Effective VTI anisotropy for consistent monitoring of microseismic events

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The monitoring of induced or triggered microseismic events increasingly is being used to inform the efficient production of unconventional reservoirs. A key aspect of economic production in these low-permeability rocks is hydraulic fracture stimulation, usually in horizontal wells. To evaluate the success of the stimulation, engineers rely on monitoring the induced (or triggered) microseismic events that are then interpreted to map the stimulated reservoir volume and likely drainage area of the well. These microseismic events can be mapped either from downhole or surface monitoring arrays. In this study, we discuss a newly developed methodology that allows economic and consistent mapping of microseismic events from multiple stimulated wells across an entire field. This approach allows better comparison of stimulation techniques between wells in order to optimize long-term development of the reservoir. As well, the method enables a relatively robust observation of velocity anisotropy that leads to better wave-propagation modeling and more accurate event locations

Downhole arrays provide high signal-to-noise ratio data for events within 1500–3000 ft (500–1000 m) of the monitoring borehole (e.g., Maxwell et al., 2010). However, location accuracy as well as detectability strongly decay with distance from the downhole array (Eisner et al., 2009). Thus, it is hard to achieve consistent mapping of microseismic events over the entire length of a stimulated long lateral well let alone over an entire field. Surface monitoring using a larger areal array uses migration of the lower signal-to-noise data from a far larger number of receivers (tens of thousands of geophones) distributed in multiple azimuths and offsets. By their nature, surface monitoring arrays provide consistent imaging across large lateral well distances and multilateral well developments (Eisner et al., 2009, Chambers et al. 2010). Furthermore, the recent development of permanently installed near-surface arrays with geophones placed at 200–400 ft (75–130 m) below the surface in cemented, purpose-drilled boreholes allows consistent mapping of microseismic events not only in space but also over time, specifically spanning the time frame for reservoir development (Duncan and Eisner, 2010). Thus, these permanent arrays (also known as buried arrays) allow consistent comparison of numerous hydraulic fracture stimulations for many wells.

Accurate and consistent mapping of microseismic events over long time periods requires not only permanent monitoring arrays but also consistent velocity models used in the event-location technique. In this study, we show that anisotropy, and particularly VTI, is a key component in the development of such consistent models. A case study is presented where a simple layered vertically transverse isotropic (VTI) model allows successful positioning of multiple microseismic events from four hydraulic fracture stimulations that were several kilometers apart. To our knowledge, this is the first case study where multiple hydraulic fracture stimulations so far apart were mapped with a single velocity model.

This special section of *The Leading Edge* is focused on seismic anisotropy in sedimentary formations. While the majority of rocks tested in laboratories exhibit triclinic symmetry requiring 21 independent elastic constants at every point of a velocity model, a number of studies have shown that their anisotropy can be well approximated with higher-order symmetry systems (for a good overview, see Al-Harrasi et al., 2011). Therefore, in exploration seismology, we usually simplify the anisotropic properties of a rock formation using hexagonal symmetry (meaning the velocities are rotationally invariant around a single axis of symmetry). The orientation of the symmetry axis allows further classification into horizontal transverse isotropy (HTI) when the axis of symmetry is horizontal, vertical transverse isotropy (VTI) when the axis of symmetry is vertical, and tilted transverse isotropy (TTI) when the axis it tilted. HTI media are azimuthally anisotropic, whereas VTI media are azimuthally isotropic.

Case Study I

Microseismic monitoring with an array like that depicted in Figure 1 provides wide-azimuthal coverage and allows determination of the orientation of the anisotropic axis of symmetry. The data used to perform this determination are P-wave

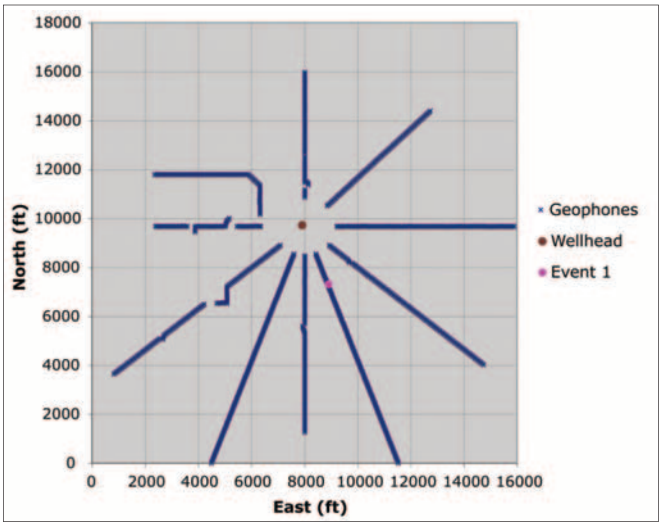

Figure 1. *Map showing geophone distribution for Case Study 1. Each line consisted of 50–150 vertical-component geophones (deployed at the surface) which are represented by blue crosses. The well location in the center of the lines is represented by the brown dot. The pink dot represents the epicenter (map view projection of the location) of a microseismic event.*

arrivals from a microseismic event (pink dot in Figure 1) induced by a hydraulic fracture stimulation of the reservoir beneath the array. This event was sufficiently strong to show high-amplitude P-wave arrivals on a majority of the receivers shown in Figure 1. The event is approximately 7000 ft deep, close to the location of a perforation shot which had similar, although somewhat weaker, signal. Thus, we are reasonably confident in the lateral positioning of the microseismic event (owing to its proximity to the perforation shot used for calibration).

Figure 2 shows manually picked arrival times from all 10 receiver lines shown in Figure 1. The range of the vertical axis (arrival times) is arbitrary as the origin time is unknown in passive seismic (origin time is time of microseismic event occurrence). The horizontal axis in the plot is dip angle assuming a straight ray connecting the event and receiver. We know this is not the true dip of the take-off angle as the medium is stratified but it allows us to quantify azimuthal isotropy of the arrival times. The spectra of P-wave arrivals in particle velocities peak between 20 and 30 Hz (Gei et al.). The amplitude spectra are above one half of the peak value from 5–8 Hz up to 40–50 Hz on most receivers. The similarity of moveout with angle at all azimuths indicates that arrival times are controlled by an approximately 1D flat-layered structure with a vertical axis of symmetry. This is further confirmed by the right plot in Figure 2 where differential arrival times relative to receiver line 10 show differences smaller than 20 ms along the whole profile without a systematic variation. Thus, we conclude that the P-wave arrivals do not show a strong evidence of HTI or TTI symmetry. Rather, VTI symmetry is a good representation of this reservoir rock. This observation has held true in other shales we have tested.

Considering that the traveltime to the far offsets is approximately 1 s, the maximum apparent strength of the TTI or HTI anisotropy is limited to 4% as the largest arrival times in Figure 2 differ at most by 0.04 s (and we sample take-off angles in multiple, >10, azimuths with dips up to 60°). This is much smaller value than the VTI strength found by Gei et al. who estimate effective (average) VTI in this reservoir through inversion of P-wave arrivals to be close to 24% (with η = 0.26 and Thomsen's parameter δ = 0.11). Furthermore, this HTI or TTI anisotropy would suggest orientation of maximum horizontal stress in a northwest direction which is nearly perpendicular to the direction measured by other techniques in this region. Thus, we conclude that the broad coverage of surface receivers allows us to estimate the orientation of axis of symmetry for an effective anisotropic media and this axis is predominantly vertical. Such an observation may seem contradictory to the observations made by Verdon et al. (2009) or Al-Harrasi et al. who observed a combination of VTI and HTI anisotropy from passive seismic data by inverting S-wave splitting from borehole data sets. Beside the fact that these observations were made in other reservoirs, the surface observations are more sensitive to reservoir overburden probably dominated by VTI while downhole observations, are sensitive to reservoir layers which might be more affected by local fracturing or stress.

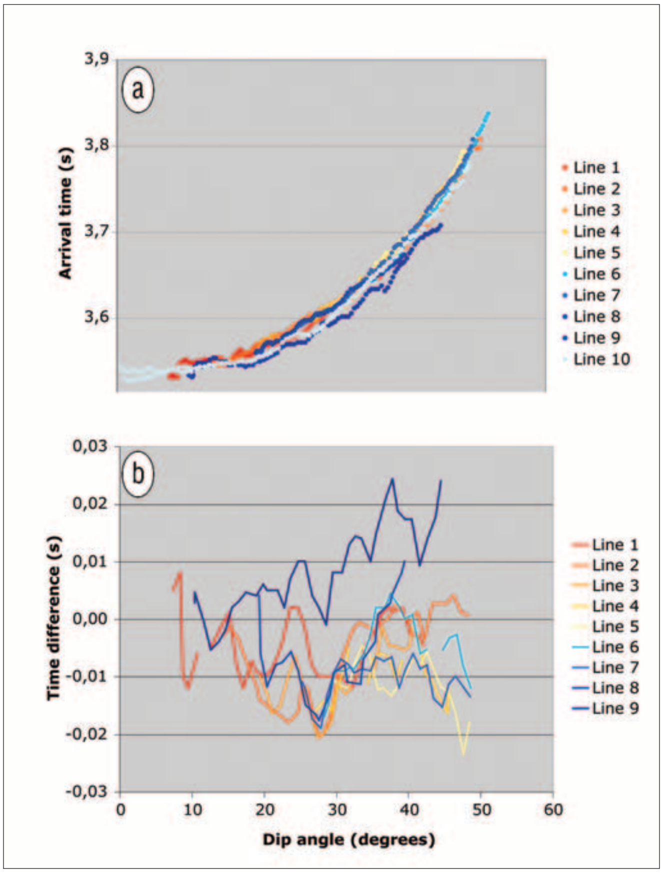

Figure 2. Arrival-time picks for event 1 for all 10 lines in Figure 1 (a) and (b) differential times (i.e., arrival times of nine lines subtracted from arrival times of the tenth line, with the same dip angles). The dip angle is defined by the direction of a straight ray between event 1 and the receiver.

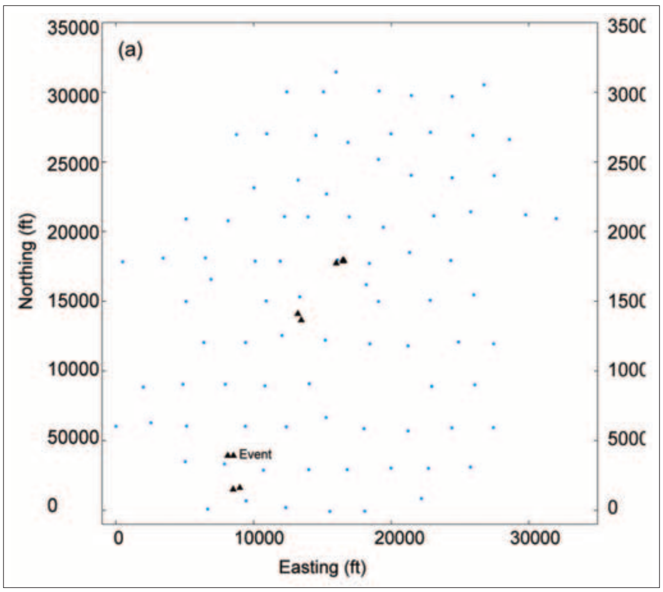

Figure 3. Map view of the buried array stations (blue dots) and epicenters of the located microseismic events (black triangles). The 3C geophones were deployed in purpose-drilled boreholes to depths between 200 and 300 ft (75–100 m). The boreholes were cemented and filled up to prevent contamination by tube waves. Microseismic events were located in depths between 11,000 and 13,000 ft (3300–4000 m).

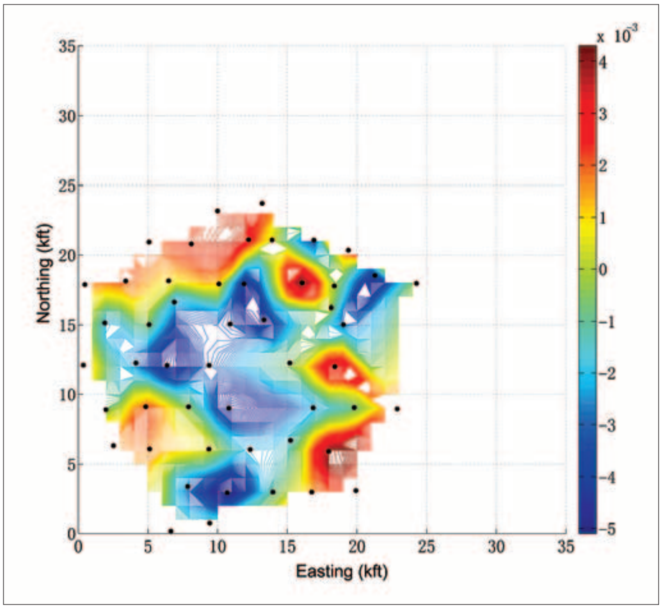

Figure 4. Map of residuals between calculated and picked arrival times after joint inversion for VTI anisotropic model and locations of microseismic events (depth). The residuals correspond to an event from the southern portion of the array in Figure 3.

Case Study II

Zhang et al. (2011) developed a methodology of inversion for VTI parameters using a 1D layered model and P-wave arrivals from strong microseismic events (either calibration shots or microearthquakes). They apply the methodology to a buried array data set using observations from four different stimulations separated by more than 20,000 ft (6800 m). Figure 3 shows a map view of the buried geophones and the location of the eight microseismic events used in this study. Note that approximately 100 stations are distributed over a rather large area spanning 30,000 ft (9800 m) both in the north-south and east-west directions. The microseismic events were located at a depth of around 12,600 ft (4000 m); hence, maximum offset-to-depth ratio ranged from 1.5 to approximately 2.5 for the most southerly events. The P-wave arrivals have similar frequency spectra to the P-wave arrivals of Case Study I. The inversion of P-wave arrival times from these microseismic events used a 1D VTI velocity model derived from a check-shot velocity profile and found Thomsen parameters $\delta = 0.06$ and $\varepsilon = 0.16$, indicating relatively strong effective anisotropy, although somewhat smaller than in the Case Study I (where we found $\eta = 0.26$ and $\delta = 0.11$). However, Case Study I used inversion of anisotropic parameters in a homogeneous halfspace, neglecting 1D layered structure of reservoir, which may account for the difference between these two case studies. The important result from this study was the ability to locate all microseismic events shown in Figure 1 with one 1D layered VTI model. The residual traveltimes are relatively small, as illustrated in Figure 4. Furthermore, the residuals from remaining events seem to be consistent which suggests they may result from local heterogeneities (or local statics). The average rms residual for nearly all events is approximately 6 ms across the array. Note that the residuals do not show any systematic bias with offset from the microseismic event indicating that the VTI anisotropy accounted for most of the observed arrival times. This is also obvious from small values of the residuals relative to traveltimes of 1–1.5 s.

Conclusions

We have shown that passive seismic monitoring from surface arrays allows consistent imaging of microseismic events over large areas and long periods of time. The microseismic events observed on surface arrays allow determination of the orientation of the symmetry axis of the anisotropy; VTI anisotropy appears to dominate in the shale reservoirs we have studied. The VTI velocity models have allowed us to map multiple microseismic events over a field-wide area with a single velocity model. Permanent buried arrays offer a unique opportunity to estimate anisotropy owing to the consistency of the receiver response over long periods of time and multiple well treatments. The inverted anisotropic parameters can complement active seismic imaging programs and improve imaging of the target reservoirs. TLE

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