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Investigation of Increased Microseismic Deformation Along a Hydraulic Fracture Treatment Well

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Summary

A hydraulic fracture case study in the Upper Montney is examined, where the largest microseismic events (M_W > -1.5) were found to cluster along the treatment well, while away from the well the events were typically smaller (M_W < -2). An integrated microseismic-geomechanics investigation was performed to examine the differences.   Source mechanisms were analyzed from the microseismic data to examine potential differences between these subsets of events. Theoretical seismic amplitude ratios are forward modeled to match observed amplitudes from the microseismic data. The data indicates two distinct fracture sets exist; one for each event set. These fracture orientations can then be used as a guide for construction of a discrete fracture network (DFN) for input into a 3D geomechanical model.

Geomechanical modeling was also performed to investigate conditions which could result in the generation of increased microseismic deformation near the treatment well. Since this was an open-hole completion, one plausible scenario was initiating a pre-existing fracture that crosses the treatment well. Injecting into a favorably oriented joint results in the release of more seismic energy consistent with the field observations.

Introduction

Microseismicity is a widely used qualitative tool for estimating the extent and complexity of the stimulated fracture network (e.g., Maxwell, 2014). In addition to analyzing the spatial distribution of the microseismic cloud, microseismic source-mechanism studies have demonstrated that the mode of failure is predominately shear in nature suggesting that microseismicity is a result of slip along prexisitng fractures. In general, fracture logs and/or outcrop data indicates a finite number of fracture sets, often a result of present and past stress orientations. Microseismic data often shows strong azimuthal variations of the P/Sh, P/Sv and Sv/Sh ratios (Rutledge et al., 2013). After careful examination of the amplitude ratios of the microseismic data it is possible to subdivide the microseismic cloud into event sets with consistent failure mechanisms of parallel joint sets. For example, events can be sorted based on spatial-temporal characteristics or based upon source characteristics such as magnitude.

In this paper, microseismic data is examined to identify differences in failure mechanism and deduce the fracture sets of the DFN. Here we integrate geomechanical modeling to investigate differences in microseismic magnitudes observed around a treatment well to replicate observed source mechanisms. Integrating the microseismic with the geomechanics not only helps understand the fracture growth and causes of the observed differences in the microseismic deformation, but more importantly can then also be used to quantify the complete fracture network including the effective propped portion (e.g. Chorney et al., 2016).

Method

Microseismic data was acquired in the Upper Montney formation during a sliding-sleeve, open hole completion with an 18 level horizontal monitoring array with 30 meter sensor spacing. The first step of analysis was to examine trends including detection biases related to acquisition geometry. By filtering events by moment magnitude >-1.5, a localization of the events near the sleeve ports along the wellbore is highlighted (Figure 1a). By filtering for smaller magnitude events (Mw<-2.0), the opposite trend is noted and a more complete image of the fracture geometry can be seen (Figure 1b).

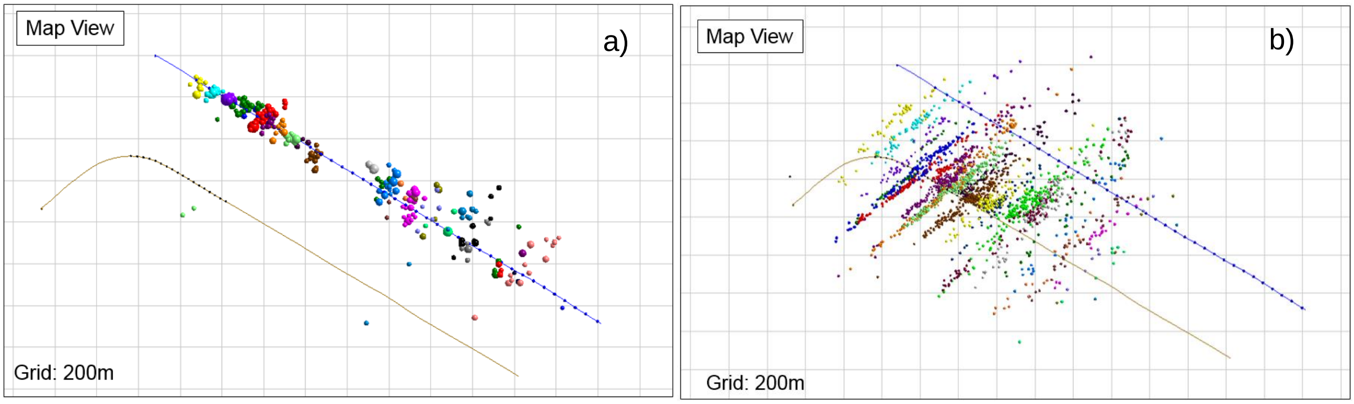

Figure 1: Comparison of spatial distribution of events when grouped by magnitude. **a**) Events Mw -1.5 and larger, **b**) events Mw -2.0 and smaller. Event size scaled by moment magnitude, colored by stage.

Once data was sorted into two magnitude ranges (Mw>-1.5, Mw<-2.0), seismic amplitude ratios for P/Sh, P/Sv, and Sh/Sv were examined from individual sensors to determine the fracture planes common to the events (Rutledge et al., 2013). To improve the determination of amplitude ratios, only high quality events were analyzed by using a calculated Confidence Factor greater than 2.5.

Microseismic geomechanical modeling scenarios were then tested (following Chorney et al., 2016) specifically to reproduce the near wellbore, high magnitude events (Mw>-1.5) and determine possible causes. The injection was simulated with the same treatment parameters as in the actual treatment.

Results

After decomposition of events into the two event sets, the difference in geometry is readily apparent (figure 1). Further analysis of the seismic amplitude ratios reveals two unique fracture orientations. The near wellbore, high magnitude event set (Mw>-1.5) matched most closely a source with a fracture azimuth of 40 degrees and a dip of 35 degrees. The lower magnitude event set (Mw<-2.0) was more appropriately matched to a source with a fracture azimuth of 87 degrees and a dip of 35 degrees. A spatial comparison of the observed and theoretical P/Sh ratios for the events in the high magnitude dataset is shown in figure 2. Another quality control plot is shown in Figure 3, which shows the theoretical contours for the best fit mechanism plotted along with the values obtained from the data. A similar method was used to determine the orientation of the fracture azimuth common to the low magnitude events.

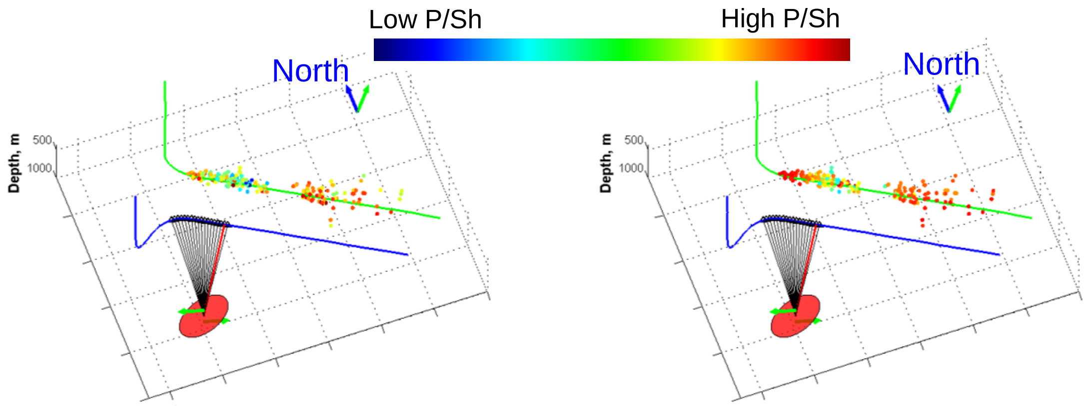

Figure 2: Computed P/Sh amplitude ratios (left) and theoretical ratios (right) for the high magnitude event set. Event are colors by P/Sh ratio, and the computed mechanism is illustrated by the red plane. Grid spacing is 1000 meters.

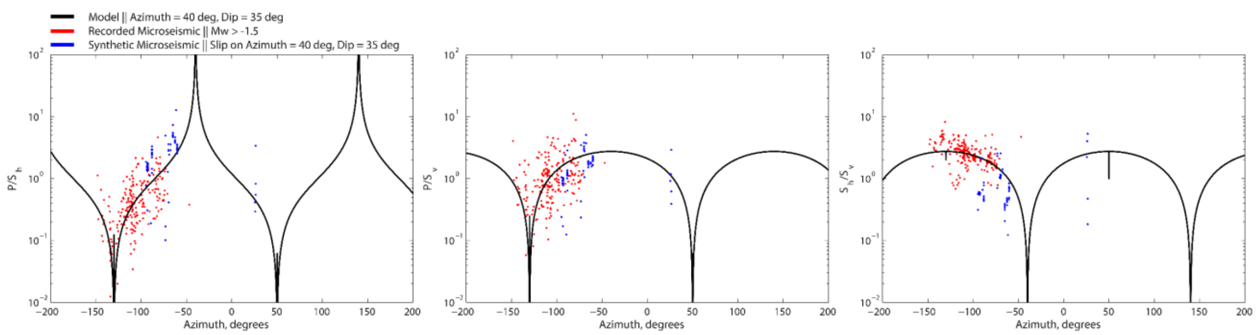

Figure 3: Observed amplitude ratios plotted against theoretical values for a double-couple source with an azimuth of 40 degrees and a dip of 35 degrees. Black lines represent theoretical radiation pattern for best fit fault plane, red dots are reported values from the events. Blue dots are values from the synthetic microseismic generated from the geomechanical modeling result. Azimuth is measured relative to grid north, and represents the direction from source to sensor.

Various modeling scenarios were performed to match the microseismic observations and calibrate the geomechanical model, including the observation of high magnitude events near the wellbore. One plausible scenario that would recreate the observance of these larger magnitude events is to have a fracture near the injection point oriented 45 degrees from the maximum principal stress direction (figure 4). In this case, shear stress along the joint is most efficiently released and a larger seismic moment will result. The treatment well was an open-hole completion, where the fracture initiation is generally thought to occur through pre-existing fractures crossing the treatment well.

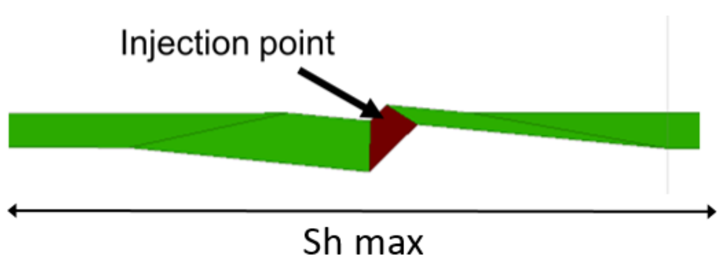

Figure 4: Geomechanics fracture geometry with an oriented pre-existing fracture (red) that turns into a primary tensile fracture (green) away from the injection point.

Figure 5 illustrates the distribution of seismic moment relative to the injection point. There is a large increase in moment associated with slip along the fracture early in the injection.

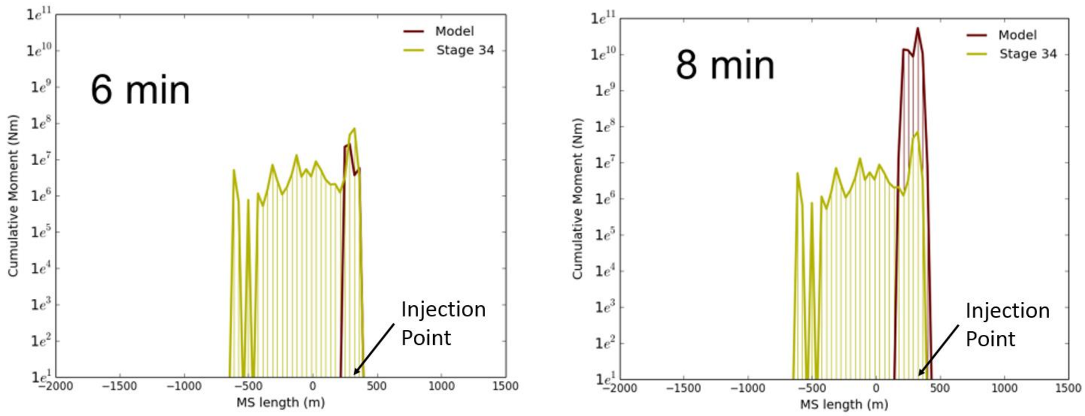

Figure 5: Distribution of cumulative moment for an example stage (stage 34, in yellow) and the modeled result (dark red) during the start of injection. Modeled result shows the moment distribution after 6 minutes of injection (left), and again after 8 minutes of injection (right). Note the large increase moment near the injection point, reflected by the model.

Conclusions

Microseismicity recorded during hydraulic fracture treatments provides an image of the spatial and temporal characteristics of the hydraulic fracture network. Source mechanisms can also be investigated to infer orientations of distinct fracture sets within the reservoir. In this case study, event grouping by magnitude range reveals a distribution of slightly larger magnitude events near the treatment well and smaller magnitude events associated with the propagation of the hydraulic fracture. Here we used a microseismic geomechanical model to investigate the increased microseismic deformation near the well by initiating a hydraulic fracture through a pre-existing fracture crossing the well. The modeling confirms larger moment release with this scenario which is consistent with expected fracture networks for this open-hole completion. The study illustrates the importance of designing the microseismic monitoring array for maximum coverage of the injection sequence in order to fully interpret the fracture geometry, and to populate event sets for accurate microseismic DFN construction. Although microseismicity only represents a small fraction of the total deformation, it provides constraint on the fracture geometry and valuable insight for construction of discrete fracture networks which can be populated within 3D geomechanical models, providing a more complete and quantitative understanding of the deformation and evolution of the reservoir.

References

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