C038

Building Borehole-calibrated and Geologically Plausible Anisotropic Models Using Wells and Horizon-guided Interpolation

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SUMMARY

Universal adoption of anisotropic depth imaging places stronger focus on delivering quality anisotropic models that increase confidence in the depth positioning of seismic volume while also optimizing image quality. Calibration with well data such as checkshots or markers from one or several wells is becoming a must. Anisotropy determined around boreholes requires careful geologically-driven extrapolation between wells. We present a simple workflow that addresses both aspects. Borehole calibration step includes traveltime-preserved smoothing of the checkshots and deriving anisotropy profiles at wells by manual inversion or localized tomography. Then horizon-guided interpolation creates volumes of Thomsen parameters propagated consistently with the subsurface geology. Once new anisotropy volumes are derived, the entire velocity cube is revised to preserve normal moveout velocities. At the final step, the updated model is stretched into new seismic image depth. We present a case study that applies this workflow to wide-azimuth seismic data from the Gulf of Mexico where a VTI depth model is built for an area of 100 outer continental shelf (OCS) lease blocks using 18 wells with checkshots.

Introduction

Depth imaging with anisotropic velocity models has become a new industry standard. Vertical transverse isotropy (VTI) is one of the widely used types of anisotropic depth model. 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 we cannot rely on seismic tomography to derive multiple parameters in an entire volume because inversion of seismic data alone for all three parameters is highly non-unique (Tsvankin, 2001). Current industry practice consists of deriving a single smooth profile of Thomsen parameters ε and δ based on a limited well control in areas of flat-layered geology. This profile is propagated into an entire volume by simply hanging it off the water bottom or another shallow horizon. Then Thomsen parameters are kept fixed whereas velocity along the symmetry axis is updated by tomographic inversion of reflection seismic data (Woodward et al., 2008). Such a practice represents an improvement compared to isotropic models used in the past, but suffers from a series of limitations:

- Use of a single anisotropy profile disregards lateral variation of anisotropy in the subsurface;
- This single anisotropy profile is overly smoothed in the vertical direction because finer details cannot be accurately propagated in a 3D volume with complex geology;
- Structure of anisotropic volumes follows water-bottom topography but not subsurface geology.

The objective of this study is to describe a simple new workflow that overcomes these limitations.

Building an extensive anisotropic model with data from multiple wells

We assume that several wells are available with some measurements suitable for velocity model building (checkshot, VSP, markers, sonic logs). The aim is to build VTI depth model that fits all well data as well as existing seismic data. At a high level new workflow consists of three major steps: (1) derive local anisotropy profiles/models around existing wells; (2) pick set of key seismic horizons; (3) populate volumes of anisotropic parameters using horizon-guided interpolation of anisotropic profiles derived at wells.

Deriving local anisotropy profiles at the 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, only profiles of anisotropic parameters along the wells are kept as the sole deliverable of the first step. Horizons are picked at the second step to guide the propagation of anisotropic properties between the wells. The third step of interpolating anisotropic parameters between the well is broken into four sub-steps:

- Convert anisotropy profiles (along the wells) from well depth to seismic image depth;
- Interpolate anisotropy profiles between wells in seismic image depth;
- Update vertical velocity in a volume to maintain the same normal moveout velocity;
- Transformation to a new seismic image depth.

The first sub-step is required to bring the anisotropy profiles derived in “well depth” to “seismic image depth” where horizons are derived. After interpolation and velocity update, model is converted to “new seismic image depth” controlled by updated velocity. In the examples below, it is implemented as a simple vertical stretch.

Case study from Green Canyon, Gulf of Mexico

Let us demonstrate application of a new workflow using a case study from the northern part of Green Canyon, Gulf of Mexico. The wide-azimuth seismic data consists of 100 OCS blocks; whereas, the well data is represented by 18 wells with checkshots selected in areas of near-zero dip. For each borehole, vertical well velocity was 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 velocity and ensures that there is no bias that may distort time-depth conversion (Figure 1). However, we deliberately exclude some high-frequency details that are not appropriate for a macro velocity model. In this study, we opted to perform local 1D manual layer-stripping inversion at each well location where we fixed the velocity to smoothed checkshot velocity and then derived profiles of Thomsen's ε and δ. Common-image point (CIP) gathers are flat for the both initial and derived models (Figure 2a,b); however the borehole-calibrated model has velocity equal to well velocity and larger anisotropy profiles that, in addition, suggest the presence of shallow layers with higher anisotropy that were not included in the initial model (Figure 2c). As a result, all seismic events moved upwards.

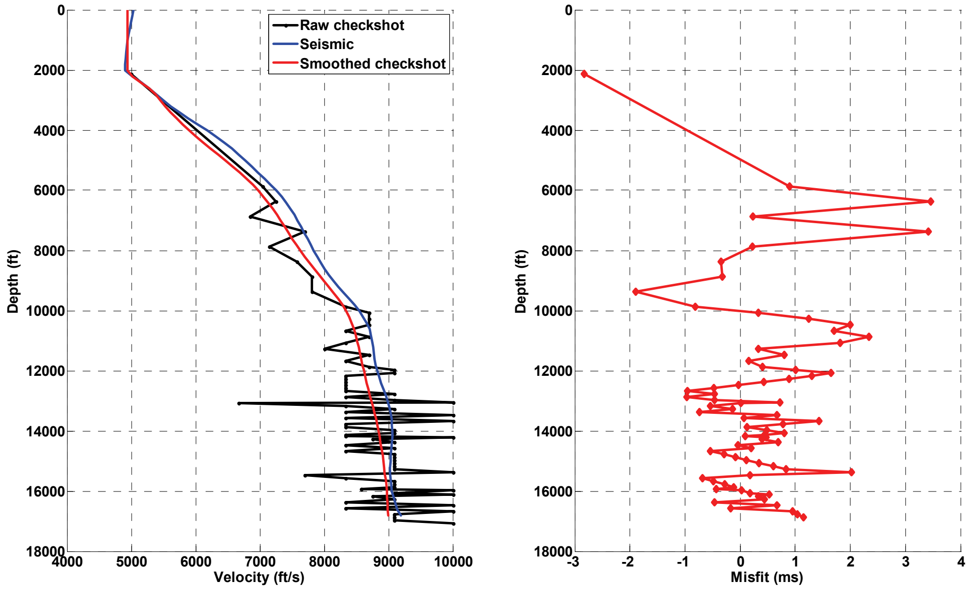

Figure 1 *(a) Velocity profiles at the well location showing the initial seismic model derived with tomography, raw checkshot velocity, and smoothed checkshot velocity; (b) traveltime residuals for smoothed checkshot velocity profile.*

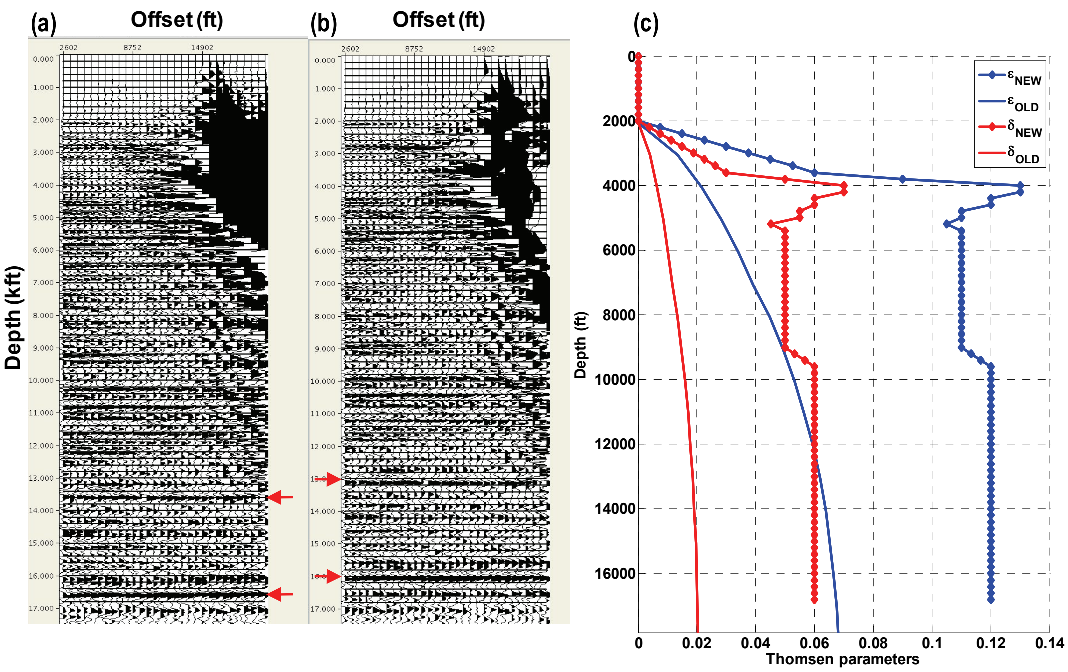

Figure 2 *Common-image point gathers for initial (a) and 1D model (b), derived from 1D manual layer-stripping inversion at the well location; (c) profiles of Thomsen parameter for initial (solid lines) and derived model (solid lines with circles). Note upward movement of seismic horizons shown by red arrows.*

Before interpolation, anisotropic profiles are converted to an old seismic image depth. In this study, we used simple 1D conversion by first converting them to time using well velocity followed by conversion to depth using seismic vertical velocity in the initial model. In the next step, Thomsen parameters from 18 wells are propagated into the entire volume using horizon-guided interpolation with seven horizons. For each layer, top and bottom surfaces are used as a guide; thus by design, anisotropy generally conforms to layers, whereas it varies laterally if anisotropy values differ in different wells.

Once new anisotropic volumes are constructed, we also revise the vertical velocity using the simple 1D 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 velocity into well velocity while maintaining the same gather flatness. In laterally heterogeneous models, we expect velocity to become closer to a well velocity and also facilitate quicker convergence for subsequent tomography iterations that update vertical velocity only. In a final step, we convert the model 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 initial velocity followed by conversion to depth using revised seismic vertical velocity. Figure 3 contrasts Thomsen's δ volumes for initial and calibrated models. In the initial model, anisotropy is low and its variation is parallel to the water bottom. In contrast, the calibrated model has higher anisotropy that conforms to subsurface structures. Figure 4 shows a cross-section of Thomsen's ε parameter, where one can see general conformance to a picked seismic horizons with a mild lateral variation between the wells. Rapid Beam Migration with the calibrated model reveals that events move up by as much as 600 ft, thus greatly reducing well misties (Figure 5).

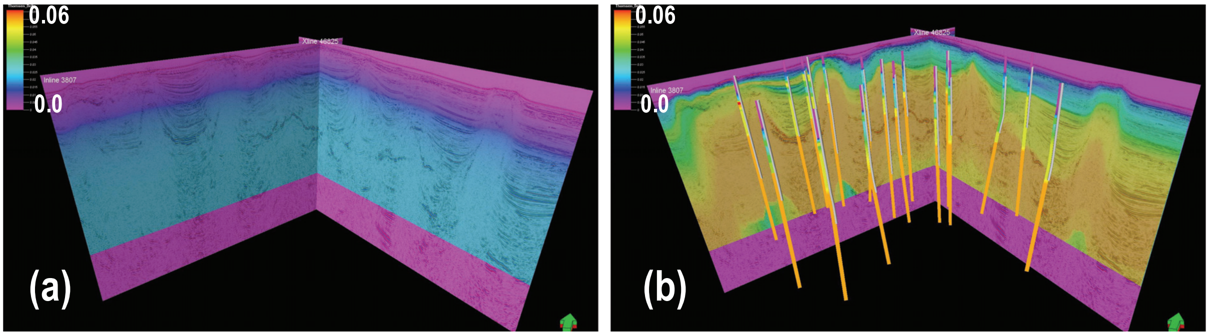

Figure 3 *Thomsen's δ volume for (a) initial model and (b) final calibrated model. Tracks of 18 wells are shown together with the corresponding Thomsen's δ profiles shown as logs along the wells.*

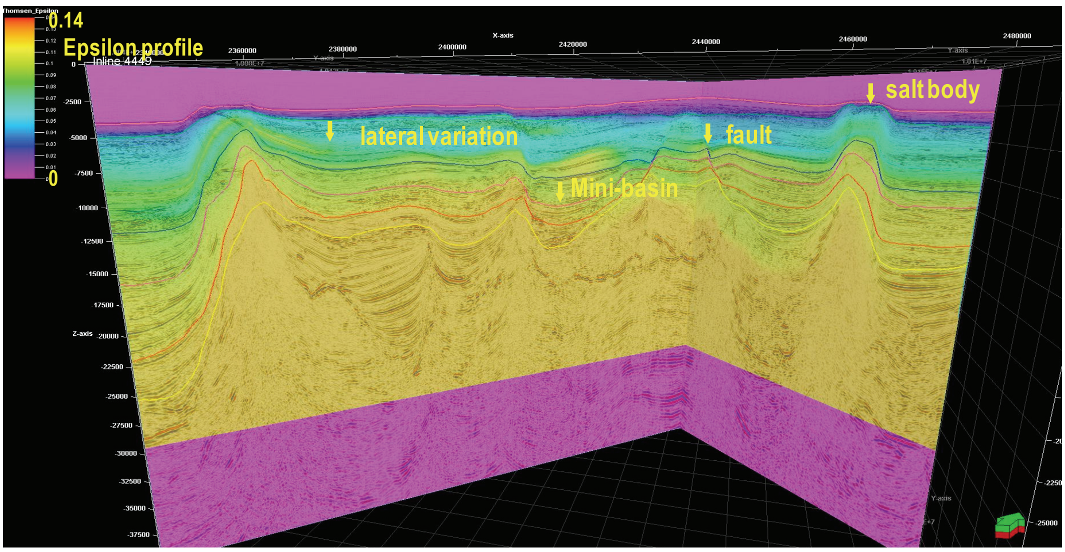

Figure 4 *Cross-sections through a Thomsen's ε volume for newly constructed borehole-calibrated model. Lines show interpreted horizons used for interpolation of Thomsen parameters.*

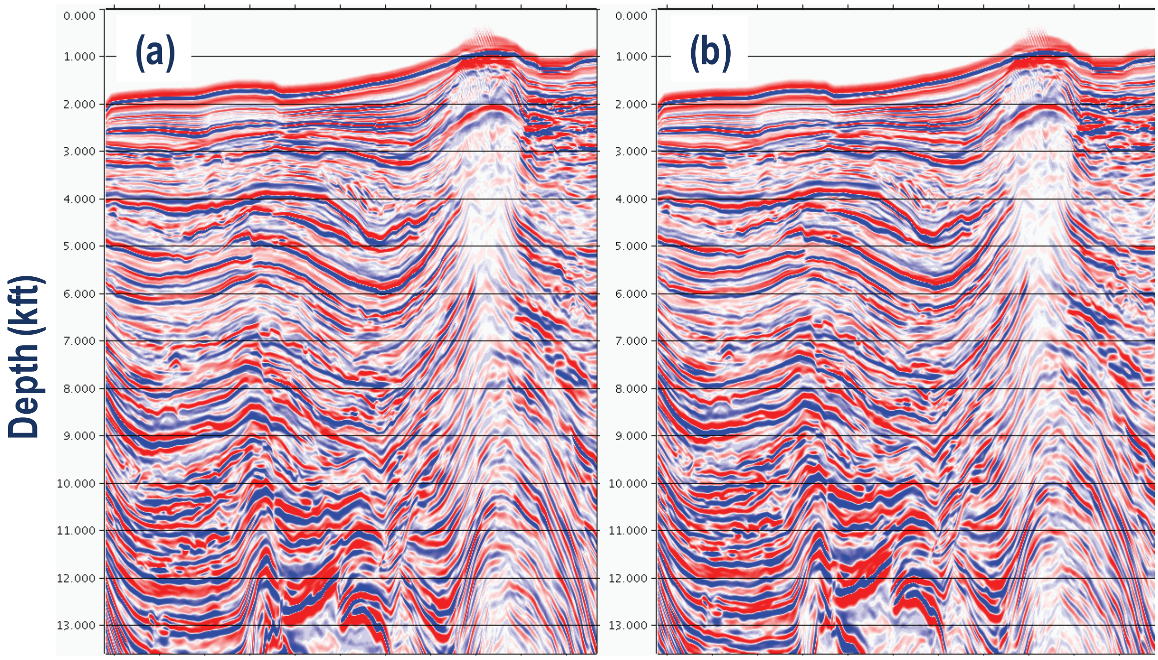

Figure 5 *Images obtained by Rapid Beam Migration using (a) initial model and (b) borehole-calibrated model constructed with described workflow. Note general shift upwards increasing with depth in the new image. Such a shift greatly improves well ties.*

An additional run of tomography is required to completely flatten the gathers in complex areas because a simple 1D velocity correction performed during the workflow is not accurate in the case of steep dips. We expect improved focusing of events after this final update and such validation is in progress.

Conclusions

We have presented a simple workflow that allows building more geologically plausible anisotropic depth models and incorporation of all well data in the area of interest. We presented a case from Gulf of Mexico where we constructed a VTI model for an area of 100 OCS block using wide-azimuth seismic data and 18 wells with checkshots. In the presented case study, we have used 1D manual layer stripping inversion around wells, therefore, restricting us to use vertical wells in areas of mostly flat dips. 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 overcome the above limitations and derive a local anisotropic model around deviated wells in the presence of dipping layers and tilted transverse isotropy.

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