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Consistent imaging of hydraulic fracture treatments from permanent arrays using a calibrated velocity model

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SUMMARY

We developed a methodology to obtain a consistent velocity model from microseismicity observed within a permanent array. The inversion technique is based on visible microseismic events or calibration shots. Using a layered 1D isotropic model derived from checkshot data as an initial velocity model, we invert P-wave arrival times to obtain effective (constant) anisotropic parameters with vertical axis of symmetry (VTI). The nonlinear inversion iterates between anisotropic media parameters, origin times and depths for the microseismic events. We apply this technique to multiple events from several hydrofrac treatments within the array. The joint inversion results in a minimized RMS (~5 ms) indicating that we can obtain robust estimates of the anisotropic parameters. For joint inversion we obtained Thomsen anisotropy parameter ε of 0.15, and δ of 0.05, which is consistent with values observed from active seismic for the area. These results allow us to locate microseismic events distributed across tens of thousands of feet with a single velocity model. As a result, we have confidently inverted for effective anisotropy within the array and are able to provide more consistent microseismic mapping for past and future hydraulic fracture stimulations.

Introduction

Hydraulic fracture treatments are routinely optimized with microseismic monitoring (e.g., Duncan and Eisner, 2010 and Maxwell et.al. 2010). A new type of permanent array deployed with geophones in shallow boreholes (buried array) allows for consistent microseismic mapping for entire fracture programs at field scale. Calibration of this monitoring is dependent on a consistent velocity model. We developed a methodology to obtain a consistent velocity model with vertical axis of symmetry (VTI) from microseismicity observed on such a permanent array of sensors.

Seismic anisotropy is the dependence of seismic velocity upon wave direction (e.g., Thomsen, 1986) and has been used widely to improve reservoir imaging (e.g., Tsvankin and Grechka, 2006), litho-type discrimination (e.g., shales versus sands, e.g. Vernik, 2007), characterizing fractures and stresses (Prioul and Jocker, 2009), and monitoring the time-lapse changes of producing fields (Meersman et al. 2009). Current migration-based event location processing relies on a 1D isotropic approach utilizing P-wave stacking from vertical geophones with the majority of the velocity models derived from sonic logs, or alternately from VSP or checkshots. Such models usually do not locate calibration shot depth with sufficient accuracy. In this study we show that a VTI-type anisotropic model derived from 1D isotropic velocity function can locate calibration shots and microseismic events to correct depth. VTI is likely a reasonable model for a shale reservoir; which is consistent with Sayers (1993, 1994), who showed that shales can develop strong anelliptic anisotropy due to intrinsic textural properties.

In this case study, due to the significant depth of the stimulated shale reservoir no visible arrivals on individual receivers are observed from perforation or calibration shots. Therefore, we have developed an inversion technique based on visible microseismic events that are induced by hydraulic stimulation.

Methodology

We pick P-wave arrival times on receivers where we can observe distinct direct arrivals of direct P-waves. Our initial velocity model is a layered 1D isotropic model derived from an active surface seismic checkshot velocity taken in a nearly vertical well. The inversions of VTI parameters are dependent on the origin times and depths and vice versa. Thus we iterate between inversion for anisotropic parameters and the origin times of microseismic events while minimizing arrival time residuals

(1) Inversion Algorithm for VTI parameters

The compressional velocity can be calculated with $v_{P(\Theta=0)}$, which is the vertical velocity, and Θ is the dip angle between vertical axis and ray direction. The weak (ε , δ << 1) elastic VTI anisotropic qP-wave velocity can be approximated as (Thomsen, 1986):

$$v_P(\Theta) \approx v_{P(\Theta=0)} \left[1 + \delta \sin^2\Theta + (\varepsilon - \delta) \sin^4\Theta \right] .$$

Thus for approximate traveltime in layered weak VTI medium, it can be written as

$$T_P^{Ani} = \sum_{l=1}^{n} T_{P_l} = \sum_{l=1}^{n} \frac{x_l}{\alpha_l} - \delta \sum_{l=1}^{n} \frac{\sin^2\Theta_l}{\alpha_l} x_l - (\varepsilon - \delta) \sum_{l=1}^{n} \frac{\sin^4\Theta_l}{\alpha_l} x_l$$

$$= T_P^{Iso} + \delta A + (\varepsilon - \delta) B,$$

Where A=$-\sum_{l=1}^{n} \frac{\sin^2\Theta_l}{\alpha_l} x_l$; B=$-\sum_{l=1}^{n} \frac{\sin^4\Theta_l}{\alpha_l} x_l$,

and n is the number of layers. The location of jth microseismic event is defined from arrival times at all receivers $T_{P_{ij}}^{Pick}$, where i is the receiver index. The location is the position where these arrivals fit the traveltimes with minimum misfit. For each event minimized residuals R_{ij} can be written as

$$R_{ij} = T_{P_{ij}}^{Pick} - T_{P_{ij}}^{Ani} - T_{0_j} = T_{P_{ij}}^{Pick} - \delta A - (\varepsilon - \delta)B - T_{0_j} \ ,$$

In which T_{0_j} is the origin time for jth event. To minimize overall residuals $\sum_{j=1}^{m} \sum_{i=1}^{n} R_{ij}$ in least squares norm, we need to minimize

$$\sum_{j=1}^{m} \sum_{i=1}^{n} R_{ij}^{\ 2} = \sum_{j=1}^{m} \sum_{i=1}^{n} (-A_{ij}\delta - B_{ij}(\varepsilon - \delta) + C_{ij})^2 \ ,$$

where $C_{ij} = T_{P_{ij}}^{Pick} - T_{0_j}$. Thus we can rewrite the above as

$$\mathrm{d} = \mathrm{G} \cdot \mathrm{m} \ ,$$

where m=$[\delta; \varepsilon - \delta]$, G=$[-A, -B]$, and $d = \sum_{j=1}^{m} \sum_{i=1}^{n} R_{ij} - C_{ij}$.

This relation can be inverted by least square inversion of d analogously to VTI inversion of Bulant et al. (2007).

(2) Inversion for original times and depths

For microseismic events, and often even for string shots, the origin time is not known. For a given velocity model and depth we can calculate traveltimes $T_{P_{ij}}^{Ani}$ and compute least squares fitting origin time as $T_{0_j} = \sum_{i=1}^{n} (T_{P_{ij}}^{Pick} - T_{P_{ij}}^{Ani}) / Nrec$.

The flow chart describes searching for origin times when we do inversion and is displayed in the dash box (excluding the step of updating and searching for the depths) in Figure 1. However, for a microseismic event, the depth is unknown. In order to invert for depth simultaneously we iteratively grid-search for several depths above and below the last updated depth (and corresponding optimal origin times) in each step as shown in Figure 1. We search depths with origin time inversion for one event each time and use the updated depth to invert for new anisotropic parameters. The iteration terminates when overall RMS does not decrease significantly.

Case Study

We applied this technique to multiple microseismic events from several hydraulic fracture treatments within a buried array. The array consists of 100 stations and occupies approximately 25 square miles, with station offset spacing approximately 3000 ft. The geophones in each station are buried to 200-300 ft below the surface. The approximate depth of the stimulated shale is 12600 ft, resulting in maximum offset-to-depth ratio of 2. We applied the above described joint inversion to 8 high signal-to-noise microseismic events. The 8 events are from four different wells and the location distributions of the events are in the center and southern part of the array: wells with events number 1, 2, 3, 8 are located around the center of the array, and events number 4, 5, 6, 7 are located at the south edge of the array. The inversion resulted in reduced RMS misfit (averaged 4-7 milliseconds) indicating that we can obtain robust estimates of the anisotropic parameters. Table 1 shows results from the joint inversion of these 8 microseismic events resulting in Thomsen anisotropic parameter ε=0.15 and δ=0.05. These values appear to be robust over the number of events. We have also tested inversion without modifying initial depths of the microseismic events resulting in the same ε and slightly different δ (=0.06). In another test we set all initial depths to 12000 ft and obtained ε=0.16 and δ=0.07. This indicates that the reservoir model can be characterized with constant effective VTI parameters.

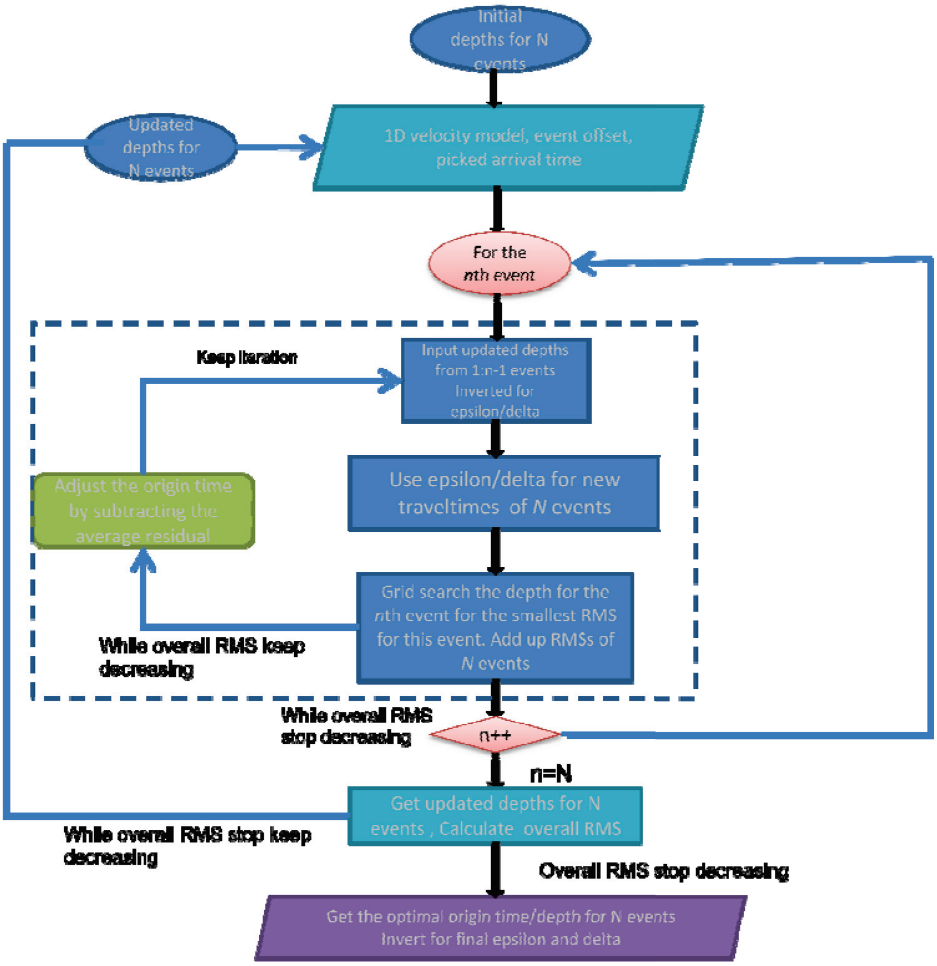

***Figure 1** Flow Chart for the inversion varying the origin time and the depth of N events*

Our algorithm also finds new depths of the microseismic events. We tested the algorithm with synthetic data and found that the inversion results for the depths are dependent on the choice of initial depth, which makes the result more uncertain. Therefore we constrain the depth search to 1000 ft from the depth of the treatment well and investigate the stability of the inverted VTI parameters. As discussed earlier, the inverted VTI anisotropic parameters ε, δ , do not seem to be severely affected by the different starting depths in our joint inversion of multiple events. In this case study, ε varies by 10% and δ varies by 25% from variation of event initial depths. Conclusively, the reservoir velocity model can be well approximated by a 1D VTI model.

As a result, with the inversion method, we have confidently inverted the effective anisotropy for the buried array region and we are able to locate microseismic events resulting from multiple hydraulic fracture stimulations with residuals less than 5 ms with a single velocity model.

Event	initial depth(ft)	Final Depth(ft)	epsilon	delta	RMS (seconds)	T0 (seconds)

Event1	11425	10825	0.1520	0.0612	0.0060	-0.0816
Event2	12592	11792			0.0046	-0.1042
Event3	12671	11671			0.0042	-0.0693
Event4	12960	13260			0.0054	-0.1436
Event5	12899	12399			0.0059	-0.0883
Event6	12678	12878			0.0042	-0.1199
Event7	12728	12728			0.0048	-0.1059
Event8	12895	12795			0.0082	-0.2055

Table 1 *Inversion results with depth searching*

Conclusions

We developed a methodology to invert for Thomsen VTI parameters in a 1D layered medium from P-wave arrival times of microseismic data recorded by a buried surface array. Our initial velocity model is isotropic and the Thomsen parameters are based purely on the inversionThe estimated values of the Thomsen parameters ε, δ will provide an anisotropic velocity model over the area of interest. This velocity model can be useful for effective seismic migration.

With the velocity profile and P-wave arrival times, we are able to recover the origin times and depths of the microseismic events with a single anisotropic model.

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