Seismic azimuthal anisotropy analysis after hydraulic fracturing

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Abstract

Many tight sandstone, limestone, and shale reservoirs require hydraulic fracturing to provide pathways that allow hydrocarbons to reach the well bore. Most of these tight reservoirs are now produced using multiple stages of fracturing through horizontal wells drilled perpendicular to the present-day azimuth of maximum horizontal stress. In a homogeneous media, the induced fractures are thought to propagate perpendicularly to the well, parallel to the azimuth of maximum horizontal stress, thereby efficiently fracturing the rock and draining the reservoir. We evaluated what may be the first anisotropic analysis of a Barnett shale-gas reservoir after extensive hydraulic fracturing and focus on mapping the orientation and intensity of induced fractures and any preexisting facts, with the objective being the identification of reservoir compartmentalization and bypassed pay. The Barnett Shale we studied has near-zero permeability and few if any open natural fractures. We therefore hypothesized that anisotropy is therefore due to the regional northeast–southwest maximum horizontal stress and subsequent hydraulic fracturing. We found the anisotropy to be highly compartmentalized, with the compartment edges being defined by ridges and domes delineated by the most positive principal curvature k₁. Microseismic work by others in the same survey indicates that these ridges contain healed natural fractures that form fracture barriers. Mapping such heterogeneous anisotropy field could be critical in planning the location and direction of any future horizontal wells to restimulate the reservoir as production drops.

Introduction

The Barnett Shale is an important unconventional resource play in the Fort Worth Basin, Texas, where it serves as source rock, seal, and trap. Because it has very low permeability, Devon Energy launched a program that hydraulically fractured the rocks in the play in recent years, previously considered marginal, by injecting high-pressure fluid with 10 wells per square mile, thereby significantly improving the production rates. The wide-azimuth seismic survey under our study was acquired after hydraulic fracturing, such that our focus is on mapping the orientation and intensity of induced fractures and natural fractures, with the objective of identification of reservoir compartmentalization and bypassed pay. Our paper builds on Thompson’s (2010) work on the same survey, who reports that none of the eight microseismic experiments conducted within the survey area breached the overlying Marble Falls and underlying Viola Limestone fracture barriers. Anisotropy estimated using a dominant frequency method showed rather uniform east–west-trending anisotropy in both the upper and lower fracture barriers. In contrast, the anisotropy in the producing zones — The Lower Barnett Shale, Forestburg Limestone, and Upper Barnett Shale are highly heterogeneous, indicating fractures propagating in almost all directions. In this work, we perform more detailed analysis of the Lower Barnett Shale, the primary exploration target, and demonstrate the benefit of data conditioning on anisotropy measures.

In shale gas reservoirs, natural fractures, induced fractures, and azimuthal variation of the horizontal stress cause azimuthal anisotropy. Seismic P-waves traveling through such media exhibit azimuthal variation in traveltime, amplitude, AVO, and tuning. If these variations can be accurately measured, valuable information related to either fractures and/or the stress field can be inferred. Knowledge of fracture orientation and intensity is critical for appraisal, development, and hydrocarbon production. A better understanding of induced fracture orientation and intensity can help evaluate the success of a completion project, the possible need for restimulation, and identify bypassed pay. Understanding the maximum stress field is helpful in the choice of drilling direction and cost-effective completion.

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The most straightforward physical model to describe azimuthal anisotropy consists of a set of aligned vertical cracks embedded in an isotropic, homogeneous matrix (Thomsen, 1995). This horizontal transverse isotropic (HTI) model forms the basis for almost all of the current fracture characterization workflows. To map the azimuthal anisotropy of the hydraulic fractures in the Barnett Shale under this study, we have three assumptions:

1) The Barnett Shale can be considered to be characterized by orthorhombic symmetry (flat layers and a dominant stress direction) such that azimuthal anisotropic workflows work effectively.

2) Natural fractures have marginal contribution to azimuthal anisotropy compared to densely distributed hydraulic fractures. Thompson (2010) shows that there are few if any open natural fractures in the Barnett Shale in the survey and those fractures originally associated with the structural deformation seen on curvature volumes are now cemented. In addition, there are no faults in this survey.

3) The northeast–southwest trending maximum horizontal stress, SH, gives rise to induced drilling fractures seen in vertical image logs in this and neighboring surveys. This anisotropic stress fields opens small microfractures which in turn gives rise to seismic anisotropy.

The first azimuthal anisotropy workflow measured the variation of velocity with azimuth (VVAz). VVAz requires picking the top and bottom of the reservoir at different azimuths thereby providing measures of the elliptical behavior of the phase velocity as seismic energy propagates along different azimuths through the fractured system. VVAz provides a robust measure of the average fracture properties of a relatively thick formation (Jenner, 2001; Sicking et al., 2007; Xu and Tsvankin, 2007; Roende et al., 2008; Treadgold et al., 2008). A more recently introduced competing method is amplitude variation versus azimuth (AVAz), which is applied to phantom horizons through the offset- and azimuth-limited amplitude data volumes and provides more localized, higher resolution information about the fractured reservoir (Rüger, 1998; Luo and Evans, 2004; Goodway et al., 2006; Xu and Tsvankin, 2007). Both techniques have advantages and disadvantages. Effective VVAz analysis requires accurately picking the far-offset seismic events at different azimuths. These large-offset events are often corrupted by noise, suffer from migration stretch, and may not be available if the target is too deep. Effective AVAz analysis requires a uniform, highfold acquisition; nonuniform distribution of the fold in different azimuths introduces errors such that a wise normalization needs to be applied.

We begin with a review of special data conditioning, including azimuthal binning based on the azimuth from midpoint to image point, RMO correction, and prestack structure-oriented filtering. Next, we introduce our measures of anisotropy intensity and strike. Applying this workflow to the data, we correlate the results to coherence and curvature attribute measures of structural deformation. Finally, we perform a detailed azimuthal anisotropic analysis of the Lower Barnett Shale, the primary exploration target, and evaluate the structure control of hydraulic fracturing.

**Methodology**

**Data conditioning**

Unlike conventional azimuthal binning that sorts using the azimuth of the vector connecting surface source and receiver locations, Perez and Marfurt (2008) propose an azimuth binning algorithm that places each migrated sample into an azimuth bin computed from the source-receiver midpoint to the image point (Figure 1a). Our new binning method has proven to be effective in improving illumination of faults and fractures for two reasons. First, it separates the weak side-scattered component caused by fault terminations, fractures, and steep reflectors from the stronger near-vertical reflections that fall within the sagittal plane, and second, it avoids mixing events with different residual moveout (RMO) if azimuthal velocity anisotropy is present. We migrate the data into different azimuth and offset bins as shown in Figure 1b. In our study, the data were migrated into four azimuthal sectors with central azimuths of 0° (north–south), 45° (northeast–southwest), 90° or –90° (east–west), and 135° or –45° (northwest–southeast). Because a single migration velocity is used and velocity variation with azimuth is ignored, the RMO in the common reflection point (CRP) gathers is azimuthally variant, requiring different RMO corrections for each azimuth.

Recent trends in seismic acquisition of large offset data make nonhyperbolic moveout corrections indispensable in most scenarios. Effective anisotropy due to thin beds and intrinsic anisotropy associated with mineral alignment are often well represented by a vertical transverse isotropy (VTI) model. As one of the classic VTI media, shale typically gives rise to the well-known “hockey stick” at the far offsets seen on migrated gathers (Figure 2a), which needs to be addressed before we search for HTI anomalies. Ignoring VTI effects will result in image degradation or misleading results. Weak VTI anisotropy can be quantified by estimating Thomsen’s parameters. Currently, most processing shops are readily able to handle VTI anisotropy by iterative use of VTI anisotropic reflection tomography and prestack depth migration. Because reflection dips in the study are less than 2°, we adopt a faster and more straightforward two-step flow. This RMO correction flow is based on the principle that, after isotropic prestack time migration, (1) the short-spread is quite flat and (2) the large offset beyond (offset/depth > 1.0) can be fit by a fourth-order polynomial: \( \Delta T = a + bx^2 + cx^4 \), where \( \Delta T \) is the residual time, and \( x \) is the offset. A representative CRP gather after RMO analysis is shown in Figure 2b.

There are many ways to perform prestack data conditioning. Our approach (Figure 3) is similar to one...
described by Singleton (2009) who uses the structural dip and azimuth computed from migrated, stacked data as the structural control in 3D structure-oriented filtering of each common offset and azimuth volume. Alternative structure-oriented filters include principal component and alpha-trim mean filters. This data conditioning method uses the coherence of the stacked data volume to preserve edges, preserves the AVO signature of gathers, and enables effective signal-to-noise ratio (S/N) enhancement. Figure 4a and 4b shows representative CRP gathers from four different azimuths.

Figure 1. Diagrams showing (a) the geometry of the side-scattered signal and (b) the output of the migration divided into different offset and azimuth sectors. The new image point azimuth binning approach embedded in our prestack time migration (PSTM) algorithm sorts the data by azimuth as it is imaged in the subsurface (after Perez and Marfurt, 2008): \( X_g \) is the receiver point, \( X_s \) is the source point, and \( X_i \) is the image point.

Figure 2. A representative CRP gather (a) before and (b) after RMO analysis. White arrows indicate hockey sticks. The large offset RMO (or hockey stick) beyond 7000-ft offset is corrected to be flat after RMO analysis in the target zone of Barnett Shale, which is critical to later fracture characterization. The depth to the Barnett Shale target is about 7000 ft.
before and after two passes of edge-preserving principal component structure-oriented filtering. The improvement in gather quality is readily apparent on the conditioned data. Note that undesirable random, uncorrelatable energy components are diminished after conditioning, even though the filters are applied in the inline/crossline domain rather than across offsets or azimuths.

**Azimuthal anisotropy**

If an otherwise homogeneous horizontal layer contains vertically aligned parallel fractures (the HTI model), seismic velocity will vary with azimuth. In addition, many other P-wave seismic attributes such as travelt ime, reflection amplitude, attenuation coefficient, and spectrum will also exhibit azimuthal anisotropy. Given the HTI nature of the Barnett Shale, the introduction of horizontal stress and/or vertical natural fractures gives rise to orthorhombic media. If one of the fracture sets is dominant, or as in our case, there are no open fractures, but rather a difference in value between the maximum and minimum horizontal stresses, the azimuthal variation can be represented by a sinusoid that has a periodicity of 180°. Our survey was acquired with

**Figure 3.** Workflow used to condition the prestack migrated gathers. This process is both edge- and AVO-preserving.

**Figure 4.** Representative migrated CRP gathers from four different azimuths (a) before and (b) after the prestack structure oriented filtering. Notice the great enhancement of the S/N.
anisotropy analysis in mind, with the fold approximating 400 and almost isotropic source-receiver spider diagrams (Thompson et al., 2010).

Figure 5 describes our workflow. We start by migrating the data into azimuth-offset bins. Next, we apply the conditioning to CRP gathers and compute seismic attributes (AVO gradient, impedance, and peak frequency) from each azimuthally limited volume and flatten them along the picked horizon from the associated azimuth. Assuming azimuthal variation of a particular seismic attribute caused by a set of cracks aligned with a preferred azimuth (or alternatively, nonuniform horizontal stresses), the attribute can be represented by an ellipse. The objective function for ellipse fitting is defined as

\[ E = \sum_{j=1}^{J} \left( a_j - \bar{a} + \varepsilon \cos^2(\phi_j - \psi) \right)^2, \]  

(1)

where

\[ \bar{a} = \frac{1}{J} \sum_{j=1}^{J} a_j \]  

(2)

is the average of the attribute \( a_j \) measured along azimuth \( \phi_j \), \( \psi \) is the azimuth corresponding to the maximum of \( a_j \), and \( \varepsilon \) is a measure of the degree of ellipticity.

The confidence \( c \) of the elliptical fit is

\[ c = 1 - \frac{E}{\sum_{j=1}^{J} (a_j - \bar{a})^2 + r}, \]  

(3)

where \( r \) is a small number to avoid division by zero.

Note in equation 3 that if \( a_j = \bar{a} \) for all azimuths, \( \phi_j \), \( c = 1.0 \), implying that we are confident that we have a locally isotropic media, with \( \varepsilon = 0 \).

If the geology can be represented by HTI symmetry or orthorhombic symmetry (flat layers and one set of vertically aligned fractures), \( \psi \) will represent the fracture strike, while \( \varepsilon \) will be a measure of the fracture intensity. If the geology cannot be represented by HTI symmetry or orthorhombic symmetry (i.e., two dominant fracture sets

Figure 5. Workflow to calculate azimuthal anisotropy from a seismic attribute \( a \). A cosine of azimuth \( \Psi \) and amplitude \( \varepsilon \) is fit to the value of corresponding samples (represented by green squares) from each azimuthally limited input volume. Here, \( \Psi \) is the strike of the largest value of \( a \), \( \varepsilon \) is anisotropic deviation from a constant value, and \( c \) is the confidence of the least-squares fit.
or nonvertical fractures), then the objective function in equation 1 needs be redefined to predict the azimuth and dip of the dominant fracture sets.

Data analysis

Anisotropy

We compute the AVO gradient from azimuthally limited seismic gathers at azimuths 0°, 45°, 90°, and 135° and perform AVAz analysis through the above workflow. Figure 6a shows one vertical seismic section AA′ with interpreted Lower Barnett Shale, Ordovician unconformity, and the phantom horizon for later analysis. Figure 6b is the AVO slope from 135° along the Phantom horizon 10 ms above the Ordovician unconformity. Figure 7a, 7b, and 7c is the predicted anisotropy strike, anisotropic intensity in the Lower Barnett Shale, and the confidence of least-squares fitting estimated from AVAz. The drilling program consisted of horizontal wells oriented northwest-southeast because the maximum horizontal stress orients along the northeast-southwest direction. Figure 7a contradicts the widely accepted hydraulic fracture model and suggests that the induced fractures have widely variable orientations. We interpret the zones with consistent orientation to be “fracture compartments,” which is consistent with the observation made by Thompson (2010) and Perez-Altamar (2013) that the microseismic clouds in the same survey “avoid” the ridges that contain hard-to-stimulate healed natural fractures and are “drawn” to the intervening bowls. In general, we expect the induced fractures generated by the first hydraulically fractured well to propagate perpendicularly or near perpendicularly to the minimum horizontal stress. Nevertheless, the subsequent fractured wells in the same compartment may follow or modify the stress regime initiated by the previous wells (Miskimin, 2009). As more wells are drilled, the local stress regime continues to be modified, thereby influencing the behavior of subsequent stimulation jobs.

Correlation with curvature

In 2D, curvature is defined as the reciprocal of the radius of a circle tangent to a surface. Anticlinal, synclinal, and planar features are represented by positive, negative, and zero values of curvature. In 3D, we fit each point in a surface with two orthogonal tangent circles. Together, these circles define domes, ridges, saddles, valleys, bowls, and planes. Nelson (2001) states

![Figure 6](image1)

![Figure 7](image2)

**Figure 6.** (a) Vertical seismic section AA′ with interpreted Lower Barnett Shale, Ordovician unconformity, and the phantom horizon for later analysis. (b) AVO slope from 135°.

**Figure 7.** Phantom horizon slices 10 ms above the Ordovician unconformity of (a) the azimuth of anisotropy, (b) the intensity of anisotropy, and (c) the confidence of least-squares fitting from AVAz.
that the zones of greater curvature are related to zones with greater strain, such that fractures often occur in folded rocks, especially near the structural hinge line. Coherence sees faults that have significant displacement across them and joints that have undergone significant diagenetic alteration. It does not in general “see” fractures. Curvature measures strain and thus is often directly correlated to fractures (Hunt et al., 2010; Staples, 2011; White et al., 2012). With the passage of time and the change in stress direction, these fractures can be cemented, otherwise diagenetically altered, closed, or opened.

Hart (2002) and Nissen et al. (2009) use curvature to map fractures in tight gas sand and carbonate reservoirs, respectively. In Nissen et al.’s (2009) work, one of two sets of diagenetically altered joints in the Mississippian Lime has been filled with overlying Cherokee Shale, thereby forming flow barriers. While anisotropy measures and curvature are mathematically independent, both provide indirect inference about fractures; we therefore anticipate correlations between them through the underlying geology.

Figure 8 shows the phantom horizon slices of $k_1$ most-positive curvature 10 ms above the Ordovician unconformity extracted from azimuthally limited stacks of (a) 0°, (b) 45°, (c) 90°, and (d) 135°. The reason why phantom horizon (parallel to the picked horizon) slices are chosen is that we expect to look at the anisotropy inside of the Barnett Shale. The four maps provide slightly different imaging of structural lineaments with better focusing in some directions and more smearing in other directions. Other than illumination issues, we do not expect or observe any difference in the curvature with azimuth. Figure 9 shows the Sobel filter coherence maps from azimuths (a) 0°, (b) 45°, (c) 90°, and (d) 135°. Apparently, the geologic discontinuities from the four azimuths are illuminated differently in coherence maps, especially the circular karst features denoted by white arrows. We do expect subtle differences of coherence with azimuth, with subtle fractures perpendicular to the illumination azimuth being somewhat better defined (Sudhakar et al., 2000).

In Figure 10a, we corender the strike from our AVAz analysis $\psi$ with most-positive principal curvature $k_1$. Note that structural highs seem to form the boundary of different reservoir compartments, each of which has a distinct azimuth, implying that azimuthal anisotropy and hence fracture orientation is independent, but consistent within a reservoir compartment delineated by structure highs. In Figure 10c, we corender anisotropic intensity
with the same curvature map, and find those structurally highs generally appear to correlate to low anisotropic intensity. Thompson et al. (2010) show that microseismic events generated by hydraulic fracturing avoid these ridges. They postulate that these ridges were fractured during the deformation process and subsequently calcite filled, making these zones harder, and hence serving as a barrier to hydraulic fracturing. Rich and Ammerman (2010) find in a different area of the Fort Worth Basin that hydraulic fracturing of wells drilled through such ridges resulted in microseismic events propagating linearly parallel to the ridges with a simultaneous drop in pressure, suggesting that it was easier to pop open the weaker calcite-filled fractures than virgin rock. In summary, the two maps suggest that hydraulic fracturing is controlled by heterogeneities in the rock due to prior deformation and the present-day stress regime is modified by hydraulic fracturing, such that subsequent fractures result in a locally uniform anisotropy strike.

We also corendered the anisotropic measures with $k_2$ most-negative curvature, and found very little correlation between them. Indeed, Thompson (2010), working the same survey, finds that microseismic events occur in bowl-shaped structures, avoiding the ridges, regardless of how the wells penetrated the structure.

Figure 10b and 10d shows the composite images of coherence with predicted fracture strike $\psi$ and anisotropic intensity $\varepsilon$, respectively. It is readily apparent that the discontinuities mapped by coherence are also correlated to the hydraulic fracturing of the lower Barnett Shale, with rocks in the vicinity of coherence anomalies (dark lineaments) appear to form some fracture barriers.

Conclusions

In the survey under study, it is known that the maximum horizontal stress is along the northeast direction. The strike of anisotropy shows strong spatial variability but interesting “compartmentalization” with each compartment having the same strike of anisotropy. These compartments are strongly correlated to ridges and domes defined by the most positive principal curvature, suggesting that these structural highs either serve as a fracture barrier or otherwise modify the local stress regime. Contrary to conventional assumptions, the measured anisotropy and hence the inferred direction of the fractures are highly heterogeneous, indicating fractures propagating in almost all directions rather than being parallel to the regional maximum horizontal stress.

Figure 9. Phantom horizon slices 10 ms above Ordovician unconformity through the Sobel filter similarity computed from azimuthally limited seismic volumes about (a) 0°, (b) 45°, (c) 90°, and (d) 135°. Note how the collapse features indicated by the block white arrows and the northeast–southwest-trending fault indicated by the block black arrows are illuminated differently at the four azimuths.
direction. We hypothesize that the first hydraulically fractured well generates induced fractures perpendicular or nearly perpendicular to the minimum horizontal stress, with subsequent wells in the same compartment following, or further modifying the stress field initiated by the previous wells. Microseismic work by others in the same survey indicates that these ridges contain healed natural fractures that form fracture barriers. Mapping such a heterogeneous anisotropy field could be critical in planning the location and direction of any future horizontal wells to restimulate the reservoir as production drops. Based on the observation in this work, the quantitative comparison of the variation of production rates in the Barnett Shale from different fracture compartments will be very helpful to understand the hydraulic fracturing and provide valuable hints for future stimulation, which will be our research.

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**References**


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