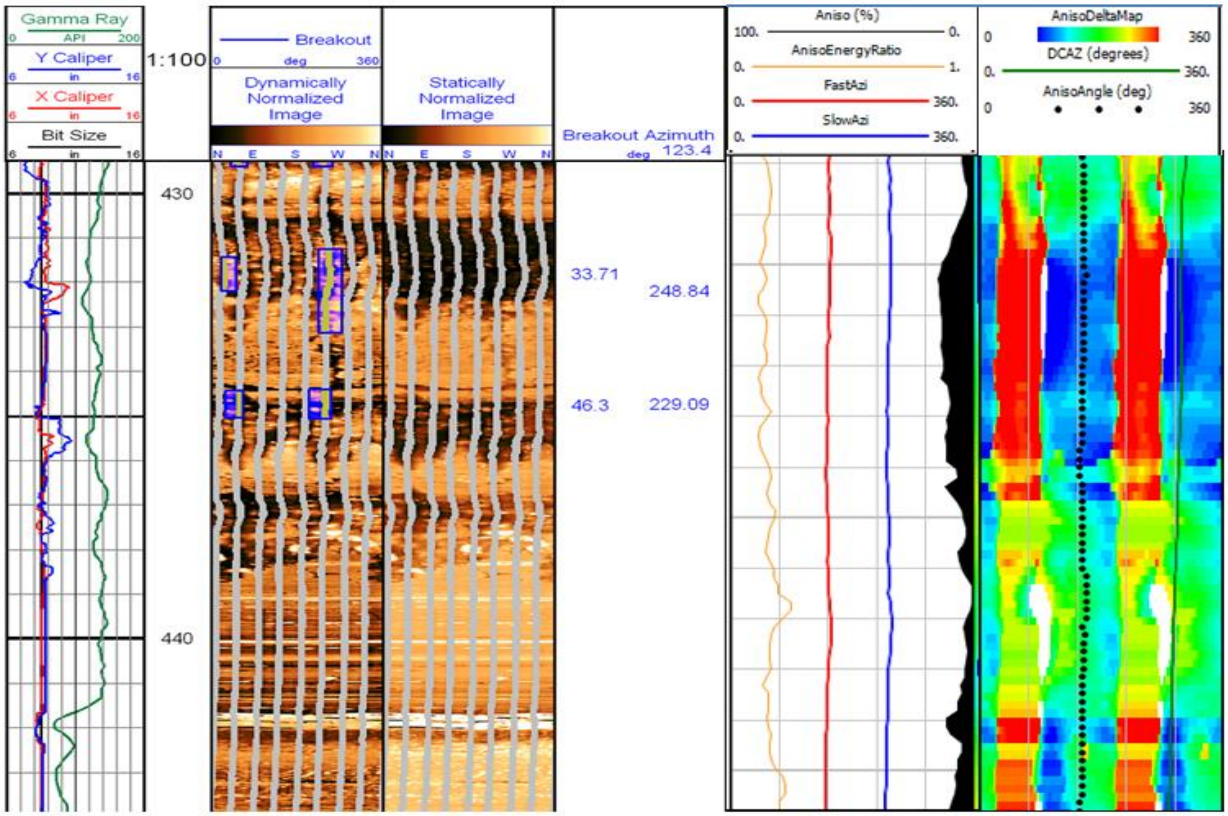


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**Figure 9:** *Electrical images (tracks 3 & 4) may show both fractures and breakouts (but show little variation if the rock has not yet failed). Calliper logs (track 1) show breakout, hole collapse and hole enlargement. Multi-arm/azimuthal callipers are a good indicator of oriented breakout. In this vertical well example, the shear anisotropy (track 7) shows clear azimuthal variation, with the fast shear azimuth (maximum stress) direction at 145-160 degrees and the slow shear direction (minimum stress) at 235-250 degrees. The electrical image and calliper confirm breakouts in the minimum stress direction.*

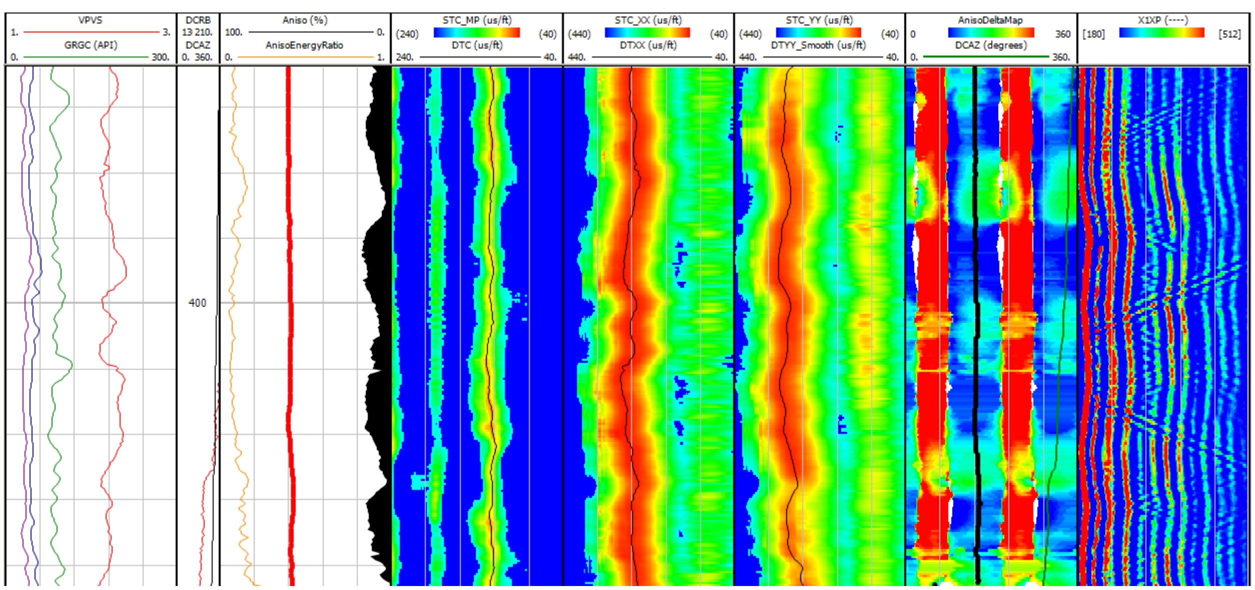


**Figure 10:** *Log example showing a comparison of crossed-dipole anisotropy (track 7), Stoneley reflector analysis (track 8), and calliper features (blue and purple curves in track 1 are the X- and Y- axis callipers).*

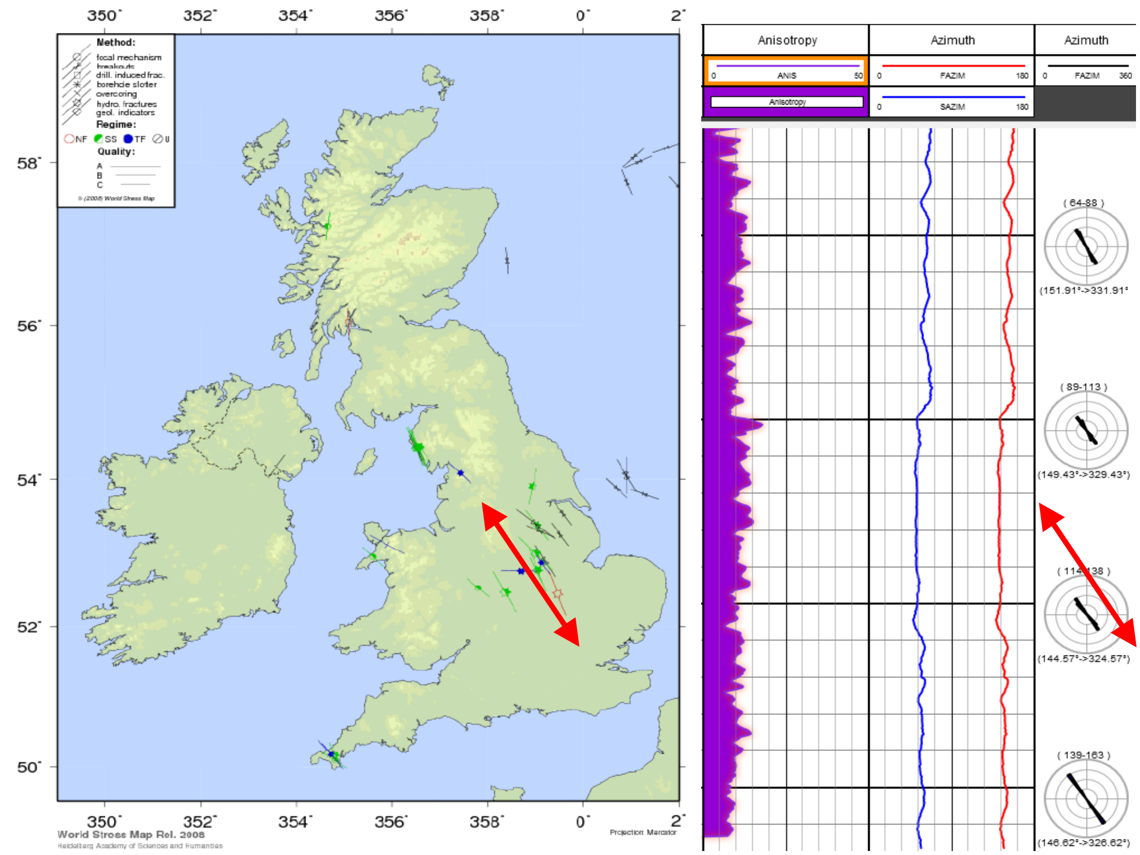


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**Figure 11:** *Example of using the world stress map to determine if the maximum stress direction computed from crossed-dipole anisotropy analysis (right plot) correlates with the local stress direction (left picture)(Heidbach et al, 2008)*

*Stress-induced anisotropy*

When we consider stresses in a formation, we can't ignore the fact that we have dramatically changed the local stress field with the act of drilling a wellbore. The near wellbore stress can thus vary dramatically from the far wellbore stress. This means that we need to understand the depth of investigation of the specific tool collecting the data as well as how the stress field varies with percentage of anisotropy, well azimuth, and well inclination.

*Understanding the depth of sensitivity of acoustic tools: coupling acoustics to geomechanics*

Depth of investigation (DOI) is primarily controlled by the operating frequency of the tool, though also influenced by the formation velocity, mud properties, source type, and tool geometry. In general, tools operating at low frequencies and in fast formations (such as hard rocks) are usually less sensitive to near field stress perturbations compared to tools operating at higher frequencies and in slow/softer formations. For example, under the same stress conditions, higher frequency (10-20 kHz) tools will be primarily sensitive to near wellbore stress perturbation (dashed line, **Figure 12a**) while lower frequency (1-3 kHz) acoustic tools can capture far-field stress conditions (dashed line, **Figure 12b**). Broad frequency tools allow us to measure both the near- and far- wellbore stress perturbations to more fully characterise the anisotropy.

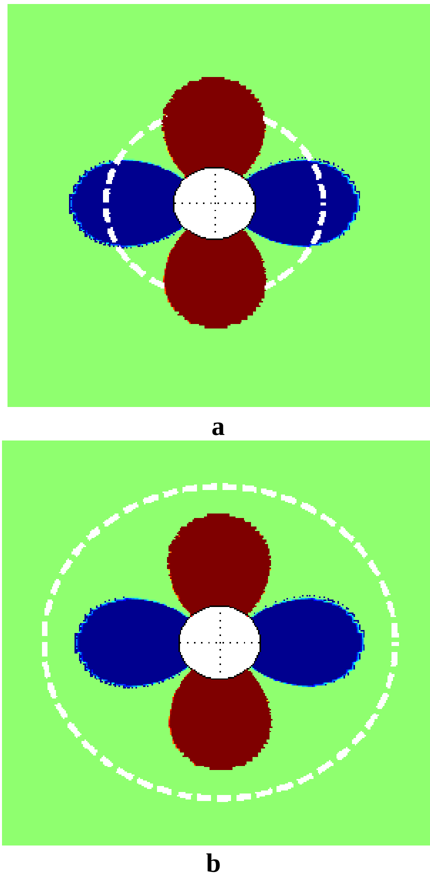

**Figure 12:** *Depth of investigation versus near-wellbore perturbed stress zone: high frequency sonic tool (top) and low frequency sonic tool (bottom). The dashed line indicates the depth of investigation (DOI) of the too. The green zone represents far field and the blue/red contours highlight areas where stresses are perturbed and concentrated*

The formation properties, far-field stresses, wellbore geometry and wellbore trajectory all influence the characteristics of the near wellbore stress field (extent, magnitude, degree of anisotropy and orientation). Thus, geomechanical stress analysis can be used to quantify the characteristics of the far vs. near field, independent of the individual tool response. This is illustrated in **Figure 13** which shows near-wellbore stress concentrations around a vertical wellbore under two different far-field stress conditions (5% and 15% stress anisotropy). The x-axis represents the radial extent into the formation, normalized by the wellbore radius (r/rw) while the y-axis shows the compressive stress concentration magnitude. We see that the near-field stress concentration decays and reaches the far-field value at a distance of about 2.2 times the wellbore radius for 5% in-situ stress anisotropy and at 2.6 times the wellbore radius for 15% in-situ stress anisotropy. In other words, as the in-situ stress state changes, the extent of the near-wellbore stress field varies and can be quantified. The extent of the near wellbore stress field can then be compared to a tool-specific DOI (as a quick look analysis) and/or near wellbore stress field can be coupled with acoustoelastic theory with non-linear elastic constants (Ogden, 1984) to map the velocity field for different near field stress concentrations.

A practical example:

> For 5% in-situ stress anisotropy and an 8.5" wellbore, the non-perturbed zone would begin about 1.5 ft. into the formation. A low frequency signal at 2 kHz in a 100 us/ft formation would "see" approximately 5 ft. into the wellbore, and thus could be expected to measure the non-perturbed stress field. For the same formation and wellbore, if we instead use a 10 kHz measurement, we would "see" only about 1 ft. into the formation and thus be in the perturbed zone.

In addition to the DOI of the tool and variations in far-field stress fields, the trajectory of the wellbore (inclination and azimuth) affects the resulting stress field and acoustic tool responses. **Figure 14** shows the effect of wellbore inclination/azimuth on near-field stress concentration under a normal faulting stress regime. As the inclination and azimuth of wellbore changes, both extent and orientation of the near wellbore stress concentration varies. For example, a sonic tool in a vertical wellbore is affected less by near wellbore stress concentration when compared to a tool in a horizontal wellbore under the same in-situ stress field conditions. The conditions which pose a higher chance of the tool response being affected by the near-wellbore stress concentration are marked with a red background. Note that the chance of the tool response being affected by the near field stress concentration is minimized for a 45 degree wellbore drilled in the direction of minimum in-situ horizontal stress (**Figure 14**). In other cases, the location of maximum compression in the near field rotates around the wellbore.

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The implication of these observations is that acoustic tools will record fast/slow velocities in different magnitudes and orientations around the wellbore depending on their DOI, formation properties, inclination/azimuth of the wellbore, wellbore geometry and in-situ stress field. Thus, an accurate characterization of the near field stresses around a wellbore will help identify potential impacts on the recorded tool response.

The chart shown in **Figure 14** can be particularly useful in job planning, as it can predict the depth of sensitivity for a particular tool, formation, and wellbore trajectory and thus know whether to expect that the sonic data will be from the near wellbore, far wellbore, or both. For example, we can predict whether the shear anisotropy measurements will be dominated by stress-induced effects or intrinsic anisotropy. If we are using the azimuthal shear velocities in real-time (or near real-time) to optimise fracturing, it is critical to know whether we are seeing near-wellbore anisotropy which would likely not add to production (as the stress effects don't extend beyond the shallow perturbed zone), or if they indicate variations in the natural stress field and will thus contribute to production.

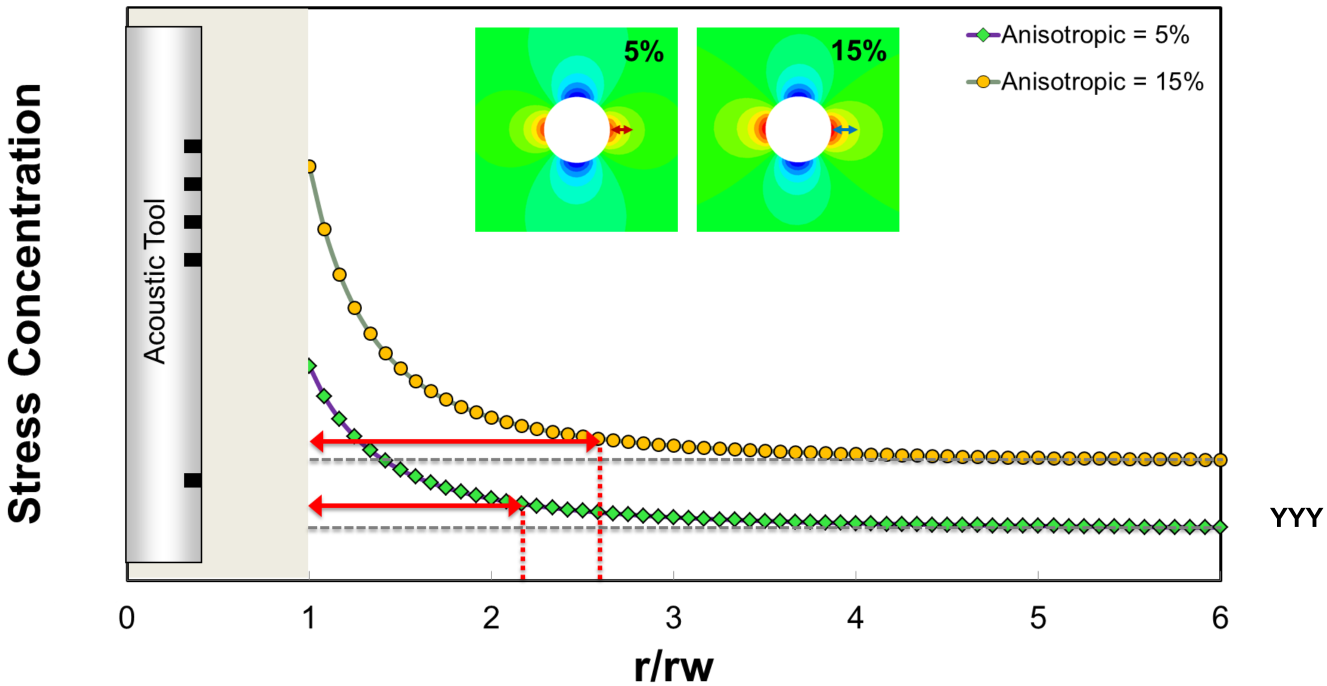


**Figure 12:** *Near-wellbore perturbed stress zone for different in-situ stress anisotropy (5% and 15%). r/rw is the radius (into the formation) that the perturbed zone extends, divided by the radius of the wellbore.*

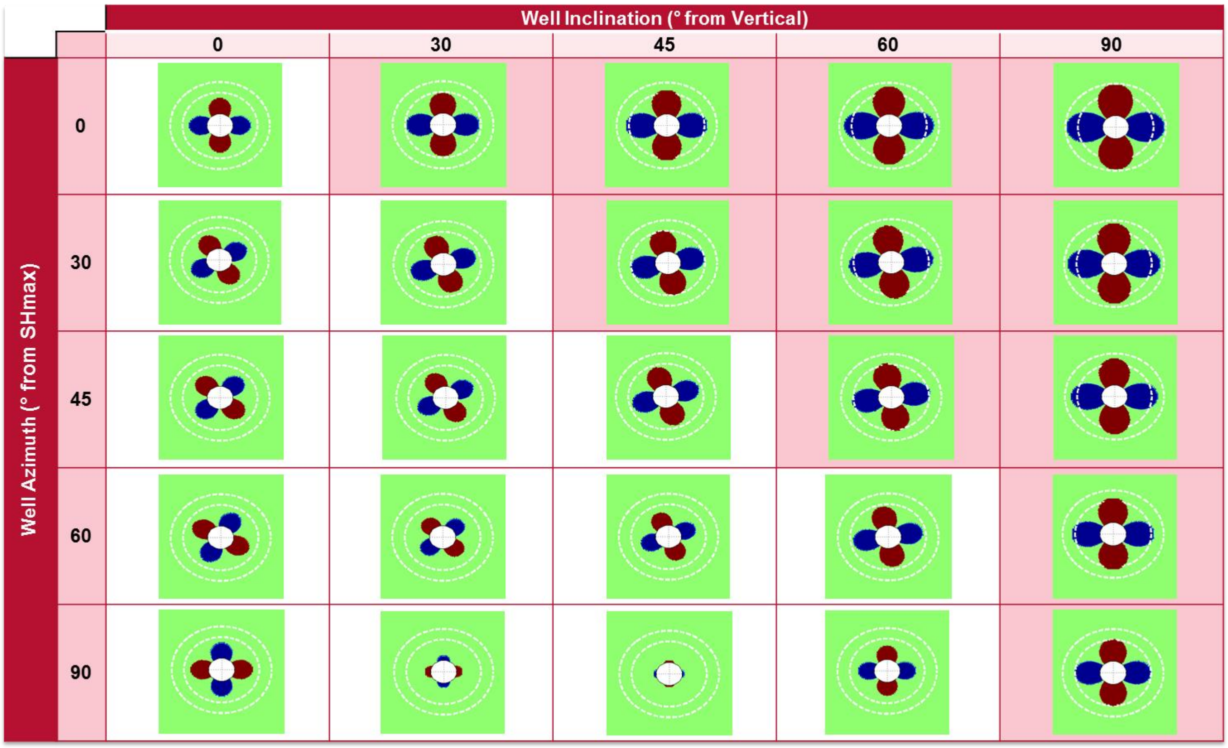


**Figure 14:** *Effects of wellbore inclination/azimuth on near-wellbore perturbed stress zone and tool response. The two dashed lines show range of DOI for a specific tool and indicate an uncertainty range.*

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*Dispersion crossover*

Once we have considered the depth of sensitivity of the azimuthal shear measurements and have determined that the data are suitably broad in frequency to characterize both near-and far- wellbore stress, we can then study the characteristics of the dispersion curves from the fast- and slow- shear waves (Sinha, 1996). The underlying principle is that the depth of investigation is inversely correlated to the frequency (i.e. higher frequencies measure near the wellbore and lower frequencies measure deeper into the formation). **Figure 15** recaps the concept of using dispersion crossover plots to distinguish various forms of anisotropy. The assumption for these plots is that we are considering an HTI environment and a circular wellbore. If the hole is elliptical, it is essential that we take that into account the shifts in the dispersion curve due to geometric dispersion, as it is quite possible in an elliptical wellbore for the geometric dispersion effects to dominate the radial dispersion. It is also possible that geometric dispersion effects on an elliptical hole could give false crossover effects. (Sinha et al, 2000).

1. *(Radially) Homogeneous (Azimuthally) Isotropic:* In the radially homogeneous, azimuthally isotropic case, the only factor causing dispersion is the simple geometric effect. Thus the fast shear and slow shear dispersion curves are identical. (**Figure 15a**)
2. *(Radially) Inhomogeneous (Azimuthally) Isotropic:* In the radially inhomogeneous, azimuthally isotropic case (most commonly near-wellbore stress alteration or drilling damage), the fast- and slow-shear dispersion curves are identical to each other, but they diverge from the homogenous case. In the example of **Figure 15b** the high frequency end of the dispersion curve is slower than the homogeneous case, indicating that the near wellbore zone has been damaged or may be near failure.
3. *(Radially) Homogeneous (Azimuthally) Anisotropic:* In the radially homogeneous, azimuthally anisotropic case, the fast shear dispersion curve matches the homogeneous isotropic case, while the slow shear curve is shifted slower (but has the same shape). This is generally indicative of intrinsic anisotropy due to fine layering, tectonic stresses, or aligned fractures. (**Figure 15c**)
4. *(Radially) Inhomogeneous (Azimuthally) Anisotropic:* Finally, in the radially inhomogeneous, azimuthally anisotropic case,

we have a “dispersion crossover” often used as an indicator of stress-induced anisotropy. In the far field, intrinsic anisotropy dominates the behaviour of the waves, while in the near wellbore, stress induced by drilling the wellbore dominates the behaviour of the waves. (We could actually process for anisotropy at the high frequency limit and the low frequency to determine the actual angle of the near- and far- wellbore maximum stresses). (**Figure 15d**)

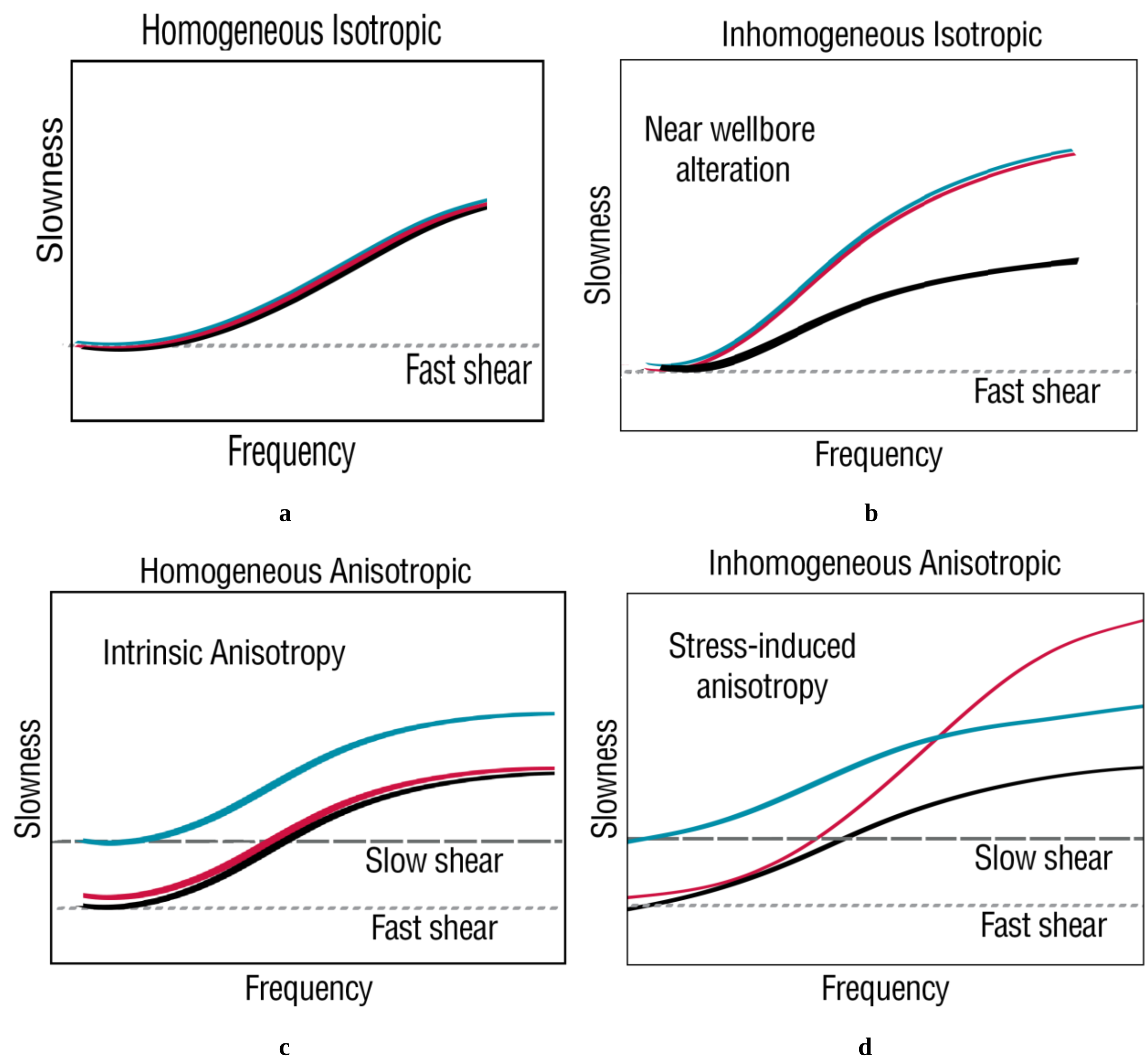


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**Figure 15**: *Diagrams showing dispersion behaviour for common anisotropic scenarios. Red = fast shear dispersion, Blue = slow shear dispersion, Black=isotropic shear. In each case, the first term (homogeneous/inhomogeneous) refers to the radial (from borehole wall into the formation) behaviour and the second (isotropic/anisotropic) refers to the azimuthal behaviour.*

*Geometric Anisotropy (Bed boundaries)*

Geometric anisotropy refers to azimuthal variations in the velocity due to approaching or transecting a bed. This is an asymmetric effect and as such, the best methods for detecting approaching beds are rotational data, such as LWD azimuthal images. Crossed-dipole/Alford rotation methods can give unreliable results due to the assumptions of the methods – i.e. that the formation is symmetric. Processing the individual azimuthal receiver arrays (A, B, C, D, etc.) on non-rotational wireline or LWD tools can be helpful to determine if there are azimuthal variations, though this method yields a low azimuthal resolution. Investigating high frequency vs. low frequency azimuthal responses can be useful, particularly in the case pictured in **Figure 16a**, where the borehole is approaching a bed (rather than transecting it). The low frequency response is expected to be noticeably more influenced by the second layer than the high frequency (shallow) response would be. For cases where the borehole is transecting the bed, we can also detect this case by differences in common receiver vs. common transmitter processing and/or reducing the length of the array used for semblance processing. We also shouldn't forget the simple technique of examining the log above and below the zone of interest. If there is a sharp formation change, then we know that the azimuthal variations seen in crossed-dipole processing are geometrical rather than stress/intrinsic related.

For geometric anisotropy, the depth of detection of the slowness measurements becomes an essential consideration. If the borehole is approaching a nearby bed, such as in **Figure 16a,** the signal recorded by the waveforms will have arrivals from both the formation in which the tool resides as well as reflections from the nearby bed (Pitcher at al., 2011). The depth of detection (the distance at which the response from a nearby formation is detectable) is dependent on the velocities of the two beds. Much as resistivity tools "seek conductivity" – i.e. a resistivity tool located in a low conductivity bed will detect a nearby high conductivity bed from much further away than if the tool was located in the high conductivity bed approaching the low conductivity bed, sonic tools "seek" the fast formation. Thus a tool located in a slow formation approaching a fast formation will detect the nearby bed much further away than would a tool located in a fast formation approaching a slow one. **Figure 16b** shows the general trend of depth of detection with sonic tools. The absolute distance of detection will also depend on the tool design (transmitter-receiver spacing, source frequency, source order, etc.) and environment (hole size, mud properties, etc.).

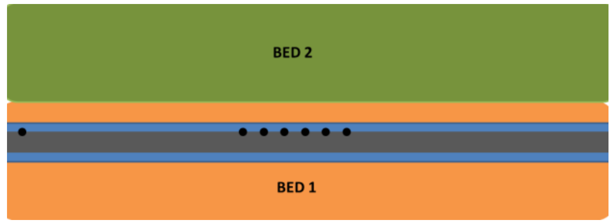


**Figure 16a:** *Diagram of a sonic tool near a bed boundary*

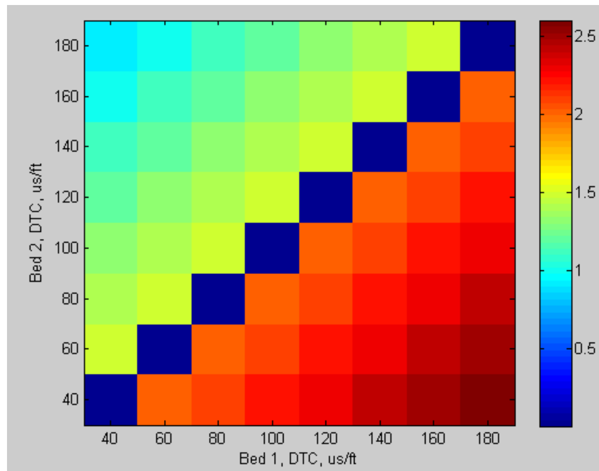


**Figure 16b**: *Illustration of the trend of depth of detection for various bed compressional slowness contrasts; the colour scale is the depth of detection in feet.*

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## CASE STUDY: UNTANGLING INTRINSIC AND GEOMETRIC ANISOTROPY

Unconventional reservoirs represent one of the most promising future sources of energy. Exploitation of most reservoirs depends on horizontal wellbores and hydraulic fracturing to provide a large stimulated reservoir volume in order to achieve economically viable production rates. This has given rise to many new challenges in formation evaluation, well placement and completions.

We present a case study which illustrates the need to separate the geometric anisotropy from the intrinsic formation anisotropy in a horizontal geosteering environment (**Figure 17**). The formation anisotropy needs to be fully understood to enhance the seismic interpretation and future well placement operations, as well as enhance the rock mechanics evaluation. In such a scenario, the incorrect processing/analysis of geometric anisotropy could lead to mis-interpretation of the intrinsic anisotropy, which would impact the final geophysical applications and could adversely affect the production.

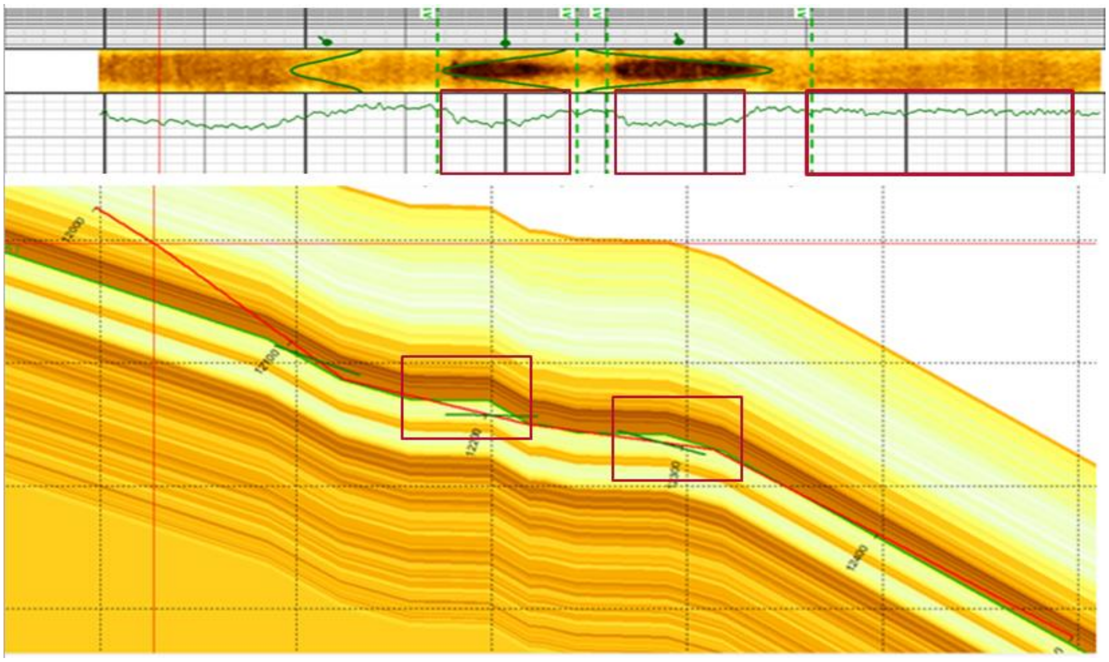

**Figure 17:** *Structural cross-section and wellbore trajectory for the case study*

A 16 bin azimuthal dataset was acquired (**Figure 3**). As a result of crossing bed boundaries, the azimuthal acoustic tool acquired acoustic arrivals from more than just the formation immediately surrounding the wellbore. Unlike in a simple intrinsically anisotropic case, where each of the azimuthal bins exhibits one compressional and one shear slowness values which are then stitched together to create azimuthal slowness images, with the compressional image uniform and the shear image varying due only to the intrinsic anisotropy, some of the bins had three or even four arrivals – a compressional for bed 1, a compressional for bed 2, a shear for bed 1 and a shear for bed 2. These multiple arrivals are easier to see if we plot just the quadrant data (**Figure 18, tracks 2-5**).

If we process the data as we normally would by simply picking the strongest compressional and shear arrivals for each bin, then combining the 16 azimuthal slowness values to generate azimuthal images, we get the results shown in **Figure 19**. If we study this log, we can see that the compressional image (track 3) closely follows the behaviour of the density image (track 2) but that the shear image shows more complex features.

To understand the sonic image responses, we combine knowledge of the lithology, geology, and wellbore trajectory. The gamma ray response, density images and compressional image show us that we are approaching a faster/denser bed below the wellbore (**Figure 19).** The shear image, however, shows a mixed YYY
response with some of the similar features as the compressional image and structural response, but also with intrinsic shale anisotropy (slow in the vertical axis and fast in the horizontal axis). In order to separate the intrinsic and geometric responses on the shear, we used the compressional and density images as a guide and generated two shear images – one of the near-wellbore showing the intrinsic responses from the bed in which the wellbore is located (**Figure 20, track 7**) and one for the far-field effects (**Figure 20, track 6**) which highlights the intrinsic anisotropy.

As a result of this integrated analysis of the azimuthal anisotropy, high confidence in the seismic correlation and optimised production was possible. The completion design for this well was modelled to improve production with optimized stage and cluster perforation placements using the results of the azimuthal sonic interpretation. This case study highlights how the characterisation of the structural geology in relation to the well trajectory can accurately identify nearby bed effects.

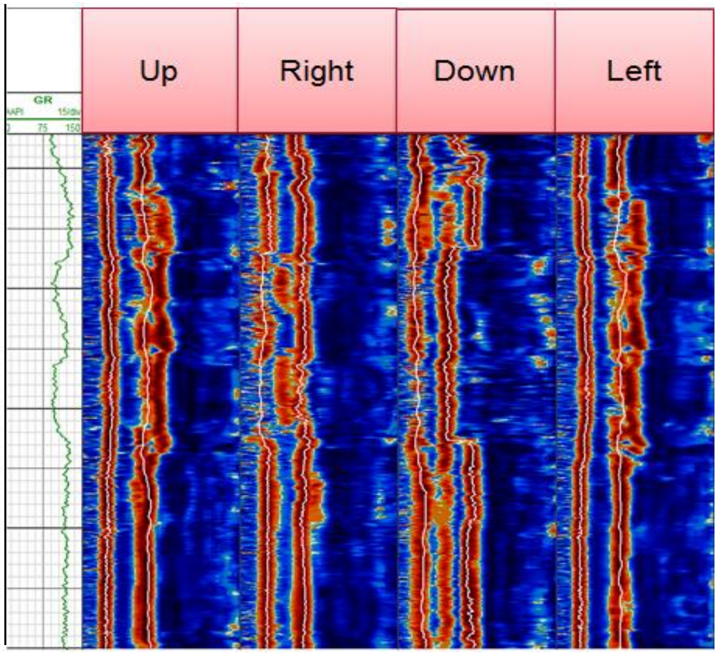


**Figure 18**: Q*uadrant acoustic response for the case study. Track 1 shows the gamma ray and tracks 2-5 show the quadrant semblance maps.*

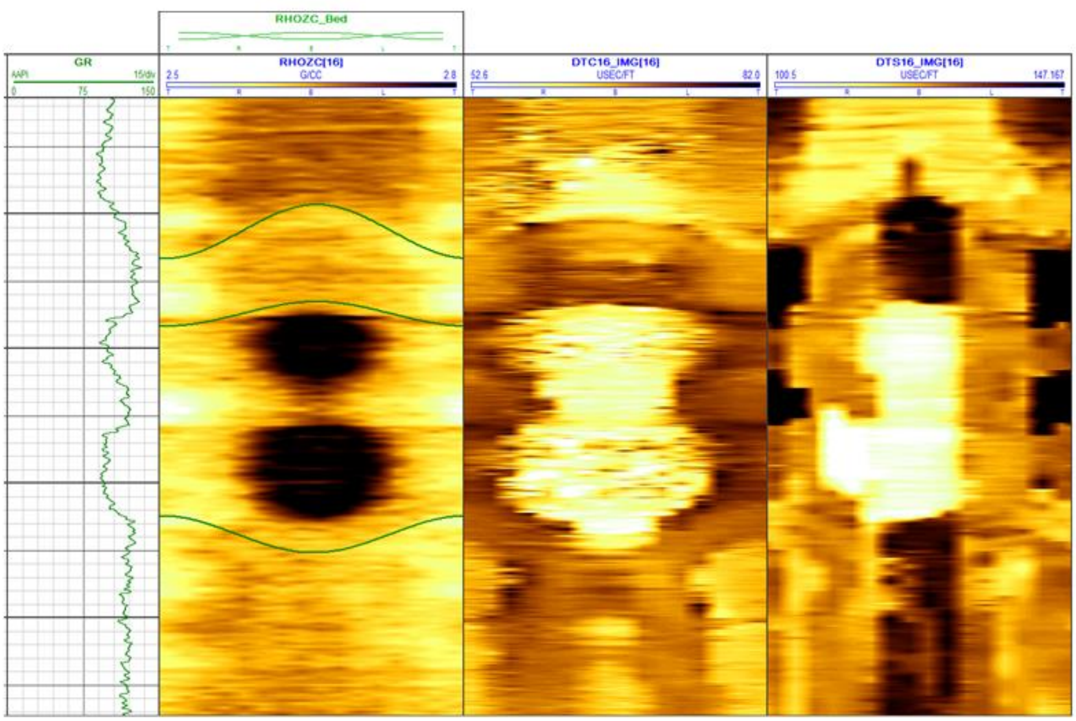


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**Figure 19**: *Comparison of the density image (2nd track), compressional image (track 3) and shear image (track 4). It is clear from the density and compressional images that there is a denser/faster formation below (in the middle of the depth interval), while the shear image also shows a faster formation below in this region, but its azimuthal response is dominated by the intrinsic anisotropy elsewhere.*

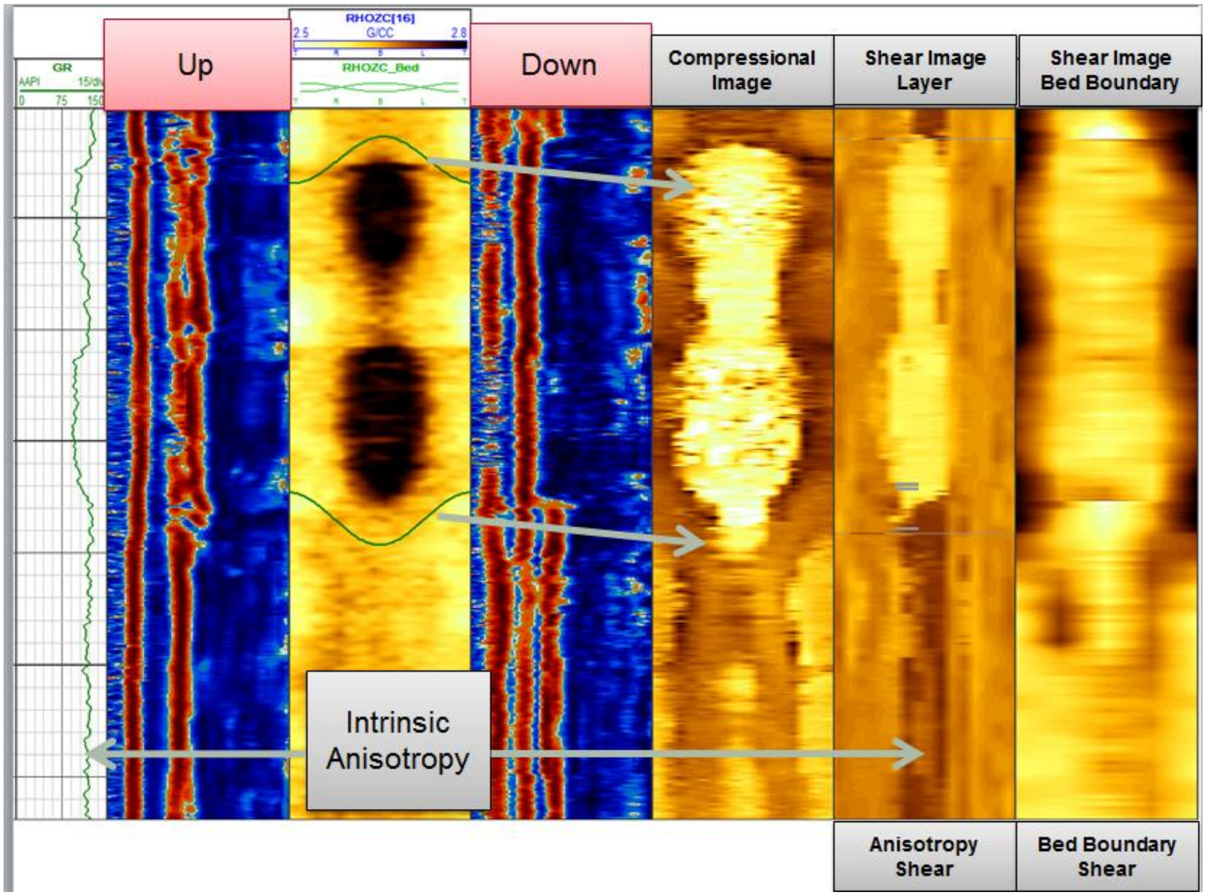


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**Figure 20**: *Integrated interpretation illustrating the use of compressional and density images to determine structural features (approaching a bed below) and shear images with the gamma ray to understand the intrinsic shale anisotropy. Track 5 shows the compressional image, track 6 the shear image from the near-wellbore (enhancing the shale intrinsic anisotropy) and track 7 shows the far-field shear (enhancing the bed boundary effects).*

## SUMMARY – UNTANGLING ANISOTROPY

Acoustic anisotropy can be due to many different causes, including stress variations (natural and drilling-induced), fractures, micro- and macro-bedding, and wellbores crossing dipping beds. While sonic tools are capable of detecting anisotropy effects on the signal response, differentiating between the multiple causes of anisotropy can be challenging. The development of azimuthal acoustic acquisition has been invaluable in the aiding in the understanding of acoustic anisotropy. However, to fully untangle overlapping causes of anisotropy we need to look beyond just the fast & slow shear velocities and the fast shear azimuth to examine the complete picture. Thus, we should also consider:

- Azimuthal compressional response – since the azimuthal compressional velocity will not change with intrinsic or stress induced anisotropy, an azimuthally varying compressional is a good indicator of geometric anisotropy
- Stoneley velocity – indicator of anisotropy on the axis parallel to the wellbore
- Stoneley fracture ID (chevron analysis) – indicator of fractures intersecting the wellbore
- Dispersion crossover analysis – distinguishing near-wellbore (induced) effects from intrinsic features
- Electrical image logs – indicative of fractures, breakouts (near-wellbore measurement)
- Calliper – breakouts and hole shape are an excellent indicator of the minimum stress direction and can be used to calibrate stress calculations
- Azimuthal density images – indicative of geometric anisotropy, inclusions, vugs, etc.
- Gamma ray images – indicative of lithology,

geometric anisotropy

- Azimuthal resistivity logs – indicative of geometric anisotropy and electrical anisotropy, which is often closely related to intrinsic anisotropy, allowing some guidance in separating intrinsic from induced anisotropy. Modern resistivity tools with a broad range of depths of investigation are an aid in determining the bedding geometry.
- Geology – knowing the local geology aids in understanding the stress field (e.g. a nearby salt dome will have profound effects on the local stress field). Knowing the dip of the beds will help understand whether the acoustic anisotropy response is intrinsic, induced, or geometric and can help to determine the vertical and horizontal shear velocities and stresses.
- Local stress fields – knowing the local stress field from published sources or nearby wells can be an effective indicator of intrinsic vs. induced anisotropy as well as understanding if the anisotropy is of a more local nature.
- Depth of sensitivity of the sonic logging tool – knowing the depth of sensitivity will help determine whether the anisotropy seen is a near- or far- wellbore effect
- Field history (production, depletion, nearby wellbores, etc.) – guides an understanding of what perturbations in the local stress field are likely to affect the log response

The trend is now moving towards more complete anisotropy analysis in real-time using real-time acoustic images from LWD to aid in wellbore stability, production enhancement, and seismic integration. This allows us to drill wells more efficiently, plan production while the well is still being drilled so as to be ready to complete the well quicker and optimally.

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