

Integrated analysis for fracture identification during hydraulic fracturing

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Summary

In order to improve our understanding of the interaction of the hydraulic fracture with pre-existing structures in reservoirs, we focused on separating microseismicity related to the hydraulic fracture propagation and microseismicity occurring along the pre-existing structures. We analyzed microseismic activity detected during the stimulation job in a horizontal well with ten stages. The microseismicity aligns in two major trends, E-W and NE-SW. The microseismicity in the NE-SW trend is aligned with the maximum horizontal stress and is related to the hydraulic fracture propagation. The E-W trend is related to the interaction of the hydraulic fracture with the pre-existing structures in the area. Some stimulated stages show very clear and distinguished spatial separation of microseismicity related to the two trends while some stages have more complex pattern. We combine several techniques that help to distinguish various types of seismicity: data set separation, geomechanical, magnitude-frequency, and well pressure analyses. The synthesis of the various methods helps to improve our understanding of the well stimulation. Overall, we almost doubled the number of hydrofractures and fault/fracture zones in comparison to the original interpretation based only on the microseismic mapping and we better constrained the half-lengths of the hydraulic fractures. The detailed data analysis strongly suggests that some hydraulic fractures may be aseismic.

Introduction

We analyze microseismic activity detected during the stimulation job in a horizontal well containing ten stages. The microseismicity aligns in two major trends, E-W and NE-SW (Figure 1). Only some stages show clear development of the hydraulic fracture when other stages are at least partially aseismic (in a sense “not detected by a surface array”). In some stages, microseismic activity increases towards the end of pumping and continues strongly afterwards. The questions related to this data set are summarized as:

- The two main microseismic trends seem to be related to two different processes: the hydrofracture propagation and the reactivation of the pre-existing fractures. Can we separate microseismicity related to the two processes? The hydraulic fracture will most likely propagate in the different direction than is the orientation of pre-existing faults/fractures. Does the separation help to determine the length of the hydraulic fracture?
- Are the aseismic areas an aseismic hydraulic fracture or an unstimulated area?
- Why each stage has different microseismic activity? Is it due to the local conditions?
- Why is microseismicity recorded mainly towards the end and after the end of pumping?

Theory and/or Method

The micro-seismic event dataset was derived from the processing of a 3D patch based surface seismic data set. The recording was made passively during and between the HF stimulation operations.

Through 10 stages of the stimulation, more than 4000 micro-seismic events were detectable and locatable. These events occurred during and after the active pumping stages.

Data Separation

In order to estimate the hydraulic fracture length, it is important to isolate microseismicity that is relevant to the hydraulic fracture propagation. As a first step of the analysis, the events that occurred during the injection are separated from the events that occurred past the injection. After the injection stops, the pressure gradient changes and the fracture cannot propagate in the tension any more. The main hydraulic fracture closes changing thus the stress regime in its surrounding. By separating the data according to the injection time, we separate the events that are not related to the hydraulic fracture propagation and therefore related to the fault/fracture reactivation.

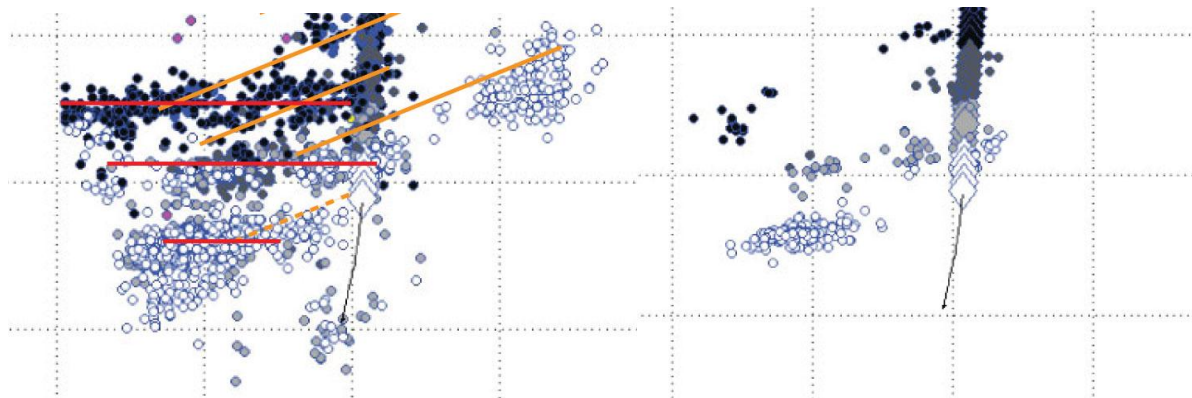


Figure 1: All microseismic activity (left) and microseismic activity that occurred during the injection (right). The display is the same as on Figure 1.

Geomechanics

Hydraulic fracture propagates in the plane perpendicular to the minimum stress in the region. The extent of the fracture is limited by the stress barriers that are typically present in the vertical direction due to the stratigraphic layers but also in a horizontal direction related to the local pre-existing structures and heterogeneities. The microseismic events related to the hydraulic fracture propagation should align along the plane of the hydraulic fracture. Because of the stratigraphic layers, microseismicity often aligns along the maximum horizontal stress direction (S_{Hmax}). From the set of the pre-existing structures of various orientations, the set most favorably oriented for the reactivation is with an azimuth about ~ 30 degrees from S_{max} (pole to the fracture lies in the plane of S_{max} and S_{min} and is inclined 30 degrees from S_{min}). Therefore, microseismicity related to hydraulic fracture propagation and reactivation of pre-existing structures should show different geographical trends.

Engineering curves

Pressure decline in the well and injection rate provide additional constrains to the data separation. If pressure in a well suddenly drops while injection rate is hold constant, some significant volume of fluids got lost in the formation. The sudden drop could be most likely related to the loss of fluids on a fault.

Magnitudes, range of magnitudes, and b-values

Magnitudes of events and b-values provide an additional constrain to the data separation. Such a technique has been used for interpretation of microseismicity related to the hydraulic fracturing (e.g., Urbancic et al., 1999, Maxwell et al., 2002, Schumila et al., 2009, Baig et al., 2010, Vermylen and Zoback, 2011). The b-value is related to the relative magnitude distribution in a data set: If the logarithm of the number of earthquakes of a given magnitude is decreasing by 1 with the increasing unit of magnitude, then b-value is 1; the logarithm is decreasing by 2 with the increasing unit of magnitude,

then b-value is 2. From the interpretation point of view, b-value close to 1 is typical for tectonic earthquakes (Felzer et al., 2004) and b-value >1 is typical for earthquake swarms and hydraulic fracturing (Schumila et al., 1999, Baig et al., 2010). For the value of the magnitude itself, bigger magnitudes are usually signs of shear events on larger pre-existing structures.

Examples

This data set shows two trends of microseismic activity, E-W and NE-SW. After separating the events according to the injection criterion, microseismicity in these two trends separates: The NE-SW trend is characteristic of microseismicity during the injection time and the E-W trend is characteristic of microseismicity that occurred mostly after the injection has stopped. The events that occurred during the injection show clear alignment along the maximum horizontal stress in the region; this confirms that they are related to the hydraulic fracture propagation. The seismicity that occurs after the injection has distinct E-W trend that is related to the reactivation of a pre-existing structure (Figure 1). In this case, the well was drilled to intersect the maximum possible number of natural fractures so its direction is not aligned with the S_{hmin} .

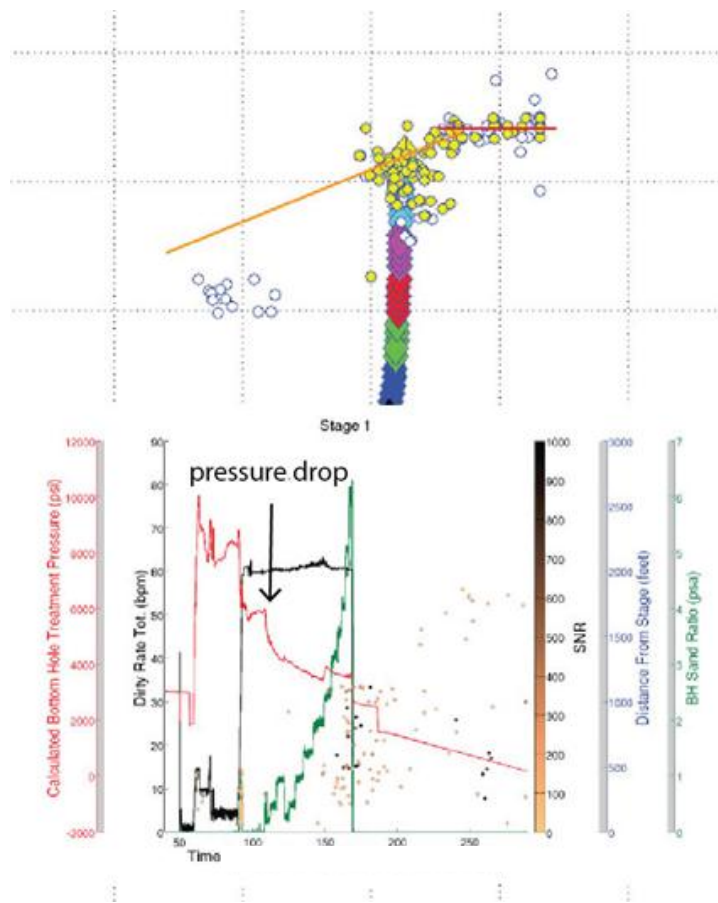


Figure 2: *Top*: Another example of microseismicity occurring during (yellow) and after (white) the injection. The interpreted hydraulic fractures are shown by orange and pre-existing structures by red lines. *Bottom*: The injection rate (black) and pressure (red) during the stage stimulation. Microseismicity is shown by circles colored according to the SNR (signal to noise ratio).

Microseismicity that occurred during the injection time is significantly less numerous. In order to understand the stimulation and to determine the hydraulic fracture length and the stimulated reservoir volume, it is not necessary to have a lot of microseismicity but to understand to which process

microseismicity relates to. By selecting only the injection events, it is possible to see the events aligned in the direction of the maximum horizontal stress and therefore to interpret a hydraulic fracture for each stage, which was not possible while interpreting all microseismicity at once. In this case we increased the interpretation from one to three hydraulic fractures.

A similar example is shown on Figure 2. During this stage, microseismic activity changes the trend from NE-SW to E-W on the eastern side of the well during the injection period. By comparing with the engineering curves, a significant pressure drop of ~ 3000 psi occurred during the simulation that coincides with the change in the microseismic trend and suggests that a pre-existing fault was intersected by a hydraulic fracture during injection time on the E side of the well.

The west wing of the hydraulic fracture has no seismicity during the injection time. The seismicity only occurs after the injection has stopped and it is located far from the injection point. Such an occurrence strongly suggests that there is an aseismic hydraulic fracture (in a sense with significantly smaller magnitudes than other events) that intersects a pre-existing structure at the distance and only the post-injection seismicity is detected. This result suggests that hydraulic fractures may be aseismic (in a sense not detected by the surface network) and that a detailed analysis of microseismicity is needed to understand the stimulation.

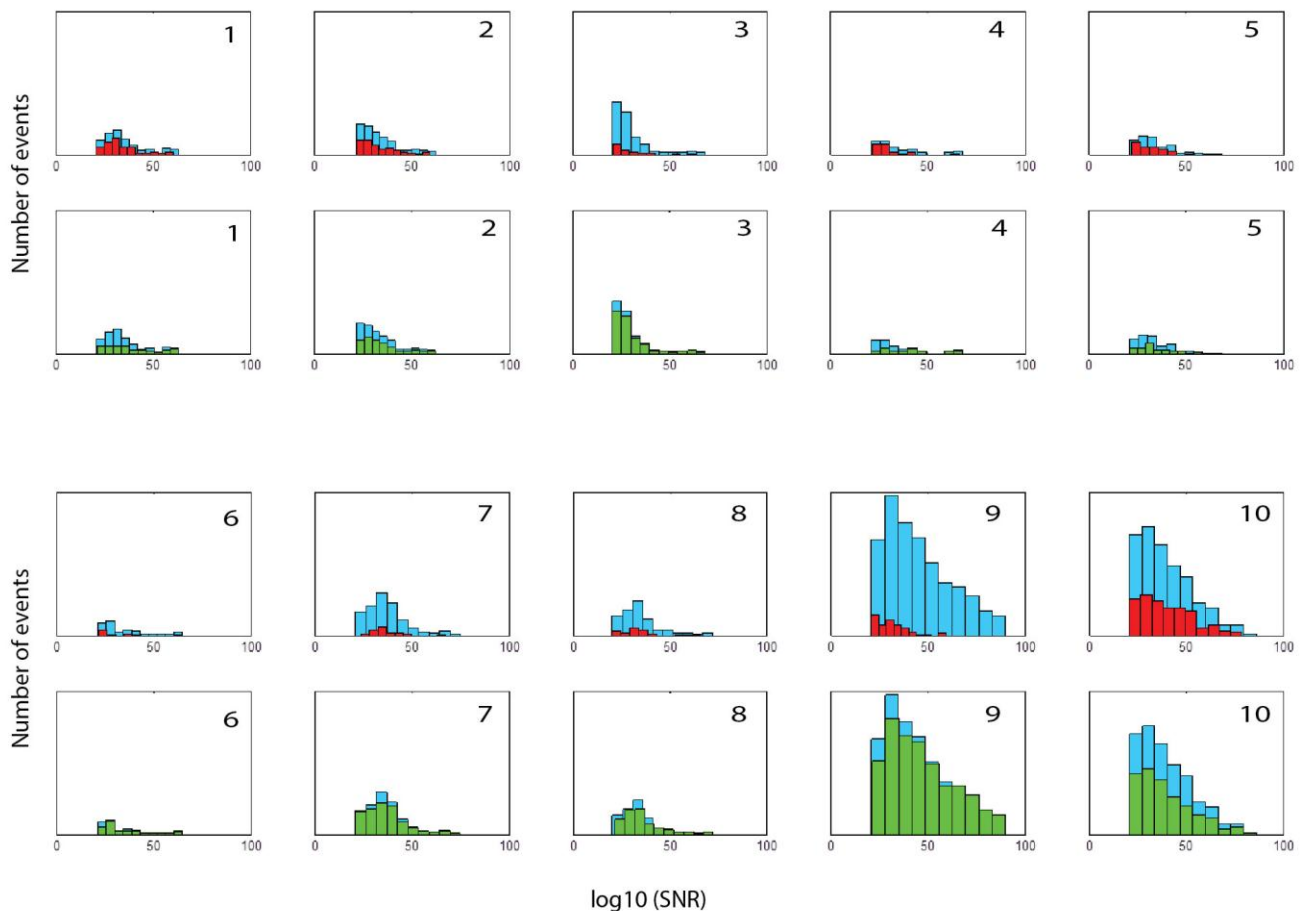


Figure 3: Histogram of events for given SNR for the individual stages (numbered 1-10). The blue bars represent the SNR distribution of all microseismic events. The red and green bars represent the SNR distribution of microseismic events during and after the injection, respectively.

Another interesting characteristic to look at is the SNR (magnitude) distribution of microseismic events that occurs during and after the injection. Figure 3 shows histograms of these distributions stage by stage, and we separate the during-injection events from the after-injection events. What we observe is

that the SNR range of during-injection events is smaller than the one of post-injection events. For injection events, the SNRs are mainly distributed around values below 50. For the post-injection periods, events with SNRs below 50 are still observed but at the same time, events with higher SNRs are also detected. In order to quantify the difference in the SNR distribution and magnitudes, we calculated the b-value for the injection and post-injection events. It is obvious that our b-values separate for the injection and post-injection events.

Conclusions

The study shows how detail analysis of microseismicity can help to understand the stimulation of the reservoir. Microseismic data sets are often very complex due to the complex reservoir and complex geomechanical coupling between injected fluid pressure and permeability of fractures. In order to separate microseismicity related to the different physical processes, various techniques combining microseismic, geomechanical, and engineering analyses are necessary. This data set is an outstanding example where microseismicity related to the hydraulic fracture and reactivation of pre-existing structures have clear signatures and as such can be used as a learning set to develop techniques.

The analysis of this data set presents clear evidence that microseismicity associated with hydraulic fracture differs from microseismicity associated with the reactivation of pre-existing structures:

1. The hydraulic fracture will propagate in the direction of SHmax, while the pre-existing structures will have different orientation.
2. Because of the orientation of structures in the stress field, the events related to the reactivation of the pre-existing structures will show bigger magnitudes and larger range of magnitudes.
3. Loss of fluids into the fracture system is detectable on engineering curves.

The analysis strongly suggests that some hydraulic fractures can be aseismic.

The presented integrated study improved our understanding of the well stimulation such that: overall, we almost doubled the number of hydrofractures and fault/fracture zones in comparison to the original interpretation based only on the microseismic mapping and we better constrained the half-lengths of the hydraulic fractures that has an important effect on the prediction of the well productivity.

Acknowledgements

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