Challenges for microseismic monitoring

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Summary

We review important challenges in microseismic monitoring and interpretation of the microseismic events. We start with locations of microseismic events and the impact of temporal changes in velocity during hydraulic fracturing and consider effects of uncertainty in deviation surveys on both downhole and surface monitoring. We continue with source mechanism inversion affected by low and high frequency signal from microseismic events. Finally, we discuss inversion of corner frequency and its reliability in the presence of complex tube waves. Where available, we suggest potential solutions for these challenges.

Introduction

Unconventional reservoirs require unconventional methods of production to become economical. A key aspect of economic production in these low permeability rocks is hydraulic fracture stimulation, usually in horizontal wells. Microseismic monitoring is rapidly becoming a method of choice for mapping of these fracture properties and characterizing the reservoir away outside of the borehole (e.g., Williams-Stroud et al., 2010). Microseismic events can be mapped either from downhole or surface (or near-surface) monitoring arrays of geophones (or any other seismic receivers). Recently the locations of microseismic events and geometry of the hydraulic fracture mapped from these locations has been complemented with additional parameters of the induced fractures such as source mechanisms and fault plane sizes (e.g., Baig and Urbancic, 2010 or Eisner et al. 2010).

In this study we focus on the challenges in the processing of downhole microseismic monitoring (see Maxwell et al., 2010, for an overview) that the technology needs to overcome before it can provide reliable and robust results for engineering purposes. Where suitable we discuss relevant limitations of the surface monitoring of microseismic events (see Duncan and Eisner, 2010, for an overview) although limitations of the surface monitoring are subject of discussion in a companion paper (Thornton and Eisner, 2011). We hope that this study will stimulate discussion about changes in current practices in monitoring of the microseismic events as the discussion of these limitations has so far been limited to modeling uncertainty in locations (e.g. Eisner at al. 2009).

Locations

The velocity model is a key factor for accurate unbiased locations especially in downhole monitoring with single vertical receiver array (e.g., Jansky et al 2010). Numerous studies show that realistic errors in velocity models (approximately 5% velocity changes or modest dip perturbation) can cause significant bias and mislocations of microseismic events. This is simply a consequence of the fact that the velocity model error is directly projected into either horizontal or vertical position of the microseismic event as arrival times of the direct P- and S-waves can be better explained with erroneous location in an erroneous model. Hence velocity model calibration with sources at known positions became crucial part of microseismic monitoring (e.g., Bardainne and Gaucher, 2010). However, velocity model calibration is frequently repeated for each stage of the hydraulic fracturing (e.g. Pei et al., 2009) resulting in significant (more than 20% is not unusual) changes in the velocity models. These changes are explained by the fact that hydraulic fracturing changes the reservoir rock resulting in strongly altered anisotropic properties between the monitoring array and perforations.

An alternative explanation of stage-to-stage changes in velocity model calibration was offered by Bulant et al. (2007) who pointed out that errors in deviation surveys of both treatment and monitoring boreholes may cause significant and systematic changes in velocity model calibration (resulting in systematic bias in locations of microseismic events, as explained above). They show that VTI parameters of up to 20% (i.e. Thompson parameters ε, $\delta \sim 0.2$) result from an erroneous assumption of a vertical borehole if the deviation survey is not known. Furthermore, they point out that even with measured deviation survey the borehole trajectory is not known accurately and the error increases with length of the borehole. This is particularly an issue with long horizontal wells where cumulative error of only 0.2^{o} results in large errors. This problem is particularly important to downhole monitoring where small errors in source or receiver position project to large errors in velocity model calibration as the relative distance between source and receiver is also small. To our best knowledge this challenging aspect of downhole monitoring is not usually addressed in contemporary practice.

Recently, an increasing number of researchers report on observations of significant changes in anisotropic velocity parameters due to production (time scale of months Teanby et al., 2004) or hydraulic fracturing (time scale of minutes Wuestefeld et al. 2011, Grechka personal communication). If these velocity model changes were indeed confirmed and for example, a hydraulic fracturing would change velocity model by 20% between stages1 and 2, what velocity model we should use for location of events induced during stage 1? Should we use the velocity model stage 1 or of stage 2? Note, that this is not a trivial problem as differences in the located events with model altered by 20% are significant and strongly affect the interpretation of the located events.

Surface monitoring is also sensitive to the velocity model and requires a calibration by location of a source at known position as well. However, the deviation problem is reduced by a factor of two as receivers are known with precision and accuracy exceeding any significant errors in velocity model calibration (GPS positions to centimeters). While position of the source is still subject to errors in deviation surveys, the possible error is much smaller relative to the overall path resulting in much smaller errors in velocity model calibration (estimated less than 5% as discussed in Gei et al, 2011). The velocity model changes due to fracturing will also not affect significantly the locations of microseismic events as the rays between source and receiver travel mostly through overburden and usually travel less than 5% of its traveltime through the stimulated reservoir where velocity model may change. Hence, even 20% change in reservoir rock results only in a 1% change of the traveltime in surface monitoring.

We may conclude from this section, that aside from the deviation survey issues, downhole monitoring with a single vertical borehole needs to overcome significant challenges in obtaining reliable locations. However it seems to be an excellent tool for monitoring of reservoir rock changes.

Mechanisms

Source mechanisms provide additional information on the type of rock failure that occurred as a result hydraulic fracturing, or more generally, stress changes in the reservoir. Source mechanisms can provide information as to whether the failure was mostly shear, (i.e. earthquake like failure along a simple single plane), volumetric (i.e. explosive or implosive failure), CLVD type of failure (i.e. more complex failure with shear along at least two distinctly different fault planes), or combination of the previous. For shear and CVLD types of sources, the source mechanism further provides information on orientation of the fault planes and directions of the tension and pressure axes.

Source mechanisms are usually determined from phase and amplitude information of either direct or (rarely) other waves. Vavrycuk (2007) shows that a single vertical monitoring array of receivers in vertically symmetric media (e.g., VTI layered structure) does not provide sufficient information for inversion of general source mechanism and some additional constraint needs to be added to complement the inversion. If both P- and S-wave amplitudes are used for the inversion, a sufficient additional constraint is the restriction of source mechanisms to being only shear. For example, such a constraint was used by Rutledge and Phillips (2003) to show that a composite source mechanism of similar events can be approximately explained by a shear failure.

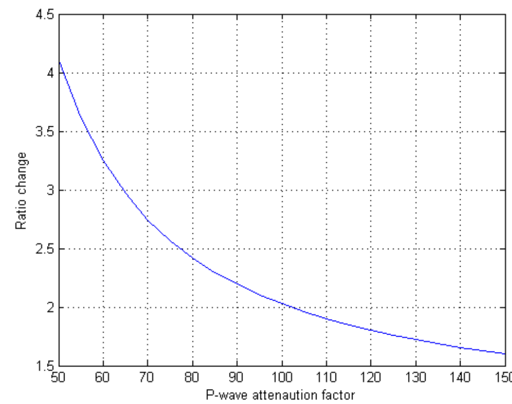

Figure 1 Ratio of ratios of P-to-S-wave relative amplitude in attenuating relative to non-attenuating media (R/R_0 in equation 1). Quality factor of S-waves is one half of the quality factor of P-waves, both P- and S-waves have similar dominant frequency of 100 Hz measured at 300 m distance from a receiver in homogeneous media with α=4000 m/s and β=2000 m.

As discussed, such inversions are based on the direct P- and S-wave phase and amplitude fit to the synthetic data for a particular source mechanism. However, amplitudes become much more sensitive to local velocity variations with increasing frequency content. Hence, inverting for source mechanisms, using higher frequency signals is a drawback rather than an advantage. Perhaps the biggest drawback to using high frequency information for source mechanism inversion is the effect of the usually unknown P- and S-wave attenuation along the path between source and receivers. As attenuation increases exponentially with the frequency of the signal, we should be using as low frequencies as possible when inverting for source mechanisms. The previous statements assume the attenuation models of P- and S-waves are poorly known, which is usually the case. To illustrate the sensitivity to attenuation, we consider a simple homogeneous medium with P- and S-wave velocities α and β respectively, a microseismic event at distance d, and direct P- and S-waves with dominant frequencies of f_P and f_S. The amplitude ratio R of the P- to S-waves is

$$R = R_0 e^{-\pi d\left(\frac{f_P}{\alpha Q_P} - \frac{f_S}{\beta Q_S}\right)}, \quad (1)$$

where R_0 is the ratio of P- to S-wave amplitudes in a perfectly elastic media (neglecting attenuation) and Q_P and Q_S are quality factors of the P- and S-waves, respectively. Figure 1 shows the ratio of R to R_0 for α=4000 m/s, β=2000 m/s, f_P=f_S=100 Hz, and Q_P/Q_S = 0.5. We can see that neglecting attenuation may lead to significant changes in amplitudes and especially the estimated ratios of P- and S-waves resulting in incorrectly inverted source mechanisms. In fact, the more attenuated S-waves result in relatively high P-wave amplitudes which can be misinterpreted as signature of tensile opening.

Surface monitoring usually relies on the inversion of relative P-wave phases and amplitudes over multiple azimuths and offsets. Naturally such inversion is not sensitive to S-wave attenuation quality factor and is reduced to sensitivity of P-wave quality factor. Naturally, surface inversion uses low frequency signal as high frequencies are attenuated. A similar strategy would be highly beneficial for downhole source mechanisms inversion when possible.

High frequency challenge

Finally, the last group of advanced parameters extracted from microseismic monitoring to be discussed, originate from the high frequency part of the seismic wave spectrum. Probably the most useful parameter is the corner frequency which is related to source dimensions (see Lay and Wallace 1995 for more details). The corner frequency is the frequency corresponding to the peak of the amplitude spectra in a perfectly elastic medium of direct P- or S-waves. The source dimension determines the peak frequency by rupture velocity along the dimension of the source (radial or square). The source dimension is then used to determine stress drops associated with microseismic events that may be further used for reservoir characterization. However, determination of the corner frequencies is a non-trivial matter, particularly in the downhole monitoring environment. The attenuation of higher frequencies may cause artificial shift of the peak in the amplitude spectra to lower frequencies, although this may be resolved by careful analysis (flattening) of the displacement spectra. Perhaps the most difficult challenge in determination of any high frequency parameters is the coupling of seismic waves to borehole waves in the monitoring well. For example, Dong and Toksoz (1995) show that seismic waves with energy at 200-300 Hz couples well to tube waves in vertical boreholes creating additional complexity in the observed wavefield. While tube waves are certainly an interesting phenomena, they are related to parameters of the monitoring borehole, not the microseismic source. Hence, corner frequencies above 200 Hz are unlikely to be recovered from downhole monitoring unless some kind of methodology can be established to decouple tube waves and direct waves.

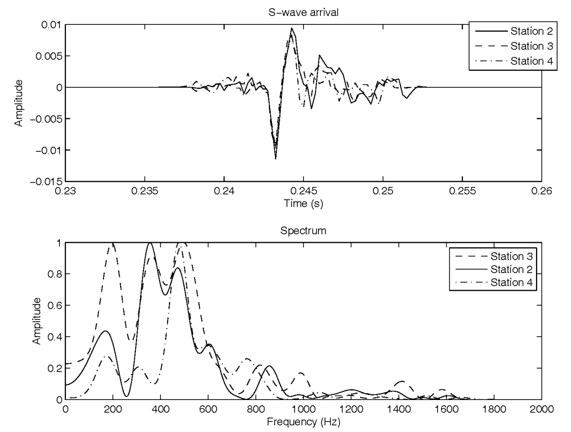

Figure 2 Particle velocity and their spectra for S-wave arrival on three geophones (station 2-4) with a sample rate of 0.250 ms in a nearly vertical borehole. The event is approximately 400 ft (121 m) away from the Station 2. The spectra were taken in a symmetrical window with a total length of 10.0 ms around the S-wave arrival with an additional 5.0 ms taper on either edges. Stations were separated by 50 ft (15 m).

This problem is illustrated in Figure 2 where we display a typical seismogram of an S-wave observed in a monitoring borehole. The spectra of the arriving S-wave show significant differences from station to station. Considering the fact that stations are separated by a short distance (50 ft) from each other, it is unlikely that the differences observed in Figure 2 are due to source radiation or path effects. In fact, the shifts in the observed peaks of the spectra can probably be attributed to interference of tube waves and body waves. If the spectra were not affected by tube waves, one would expect the amplitude spectrum to peak at the same frequency for all three receivers with a simple bell-shaped peak. However, such spectra are almost never observed in borehole monitoring despite the proximity to the source. As the spectra peak above 200 Hz, one needs to consider possibility that these peaks correspond to the complex interference of tube waves and direct waves from source.

Surface or near-surface monitoring does not suffer from a tube wave problem because the purpose drilled boreholes for near surface monitoring are usually cemented and back filled to surface. However, surface monitoring does not allow determination of corner frequencies, as the high frequency signal is usually entirely attenuated.

Discussion/Conclusions

This study is not aimed at discouraging the use microseismic downhole monitoring; rather it is aimed at pointing out some of the challenges especially related to some of the more advanced interpretation. We believe these challenges will be eventually met. For example, initial processing to lower frequency signal may reduce demands on both velocity model as well as stabilize inversion of source mechanisms as pointed out in this study and also suggested by Leaney and Chapman (2010). This is analogous situation to waveform inversion in active seismic imaging where initial iteration on low frequency data is necessary for successful inversion. High frequency signal can be then added later on to provide additional information if a model is sufficiently accurate.

One of the unresolved issues that needs to be addressed is uncertainty in receiver and calibration shot position. Microseismic event location probably requires the use a time of dependent velocity models if the receivers are close to a rapidly changing reservoir rock formation. Finally, one should not try to provide high frequency parameters of microseismic events unless the effects of tube waves and attenuation can be removed perhaps by cementing or draining monitoring boreholes.

Acknowledgements

Authors are grateful for Microseismic, Inc. for support and useful discussion, particularly to Peter Duncan and Mike Mueller whose contributions greatly improved this study.

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