Building geologically plausible anisotropic models using well data and horizon-guided interpolation

In a Gulf of Mexico case study Olga Zdraveva,[1*] Andrey Bakulin[1,2] and Yangjun (Kevin) Liu[1] show that derivation of anisotropy parameters from multiple wells and a horizon-guided approach to their interpolation can deliver more geologically plausible velocity models for imaging seismic data compared to a conventional approach that assumes a single smooth anisotropy profile hang off a shallow horizon.

Depth imaging with anisotropic velocity models has been shown to deliver more accurate images than traditional data processing methods. Accounting for anisotropy is particularly important for complex geologies but should ideally be included in all imaging projects as the Earth is inherently anisotropic. While imaging in complex settings may require tilted transversely isotropic (TTI) models, anisotropic depth imaging with vertical transversely isotropic (VTI) models has become the dominant practice in the seismic industry.

A VTI model velocity field requires three parameters: symmetry-axis (vertical) velocity (V_{P0}) and Thomsen parameters ε and δ. The challenge of building such models is that it is not feasible to rely on seismic tomography to derive multiple parameters in an entire 3D volume because inversion of seismic data alone for all three parameters is highly non-unique (Tsvankin, 2001). The current industry practice typically involves deriving a single smooth profile of Thomsen parameters ε and δ based on limited well control in areas of flat-layered geology. This profile is propagated throughout an entire volume by hanging it off the water bottom or another shallow horizon. Thomsen parameters are kept fixed while velocity along the symmetry axis is updated by tomographic inversion of reflection seismic data (Woodward et al., 2008). This process represents an improvement compared to the isotropic models used in the past, but suffers from several limitations, including:

1. The use of a single anisotropy profile disregards lateral variation of anisotropy in the subsurface.
2. Anisotropic volumes that follow water bottom topography do not represent the structure of subsurface geology.
3. The single anisotropy profile is likely to be overly smoothed in the vertical direction because fine details cannot be accurately propagated in a 3D volume with complex geology.

The goal of the presented approach is a workflow that overcomes these limitations to build more geologically plausible

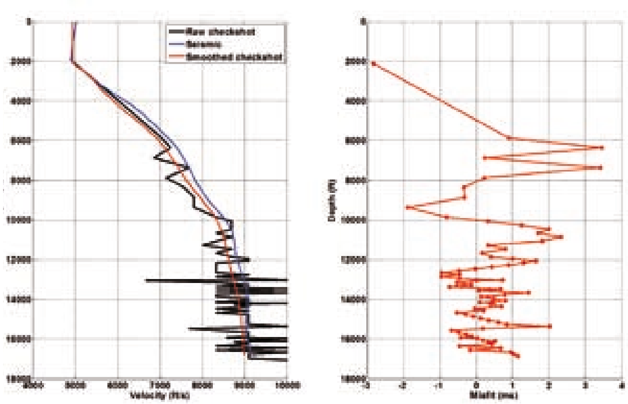

Figure 1 Left: Velocity profiles at one well location: raw checkshot velocity (black), initial seismic model derived with tomography (blue), and smoothed checkshot velocity (red). Right: traveltime residuals for the smoothed checkshot velocity profile.

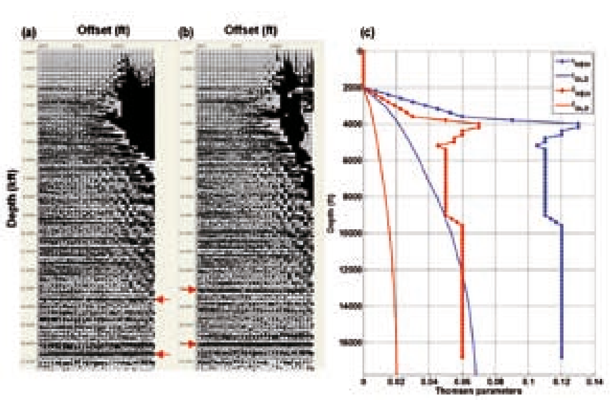

Figure 2 CIP gathers using (a) initial model and (b) model derived from 1D manual layer-stripping inversion at the well location. Note upward movement of seismic horizons shown by red arrows. Panel (c) shows profiles of Thomsen parameters ε and δ for initial model (solid lines) and derived model (lines with circles).

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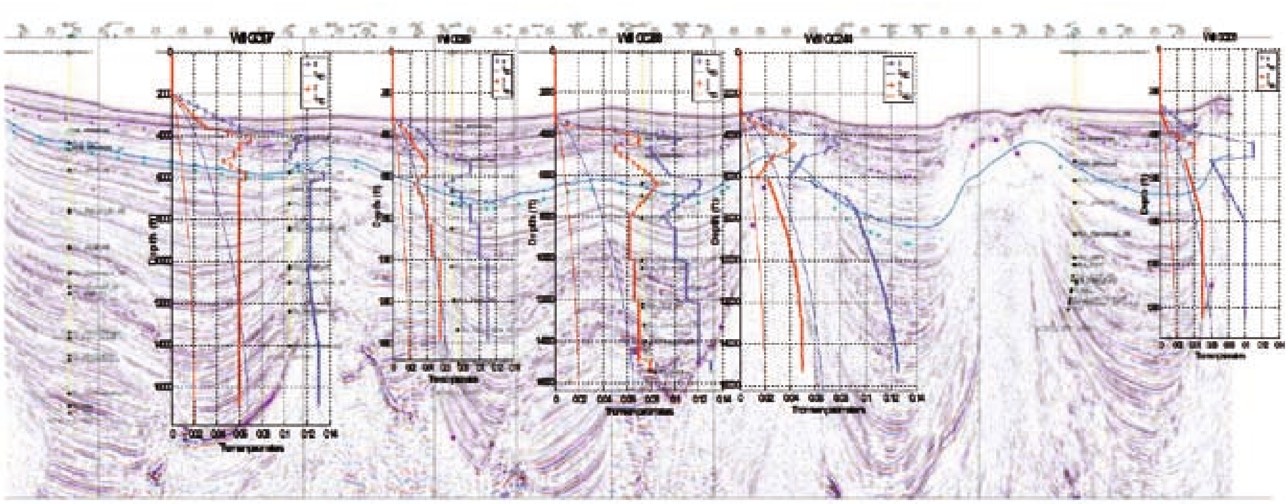

Figure 3 Arbitrary line through the seismic image produced with Kirchhoff migration using the initial model with five of the profiles of Thomsen parameters ε and δ (lines with circles) overlaid at corresponding well locations. Note that highly anisotropic shallow layer correlates with the structure and is consistent across the mini-basins.

anisotropic models by using data from multiple wells and interpolating along interpreted horizons.

Building an extensive anisotropic model with data from multiple wells

The workflow assumes that suitable measurements from several wells are available for building the velocity model, such as checkshot and VSP data, markers, and sonic logs. The objective is to build a VTI depth model that fits all the well data and also fits the seismic data to be imaged. At a high level, the proposed workflow consists of three major steps:

1. Derive local anisotropy profiles around existing wells.
2. Interpret key seismic horizons.
3. Populate 3D velocity model with anisotropic parameters using horizon-guided interpolation of the derived anisotropic profiles.

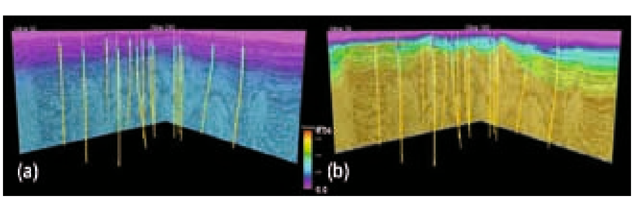

Figure 4 Sections through Thomsen δ volume for (a) initial model and (b) final calibrated model. Tracks of the 18 wells are colour-coded with their corresponding Thomsen δ profiles.

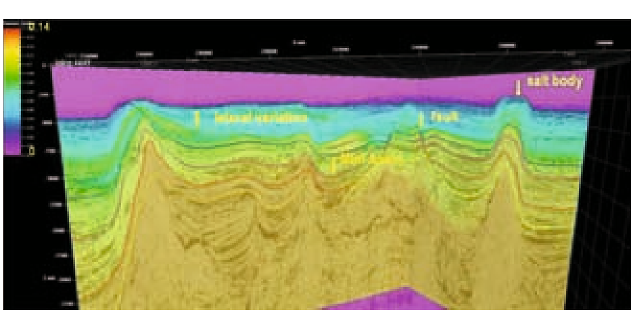

Figure 5 Sections through Thomsen ε volume for the newly constructed well-calibrated model showing the seven interpreted horizons used for interpolation of anisotropy parameters.

Deriving local anisotropy profiles at wells can be done using 1D manual layer-stripping inversion or local tomography (Bakulin et al., 2009). Both of these approaches assume that anisotropy is slowly varying along horizontal or dipping layers. However, the sole deliverables of the first step are profiles of anisotropic parameters along the individual wells. Horizons interpreted in the second step are used to guide the propagation of anisotropic properties between wells. The third step of interpolating the anisotropic parameters between wells is broken into four sub-steps:

1. Convert anisotropy profiles along each of the wells from well depth to seismic image depth.
2. Interpolate anisotropy profiles between wells in seismic image depth.
3. Update vertical velocity in the model to maintain the same normal moveout velocity.
4. Transform to a new seismic image depth. In the example presented below, this is implemented as a simple vertical stretch.

Case study from Green Canyon, Gulf of Mexico

The workflow described above has been applied to a wide-azimuth 3D seismic dataset covering 100 OCS blocks of the northern part of the Green Canyon area in the Gulf of Mexico. The structural framework for interpolating anisotropy profiles was based on interpretation of seven horizons. A public database provided checkshot data from 18 wells in the area, selected to be in areas of near-zero dip and away from salt. The 3D data had previously been migrated using a regional velocity model – the 'initial model' referred to below.

For each borehole, vertical well velocity profiles were derived by traveltime-preserved checkshot smoothing using the algorithm of Lizarralde and Swift (1999) modified to handle uneven sampling. This process captures the low-frequency trend of the well velocities and ensures that there is no bias that may distort time-depth conversion (Figure 1). Some high-frequency details, considered inappropriate for a macro-velocity model, were deliberately excluded. For this example project, local 1D manual layer stripping inversion was performed at each well location, and velocities fixed to smoothed checkshot velocity followed by the derivation of profiles of Thomsen parameters ε, and δ. Common-image point (CIP) gathers are flat for both the initial and derived models (Figure 2). However, the borehole-calibrated model, in which velocities are equal to well velocities, has significantly higher Thomsen parameters. The profile of the derived Thompson parameters suggests the presence of shallow layers with high levels of anisotropy that were not included in the initial model. As a result, all seismic reflection events moved upwards. The highly anisotropic shallow layer was found to be consistent across the mini-basins of the project area (Figure 3).

Before interpolation, anisotropic profiles need to be converted to seismic image depth. This study applied simple 1D transformation by first converting the profiles to time using well velocities followed by conversion to depth using seismic vertical velocity in the initial model. In the next step, Thomsen parameters derived from the 18 wells were propagated throughout the 3D model with interpolation guided by the seven interpreted horizons. For each layer, top and bottom surfaces were used as a guide. With this approach, anisotropy generally conforms to layers while varying laterally, conformant with the differing anisotropy values of the different wells.

After construction of the new anisotropic volumes, vertical velocities were revised using the simple 1D VTI equation $V_{P0}^{new} = V_{P0}^{old}\sqrt{\frac{(1+2\delta^{old})}{(1+2\delta^{new})}}$ that preserves interval normal moveout velocity. At well locations in a 1D Earth, such a correction is expected to convert seismic velocities into well velocities while maintaining the same gather flatness. In laterally heterogeneous models, velocities can be expected to become closer to well velocities and also facilitate quicker convergence for subsequent tomography iterations that update vertical velocity only. In a final step, the model was converted into a new seismic image depth controlled by revised seismic vertical velocity. In this case study, it was done using a simple 1D transform to time using the initial velocity followed by conversion to depth using revised seismic vertical velocity.

Figure 4 contrasts Thomsen's δ volumes for the initial and calibrated models. In the initial model, anisotropy is low and its variation is parallel to the water bottom. By contrast, the calibrated model has higher anisotropy parameters that conform to subsurface structures. Figure 5 shows a cross-section of Thomsen's ε parameter, where one can see general conformance to picked seismic horizons with mild lateral variation between the wells. Initial validation of the new model was performed by ray-tracing through it and comparing the modelled travel times to the corresponding measured check-shot one-way times. It was observed that misfit was reduced in all analyzed wells compared to the initial model. Results for two of the representative wells are shown in Figure 6. Results from rapid beam migration using both models showed that, with the calibrated model, events moved up by as much as 600 ft, thus providing greatly improved well ties (Figure 7).

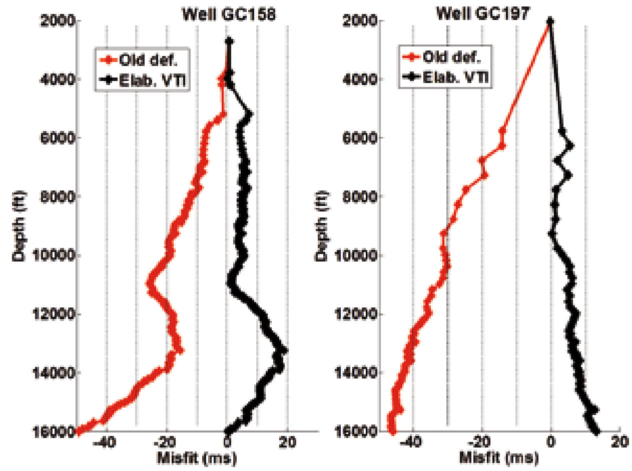

Figure 6 *Checkshot misfit in old and new models shown for wells GC158 (left) and GC197 (right). Misfit is a difference between ray traced in the model and experimental traveltimes. Note the reductions in misfit when switching to the new borehole-calibrated mode.*

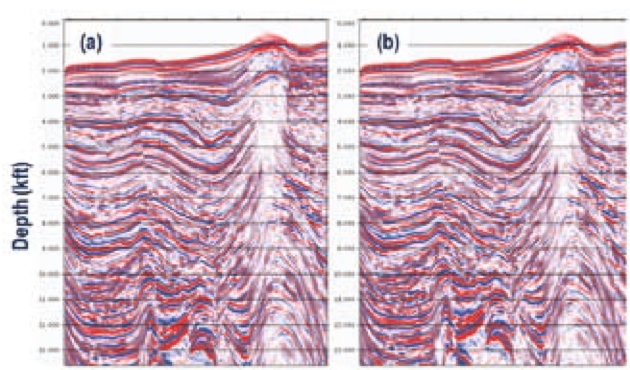

Figure 7 *Example results of Rapid Beam Migration using (a) initial model and (b) borehole-calibrated model. Note the general shift of reflections upwards, which led to improved well ties.*

An additional run of tomography is required to completely flatten gathers in complex areas because the simple 1D velocity correction performed during the workflow is not accurate in the case of steep dips. Improved focusing of events can be expected after this final update.

The methodology described above can be extended to TTI by defining two additional parameters that describe the tilt of the symmetry axis. These parameters can be derived from the seismic data and applied assuming structurally conformant transverse isotropy.

Conclusions

Derivation of anisotropy parameters from multiple wells and a horizon-guided approach to their interpolation can deliver more geologically plausible velocity models for imaging seismic data compared to a conventional approach that assumes a single smooth anisotropy profile hang from a shallow horizon. In a case study from the Gulf of Mexico, a VTI model using this workflow, and a layer-stripping inversion approach to deriving anisotropy profiles at 18 wells, yielded results that better tied seismic horizons to the well data. The technique can be used to build models for depth imaging on a large scale and can be extended to model TTI.

The described workflow is extendable to complex geological settings provided layer-stripping inversion is replaced by localized tomography with well data. Localized anisotropic tomography with well information can derive a local anisotropic model around deviated wells in the presence of dipping layers and TTI. Although improving well ties, the new workflow does not guarantee perfect well calibration. Tighter tolerance on fitting well data can be achieved by using uncertainty analysis to fine-tune the model to tie the wells within needed tolerance.

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