Future of Microseismic Analysis: Integration of Monitoring and Reservoir Simulation

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Introduction

Monitoring of microseismic events induced by reservoir stimulation has become a key aspect in evaluation of hydraulic fractures and their optimization. Future developments of this technology are dependent on improvements in multiple discipline areas, two of which are discussed in this study: better quantification of event locations along with the velocity model, and improved understanding and calibration of the type of rock failure responsible for the seismic events.

Currently, locations of microseismic events are used to infer the geometries of hydraulic fractures. These locations are inverted from seismic signals recorded by sensors either distributed at the surface or in dedicated monitoring borehole(s). The accuracy and precision of the inverted locations depends on both the signal-to-noise ratios of seismic data and the spatial distribution of the receivers. While surface monitoring usually suffers from low signal-to-noise ratio, the ability to place receivers in multiple azimuths and offsets allows for precise event location. The major challenge of the surface monitoring remains distinguishing noise from the signal. On the other hand, downhole monitoring provides robust detection due to a higher signal-to-noise ratio (if an event is sufficiently close to the monitoring borehole); however, precise location of events might be difficult, especially in the case of a single monitoring well. Thus, integration of downhole and surface monitoring may be beneficial to both methodologies.

Observed seismic waves carry information about the reservoir properties and the mechanisms of microseismic sources, so that in addition to using microseismic events to infer hydraulic fracture geometry, analysis of the source mechanism allows determination of the type of rock failure that occurred during the stimulation. Fracture stimulation models are often based on generating tensile fractures parallel to the maximum stress direction in the reservoir but analyses of the observed microseismic events are dominated by shear failure mechanisms. An assessment of whether the shear failure represents creation of new fractures or reactivation of the existing ones is often based on conceptual models with little data for validation. Analysis of data obtained from a microseismic monitoring project where an image log was acquired in the treatment well allows one to validate the model interpreted from the event locations and the inverted source mechanisms. Integration of source-mechanism analysis with information obtained from image logs leads to a better constrained reservoir model populated with fractures away from the wellbore.

In this paper, we discuss how different monitoring methods allow microseismic technology to infer the properties of shale-gas reservoirs and the effects of hydraulic stimulations. Two studies are presented: a modeling illustrating the value of combining different microseismic acquisition geometries, and an example from a microseismic monitoring project where the rock-failure mode estimated from source mechanisms is validated with image logs.

Theoretical models: Joint event location and velocity inversion

The first example of integration shows that joint event location from surface and downhole receivers improves the precision of locations and allows estimation of anisotropic velocity models. While synchronization of timing between downhole and surface monitoring is essential for identification of corresponding events (Eisner et al., 2010), it is even more crucial for joint imaging where the accuracy of synchronization needs to be a fraction of millisecond.

Usually, only the P-wave velocity model is constrained by active seismic, while the S-wave models are constructed from dipole sonic logs. Because dipole sonic data are measured at frequencies 2-20 kHz and along a borehole, they are notoriously difficult to combine with the P-wave velocity models constructed from active seismic data. Furthermore, shale formations are well known for their elastic anisotropy, which is difficult to infer from borehole measurements. Thus, initial velocity models constructed for surface and downhole microseismic measurements have to be calibrated with a source at known location, such as a perforation shot.

Joint event location and velocity-model inversion of surface and downhole observations potentially offers more accurate locations along with an improved velocity model. Here we investigate a synthetic data set under the assumption that both surface and downhole monitoring is done with three-component receivers. We assume that our data have sufficient signal-to-noise ratio to measure direct arrivals of both the P- and SV-waves. This assumption is rather optimistic as surface data are usually acquired with vertical receiver components only because the S-wave signal-to-noise ratios are often smaller than those for the P-waves (e.g. Kolinsky et al., 2009). In some cases, however, such data might be acquired, and we show that integration of downhole and surface data sets is beneficial for the inversion of effective anisotropic velocity models and for precise event locations.

We generate synthetic arrival times of the P- and SV-waves from a microseismic event to 11 receivers in a vertical monitoring borehole and to a 2D grid of 121 receivers at the earth's surface (Figure 1). The monitoring geometry is similar to that investigated by Eisner et al. (2009) who examined the accuracy of event locations inverted either from surface or downhole observations. Our study assumes several additional degrees of freedom: the velocity models are inverted simultaneously with the locations, these velocity models are transversely isotropic with the vertical axis of symmetry (VTI), and they are different for the surface and downhole data because ray trajectories from the event propagate through different volumes in the subsurface (Figure 1) and observed waveforms are usually have different frequencies. Thus, for a single microseismic event, we invert noise-contaminated traveltimes for 12 quantities: x-, y-, z-

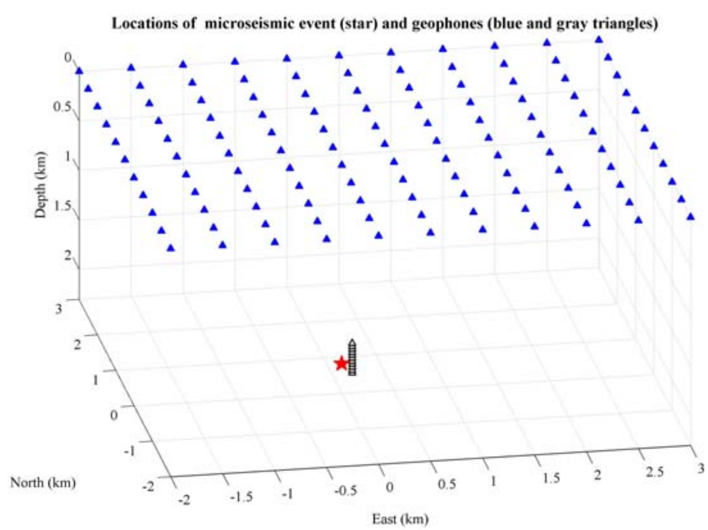

Figure 1. Microseismic event [red star at (0, 0, 2) km], downhole and surface receivers (gray and blue triangles, respectively).

coordinates of the event location, the origin time, and four parameters (the vertical compressional and shear velocities and Thomsen coefficients δ and ε) of each of the VTI models. Figure 2 shows the results of the inversion of different data sets. Clearly, by combining the surface and downhole observations, we not only locate the event most precisely but also properly constrain the velocity models. The ability to jointly estimate the velocities for the downhole and surface data provides an important improvement to conventional monitoring because either data set cannot uniquely resolve the event location and the velocity (e.g., Grechka, 2010). Analysis of Figure 2 reveals that the downhole and surface data complement each other, helping to remove the trade-off between the event coordinates, the origin time, and the velocities.

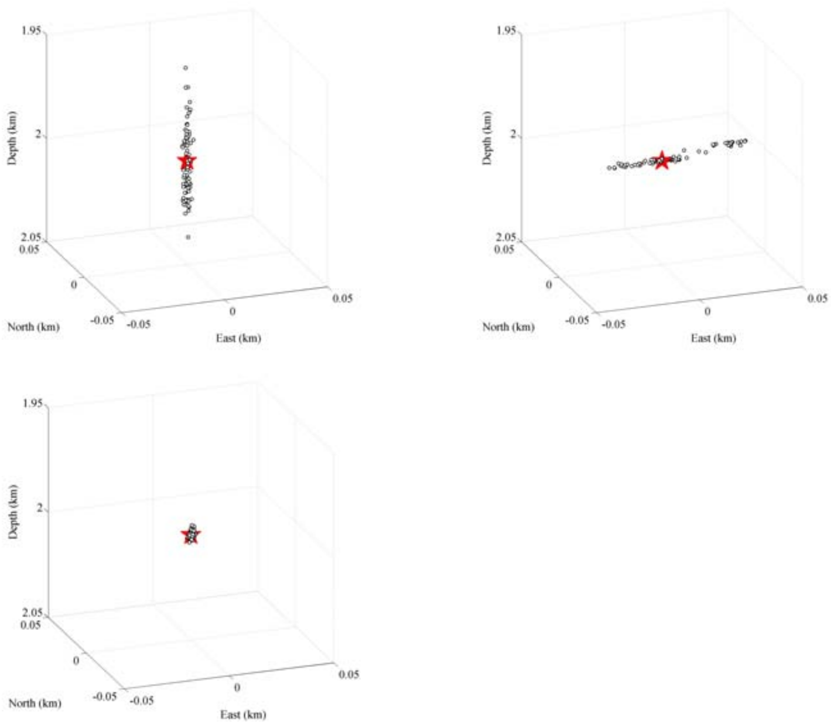

Figure 2. *Results of inversion of noise-contaminated traveltimes for the source location (circles) simultaneously with VTI velocity models (not shown) from surface data only (left), downhole data only (middle), and jointly (right). The red star indicates the correct event location.*

Case Study: Source mechanisms of microseismic events and stimulated fractured reservoir characteristics

Upscaling measured data from wellbores is a formidable challenge in characterization of reservoir properties and significant assumptions need to be made regarding the manner in which the data character changes away from the wellbore. Results of analysis of borehole images (e.g., FMI or acoustic image logs) for the presence and orientations of natural fractures are usually extrapolated to a larger scale in order to specify the reservoir properties between the boreholes (Wu and Pollard, 2002; Prioul and Jocker, 2009). As fractures are characterized by appreciable spatial variability, the key question is the feasibility of extrapolating the measurements of fractures from wellbores made on the centimeter scale to the reservoir, where fractures can exist on the scale of hundreds of meters.

Rutledge and Phillips (2003) proposed that natural fractures control the orientations of failure planes of induced microseismic events. In their model, small-scale natural fractures coalesce to form larger faults of several meters forming fault planes of microseismic events. They observed strike-slip source mechanisms on vertical failure planes for induced microseismic events striking nearly parallel to the natural fractures in Cotton Valley rocks (Dutton et al., 1991). However, because observations of Rutledge and Phillips (2003) were based on inversion from a small number of geophones in two monitoring boreholes, only a composite (average) focal mechanism from many events grouped under the assumption of the mechanism similarity could be inverted.

In our study, surface microseismic monitoring was done to assess the effectiveness of two different fluids used for fracture stimulations in a horizontal well with a 3,500 ft lateral section drilled in the Arkoma Basin in Oklahoma. The array consisted of 1078 stations of 12 geophones laid out in a radial pattern around the treatment well. Microseismic events induced by the hydraulic fracturing were located by a beamforming process, which is essentially a one-way depth migration. The observed distribution of microseismic events created by the stimulation treatments suggested a number of planar fractures emanating from the horizontal wellbore and forming trends at an angle of about 50 degrees from the direction of the lateral (Figure 3). The azimuths of the produced microseismic trends correlate with those of natural fractures interpreted from the FMI logging done in the well prior to the treatment.

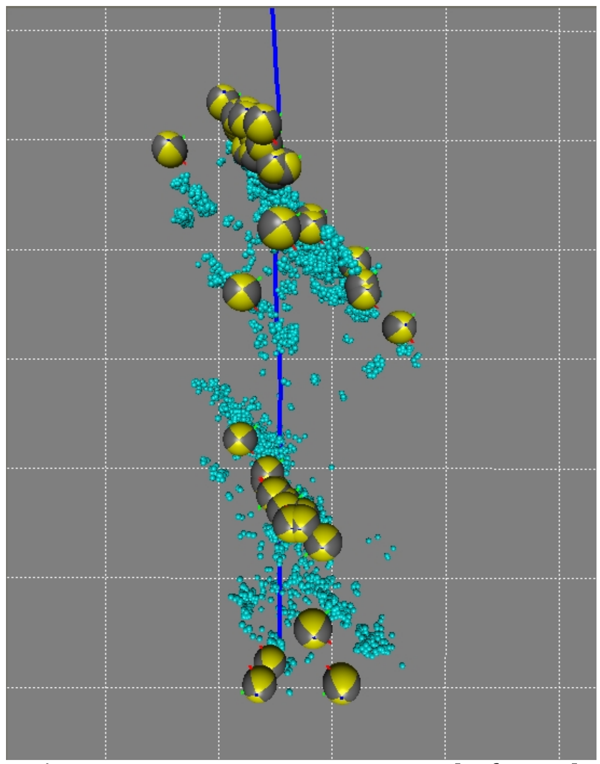

Figure 3. *Microseismicity trends formed during hydraulic stimulation (cyan dots). Source mechanisms are plotted as beach ball representations at locations of large microseismic events.*

Source mechanisms of detected microseismic events are plotted as beach balls at their respective event locations in Figure 3. The inverted mechanisms of representative events are very close to pure strike-slip because 90% of the inverted moment is due to pure shear motion along nearly vertical fault planes. The seismic moment of the largest event is approximately $3.4 \cdot 10^7$ Nm, corresponding to the moment magnitude of -1.1.

Natural fracture orientations identified on an image log acquired in the treatment well are oriented at $84^o/46^o$ dip/dip azimuth. The source-mechanism solution yields nearly identical orientations of natural fractures to those measured in the wellbore. Figure 4 shows the strike rose plots (left column) and pole plots (right column) of the orientations of natural fractures observed in the image log (top row) and estimated from the source mechanisms (bottom row). The two sets are almost identical, except for about 10^o difference in the dip direction of the nearly vertical planes for the source-mechanism solutions. This suggests that the existing natural fractures were reactivated during the treatment. A significant non-shear component of the inverted mechanisms is also present, indicating that tensile fracturing mechanisms are active; hence, fracturing fluids and proppants could invade the fault planes. Fractures interpreted in the image log include open and partially closed natural fractures as well as the drilling-induced fractures with orientations that could be influenced by the existence of natural fractures. The source mechanisms suggest strike-slip reactivation of the natural fractures only. Drilling-induced fractures that strike at 88^{o} azimuth are also interpreted from the image log. The E-W maximum horizontal stress direction indicated from the drilling induced fractures is consistent with the pressure and tension axes obtained from the source-mechanism inversion solutions, so that the same conclusion can be derived via either method.

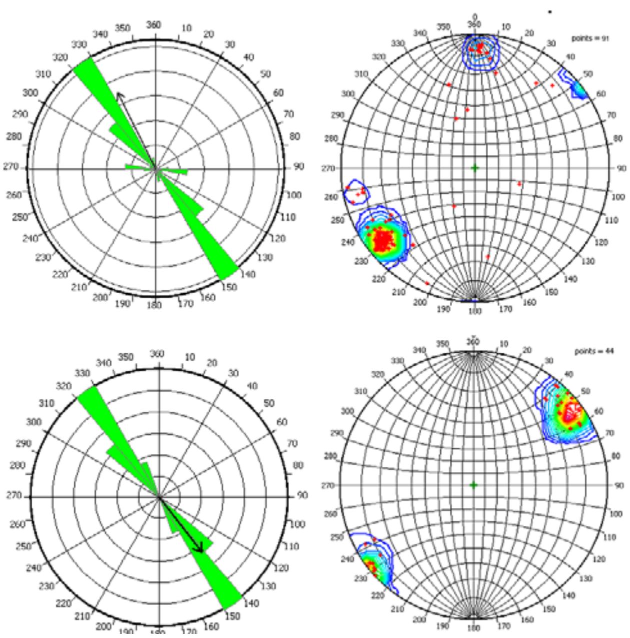

Figure 4. *Orientations of natural fractures interpreted from an image log (top row) and estimated from the source mechanisms (bottom row).*

Validation of the source mechanisms with the image-log analysis implies the availability of data to characterize fractures away from the wellbore and, thus, fill the gap between the centimeter and the hundreds of meter scales. The event trends provide a calibration for the maximum probable fracture length, with each mechanism representing the location of a slipped patch; the source-mechanism moment can be further calibrated to directly relate the event energy to the size of individual fractures.

Conclusions

Two approaches to integration described in this paper might significantly increase the value of microseismic technology. The integration of monitoring methods is shown to reduce the event-location errors related to different acquisition configurations. The use of joint downhole and surface acquisition geometries also provides important information about the nature of rocks and enables constructing more accurate velocity models. Methods that integrate data at different scales allow validation of observations that otherwise would be highly uncertain. Improved understanding of rock behavior during hydraulic stimulation provides the information necessary to better design the treatments as well as to create more constrained geological models for reservoir simulation.

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