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Characterization of the unconventional and carbon sequestrated reservoirs- the new challenges to the prestack waveform inversion

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Summary

As the production from the conventional reservoirs are nearing its peak and it is expected that not much in-place oil/gas will be discovered from these reservoirs in future, the primary focus of the oil and the gas industry is now shifting to exploring the unconventional reservoirs. Additionally, since fossil fuels are expected to be the major source of energy, at least for the next 10 to 20 years, it is important that the carbon dioxide (CO_2) and the other greenhouse gases emitted into the atmosphere from burning these fossil fuels be captured and sequestrated into the deep saline aquifers underground. Such carbon sequestration is by no means complete unless the sequestrated formations are remotely monitored using geophysical tools to ensure that the injected gas is in place and does not disturb the geological integrity of the surrounding rocks. Both exploring the unconventional and monitoring the carbon sequestrated reservoirs using seismic data offer a unique, but a similar set of challenges to the geoscientists. They both require a detailed subsurface lithology/fluid and geomechanical model and they both demand a thorough understanding of seismic wave propagation in anisotropic elastic medium. Since the classical amplitude-variation- with-offset (AVO) inversion is ambiguous in the presence of anisotropy, it is mandatory that we use a prestack waveform inversion (PWI) that not only can extract detailed subsurface anisotropic earth models but it also can relate them to the subsurface lithology/fluid and geomechanical properties.

Introduction

Exploring and characterizing unconventional reservoirs and Characterizing and monitoring carbon sequestrated reservoirs offer new, but very similar set of challenges. In unconventional reservoirs, for example shale gas/oil, it is crucial to use seismic data to characterize the formation and delineate oil/gas accumulations. Once these zones are successfully located, the formation must then be hydraulically fractured for production. Optimum placement of these fractures requires a thorough understanding of the geomechanical properties of the field, such as the orientation and magnitude of current maximum and minimum horizontal subsurface stress fields over the entire area of interest (Starr, 2011). Additionally, most shale formations are inherently anisotropic, in particular, transversely isotropic with a vertical symmetry axis (VTI). On top of this VTI anisotropy, most shale oil/gas reservoirs are also naturally fractured, and such a fractured VTI rock will be azimuthally anisotropic with orthorhombic symmetry (Schoenberg and Douma, 1988).

For carbon sequestrated reservoirs, after CO_2 is sequestrated into the formation, over a period of time the imbibition process caused by the capillary action in between the pore spaces (Juanes et al, 2006), gives rise to a patchy saturation, which could be modeled by an equivalent anisotropic medium (Behzadi et al, 2011; Padhi et al, 2011). Also, the frame moduli change due to chemical reaction and porosity changes from CO_2 sequestration gives rise to frequency-dependent elastic properties with frequency-dependent shear wave splitting (Ghosh and Sen, 2011). Additionally, characterizing and monitoring carbon sequestrated reservoirs requires a detailed analysis of the overlying formations for their seal properties, and because above normal pore pressure due to sequestration may fracture these overlying formations, which, in turn, could become possible pathways for leakage, it is important to understand their geomechanical properties so that fractures could be avoided during sequestration.

To properly characterize carbon sequestrated and unconventional reservoirs, it is therefore important to go past the concepts of isotropy and consider anisotropic effects of seismic wave propagation. Not only we want to extract the subsurface anisotropic properties from data, but we would also like to relate them to the subsurface lithological, fluid, and geomechanical properties. While for unconventional reservoirs geomechanical properties are needed to fracture the formation for production optimization, for carbon sequestrated formations they are needed to avoid fracturing of the overlying formation during the post-sequestration phase.

Technical Background

The current state of the art for characterizing the conventional reservoirs is to use AVO analysis and inversion and it is therefore important to first consider if it is possible to extend the AVO inversion to anisotropic media. Below, we will address the AVO inversion for primary (P-P) reflections. A detailed discussion of AVO analysis and inversion using both primary and mode- converted (P-SV) reflections in an azimuthally anisotropic medium can be found in Mallick et al (2005). Linearized approximation to the plane-wave P-P reflection coefficient from an interface separating rocks with varying elastic properties is given as (Aki and Richards, 1980)

$$R_{PP} \approx A + B\sin^2\theta + C\sin^2\theta\tan^2\theta. \qquad (1)$$

In equation 1, R_{PP} is the P-wave reflection coefficient as a function of the angle of incidence θ. The terms A, B, and C on the right hand side of equation 1 are known respectively as the AVO intercept, AVO gradient, and AVO curvature. Assuming an isotropic earth, they can be expressed explicitly in terms of the elastic properties and density (see Aki and Richards, 1980 for details) as

$$\begin{aligned} A &\approx \frac{1}{2}\left(\frac{\Delta\alpha}{\alpha} + \frac{\Delta\rho}{\rho}\right), \\ B &= \frac{1}{2}\frac{\Delta\alpha}{\alpha} - 2\left(\frac{\beta^2}{\alpha^2}\right)\left(2\frac{\Delta\beta}{\beta} + \frac{\Delta\rho}{\rho}\right), \\ C &= \frac{1}{2}\frac{\Delta\alpha}{\alpha}. \end{aligned} \qquad (2)$$

In equation 2, α, β, and ρ denote respectively the average P-wave velocity, average S-wave velocity, and average density and $\Delta\alpha$, $\Delta\beta$, and $\Delta\rho$ are their respective contrasts across the reflecting interface. AVO inversion methods are primarily based on equations 1 and 2, and involve the following steps:

1. Correct prestack seismic data, recorded in offset and time for normal moveout (NMO) and convert NMO corrected data in offset and time into angle-of-incidence (θ) and time by partially stacking the offset domain data along constant incidence-angle trajectories .
2. To each reflection in the angle-domain data from step 1, fit equation 1 to extract A, B, and C.
3. Use equation 2 to calculate the P- and S- velocity and the density reflectivity contrasts ($\Delta\alpha/\alpha$, $\Delta\beta/\beta\Delta\rho/\rho$) from the estimates of A, B, and C for each reflection on data, obtained from step 2.
4. Use the a-priori knowledge of the background (low frequency) velocity and density information and convert the reflectivity contrasts obtained from step 3 into absolute values of P- and S-wave velocity (α, β) and density (ρ).

Although quite simple and straightforward, AVO inversion applied to the conventional reservoirs has so far been quite successful, particularly in detecting the presence of gas. Because S-waves are not sensitive to the presence of fluids in the formation while P-waves and density are, presence of gas results in an abrupt drop in density and P-to-S-wave velocity ratio (α/β) or the Poisson's ratio. AVO inversion methods utilize this fundamental property for direct detection of hydrocarbons from seismic data.

Isotropic AVO equations (equations 1 and 2) have also been applied for characterizing the Marcellus shale-gas reservoir with some limited success (Koesoemadinata et al, 2011). Koesoemadinata et al (2011) also claim that the zones of high Poisson's ratio from AVO inversionrepresent ductile behavior in the rocks which should be avoided for drilling and fracturing. Starr (2011) demonstrated how the Poisson's ratio could be effectively used in determining the direction and magnitudes of the minimum horizontal stress under the assumption of an isotropic rock behavior and uniaxial compression. It must however be noted that shale formations are inherentlyanisotropic with VTI symmetry. For example, Marcellus shale gas reservoir is VTI and on top of that it is naturally fractured (Gaiser et al, 2011). Seismically, a fractured rock with VTI background should behave like a medium with orthorhombic symmetry having nine independent elastic constants (Schoenberg and Douma, 1988). Such a medium is azimuthally anisotropic, meaning that we expect to see different AVO behavior for different source-to-receiver azimuths. Approximate AVO equation (equation 1) is still valid for such azimuthally anisotropic medium, but the AVO gradient (*B*) and AVO curvature (*C*) terms in equation 1 become functions of the azimuth φ and are given as (Rüger, 1998)

$$B = \frac{1}{2}\frac{\Delta\alpha}{\alpha} - 2\left(\frac{\beta^2}{\alpha^2}\right)\left(2\frac{\Delta\beta}{\beta} + \frac{\Delta\rho}{\rho}\right) + \left[\frac{\Delta\delta^{(V)}}{2} + 4\left(\frac{\beta^2}{\alpha^2}\right)\Delta\gamma\right]\cos^2\varphi,$$
$$C = \frac{1}{2}\frac{\Delta\alpha}{\alpha} + \left(\frac{\Delta\varepsilon^{(V)}}{2}\sin^2\varphi\cos^2\varphi + \frac{\Delta\delta^{(V)}}{2}\cos^4\varphi\right). \qquad (3)$$

Notice that when the medium is azimuthally anisotropic, the P- and S-wave velocities vary with the angle-of-incidence (θ) and the azimuth (φ). The P- and S-wave velocities (α and β) in equation 3 are now the velocities at normal incidence (θ=0°). The parameters $\varepsilon^{(V)}$, $\delta^{(V)}$, and γ are the Thomsen-Tsvankin parameters (Thomsen, 1986; Tsvankin, 1997), which can be expressed in terms of the elastic constants as

$$\varepsilon^{(V)} = \frac{C_{11} - C_{33}}{2C_{33}},$$
$$\delta^{(V)} = \frac{(C_{13} + C_{55})^2 - (C_{33} - C_{55})^2}{2C_{33}(C_{33} - C_{55})}, \qquad (4)$$
$$\gamma = \frac{C_{66} - C_{44}}{2C_{44}}.$$

It can be readily seen from equation 3 that the classical isotropic AVO methods will not work for anisotropic medium. Although we can sort prestack seismic data into different source-receiver azimuths and fit equation 1 to extract *A*, *B*, and *C*, the fact that the anisotropic parameters $\varepsilon^{(V)}$, $\delta^{(V)}$, and γ are coupled with vertical P and S velocities (α, β) and density (ρ) in the AVO gradient (*B*) and AVO curvature (*C*) terms makes it practically impossible to extract the individual elastic properties and densities from anisotropic azimuthal AVO analysis unless prior assumptions are made regarding their inter-dependence with one another. Additionally, as noted in step 1 above, offset-to-angle transform involves two fundamental steps, (1) correct offset domain data for NMO, and (2) partially stack the NMO corrected data along the constant angle trajectories to convert offset into angles. NMO equation for anisotropic medium is given by Alkhalifah (1997). Although this anisotropic NMO works for small offsets, its accuracy rapidly deteriorates at large offsets (Mallick, 2008). Computation of the angle-of-incidence for converting offsets into angles is controlled by the velocity fields extracted from seismic data. These velocity fields, in turn, are controlled by the traveltimes of different reflection events, which are in fact the velocity along which the energy propagates and are therefore the energy or group velocities and the angles extracted using these velocities are group angles. The reflection coefficients on the other hand, are functions of phase angle not the group angle. As shown in Figure 1, plane waves with a given phase angle θ propagate outward from the source with a given slowness or inverse velocity vector (**p**). Slowness vectors with different phase angles form a surface, known as the slowness or inverse velocity surface, a two dimensional cross section of which is shown in Figure 1. From any point on the slowness surface, the energy propagates along the direction normal to the slowness surface. As shown in Figure 1, for a slowness vector **p** with phase angle θ, the group velocity vector $\mathbf{v_g}$ is directed along the normal to the slowness surface with a magnitude given by the reciprocal of the component of **p** along the normal, i.e.,

$$\mathbf{v}_g = \frac{\hat{\mathbf{n}}}{\hat{\mathbf{n}}.\mathbf{p}}. \qquad (5)$$

The angle made by the group velocity vector $\mathbf{v_g}$ with the vertical is the group angle ϕ (see Figure 1). In a perfectly isotropic world, where the slowness surface is a sphere, the group velocity vector is directed along the direction of the slowness vector and the distinction between the group and the phase angles is not necessary. This is however not true when the medium is anisotropic. The angles extracted from the data are always group angles while the approximate AVO equation 1 is given in terms of phase angles, and before making any quantitative interpretation of AVO results, group angles must first be converted to their equivalent phase angles.

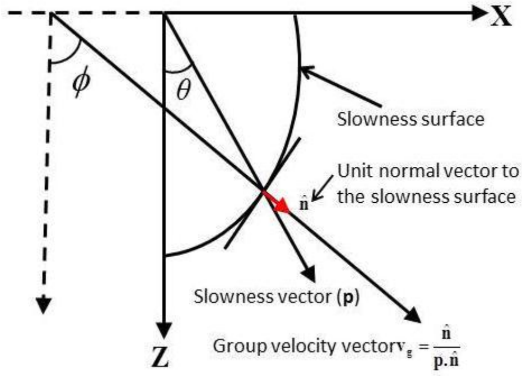

Figure 1: Schematic diagram showing the slowness surface, slowness vector (**p**), phase angle (θ), group velocity vector $\mathbf{v_g}$ and group angle (ϕ) in an anisotropic medium.

To correctly analyze seismic data in presence of anisotropy, as is the case for exploring and characterizing unconventional and carbon sequestrated reservoirs, it is necessary to go past AVO and utilize advanced concepts that will allow us to understand the exact nature of seismic wave propagation in an anisotropic medium. Prestack waveform inversion (PWI) that goes a step beyond AVO allowing us to model all complex effects of seismic waves on the recorded seismic data is a rapidly emerging, and we believe that an anisotropic PWI is the correct approach for characterizing the unconventional and carbon sequestrated reservoirs. Because extracting subsurface anisotropic properties requires full-wavefield data, it is mandatory that we record 3D/3C seismic data and the anisotropic PWI is a multicomponent inversion methodology.

To accurately convert the NMO uncorrected offset data into angles in the presence of anisotropy, a ray-based approach is already in place (Mukhopadhyay and Mallick, 2011a, b) Figures 2 and 3 show an example of this new offset-to-angle transform for a realistic VTI model compared with a conventional transform that is currently practiced by the oil and gas industry.

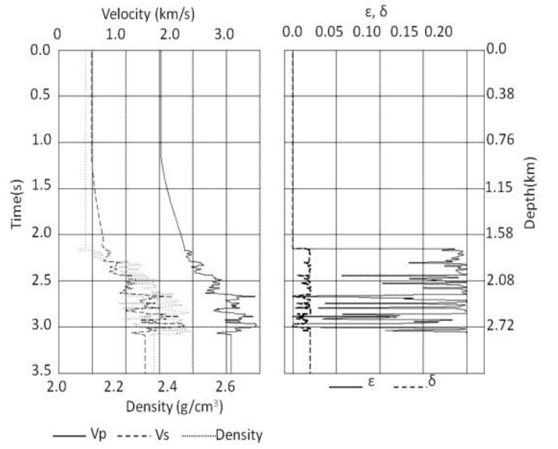

Figure 2: A VTI model extracted from a real well log and anisotropic velocity analysis of real seismic data.

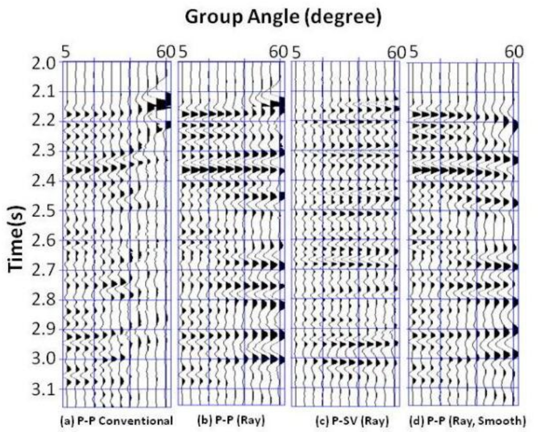

Figure 3: Offset-to-angle transform from the offset domain synthetic seismic data computed using the model shown in Figure 2. (a) Conventional P-P angle gather computed by NMO correcting the offset gather using Alkhalifah (1997) equation and then partially stacking the NMO corrected offset traces over their respective constant angle trajectories. (b) P-P angle gather computed using the ray- based approach. (c) Mode-converted (P-SV) angle gather computed using the ray-based approach. (d) Same as (b) where a smooth model instead of the true one is used in ray tracing for computing the ray-based P-P angle gather.

Several inferences could be drawn from the offset-to-angle transform example shown in Figure 3:

1. It goes without saying that the ray-based transform is much superior to the conventional transform. Reflection events in the angle gathers, if

computed correctly should be flat. Not only the events in the conventional gather (Figure 3a) are not flat, except for angles less than 15°, but they also tend to disappear for angles larger than 40°. The ray-based gather on the other hand shows flat and consistent reflections out to large angles.

2. The ray-based method allows offset-to-angle transform not only for P-P gathers, but also for P-SV gathers.
3. The ray tracing allows the P-SV gathers to be displayed in two-way P-wave time. The P-SV angle gather shown in Figure 3c is in P-P time not in P-SV time. This, in turn, allows an easy joint interpretation of primary and mode- converted reflections. Additionally, it should potentially let us extract both P- and S-velocity models and other anisotropic parameters in an iterative multicomponent seismic inversion scheme without any need for event registration.
4. The fact that using a smooth model instead of the exact one does not produce as flat of a response as using the exact model (compare Figures 3b and 3d) means that the travel-time contains valuable information that could be effectively utilized in constraining the initial model in seismic waveform inversion.
   a. Notice in Figure 3d, the P-P angle gather reflections are not flat up to about 2.6s, they are then relatively flat between 2.6-2.8s, and again they are not flat below 2.8s.
   b. Now notice from the model shown in Figure 2, the anisotropy is strong up to 2.6s, relatively weak between 2.6-2.8s and is strong again beyond 2.8s.
   c. Our ray-based transform is therefore sensitive to the anisotropy parameters.

Ray-based transform is therefore a big step forward from the conventional transform and we think that it could be effectively utilized in constraining the initial anisotropic model in a multicomponent PWI which could potentially remove the ambiguities that are inherent to an anisotropic AVO inversion.

The primary challenge in characterizing the unconventional and carbon-sequestrated reservoirs is to effectively relate the anisotropic parameters from seismic inversion to the subsurface lithology, fluid, and geomechanical properties. To get a geomechanical model, it is necessary to have detailed understanding of in situ stress orientations, in situ stress magnitudes, pore pressure, unconfined compressive strength, and rock properties such as cohesion, friction and elastic moduli (Zoback, 2010). Our primary challenge here is to evaluate the geomechanical properties from such geological and well data and relate them to seismic data so that seismic data could be utilized to predict properties at locations away from the well. Such a procedure under the assumptions of isotropy and uniaxial compression has been successfully utilized in the past in predicting geological hazards (Mallick and Dutta, 2002; Dutta, 2002) and in estimating the in-situ stress magnitudes (Starr, 2011). If however, we would like to go past the assumptions of isotropy and uniaxial compression, such calibration is challenging. For example, Figure 5 shows the ray based angle gathers for different source-to-receiver azimuths, extracted from real seismic data from the Rock Springs uplift (RSU). The angle gathers shown in Figure 5 are extracted from a location close to the RSU-1 well that has recently been completed. Notice that there is significant azimuthal variation in the reflection amplitudes in the data shown in Figure 5, especially for angles-of-incidence beyond 30°. While the variation of the average reflection amplitude as a function of angle-of-incidence is primarily controlled by the subsurface lithological and fluid properties, the variation of the reflection amplitude at a fixed angle of incidence as a function of the source-to-receiver azimuth is controlled by the orientations of the open fractures in the system, which, in turn, can be related to the in-situ maximum and minimum horizontal stress fields.

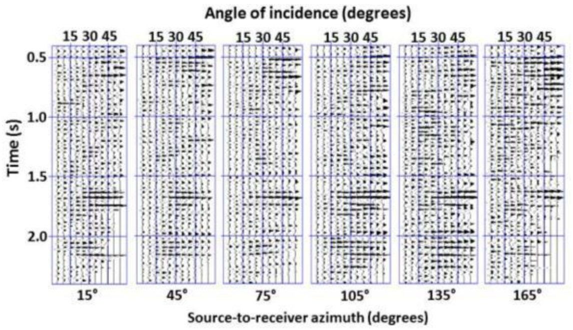

Figure 5: Azimuthal angle gathers extracted from RSU seismic data near the RSU-1 well location.

Mallick et al. (1998) demonstrated that the azimuthal amplitude variations, shown in Figure 5 could be locally fit to an ellipse to get the fracture orientation and a qualitative estimate of the fracture density, which in turn, could be related to the in-situ stress fields. Figure 6 is an estimate of such azimuthal analysis of the seismic data of Figure 5. Azimuthal analysis of seismic data, shown in Figure 6 can obtain open fracture patterns, which when calibrated with actual measurements from the well will allow fracture/stress field prediction over the entire 3D seismic data. It must however be noted that the analysis shown in Figures 5 and 6 is based on a P-wave azimuthal AVO analysis, which can only provide a qualitative estimate of the fracture/stress fields. For a quantitative analysis, both P- and converted wave data must be inverted in a multicomponent inversion methodology using an anisotropic PWI to extract anisotropic properties from data, which could then be used compute the magnitudes of the in-situ stress fields.

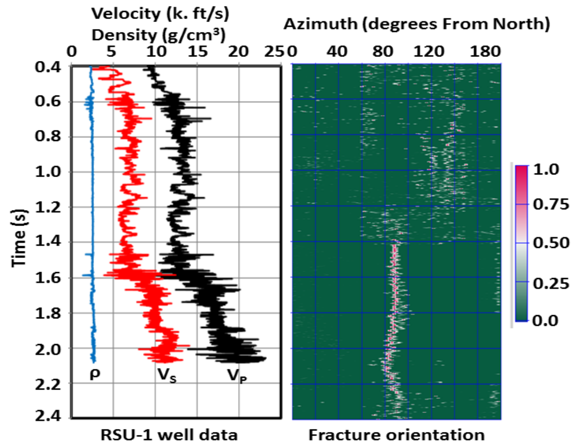

Figure 6: Fracture analysis using seismic data at the RSU-1 well location. The RSU-1 well data with the P-wave velocity (VP), S-wave velocity (VS) and density (ρ) are also displayed along with the computed fracture orientations. Notice the seismic analysis does not find any significant fracture pattern above 1.4s. There is, however a consistent E-W trending fracture pattern below 1.4s.

Conclusion

As the primary focus of the oil and gas industry is shifting from the conventional to the unconventional reservoirs, and reduction of greenhouse gas emissions from burning fossil fuels demands that they must be captured and sequestrated underground, the geoscientists are now faced with some unique set of challenges. Characterizing unconventional and monitoring carbon sequestrated reservoirs require subsurface lithology, pore fluid, and geomechanical properties to be extracted from seismic data. Since the classical seismic analysis techniques developed with isotropic assumptions are no longer valid in characterizing these reservoirs, development of an anisotropic PWI for multicomponent seismic data and relating the extracted properties from inversion to the geological and well information is a necessity. An anisotropic PWI methodology can potentially remove ambiguities associated with the AVO based methods, calibrated with the geological and well information, and can be effectively used to predict the required properties at locations away from the well-bore.

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