Comparitive Microseismic Interpretation of Hydraulic Fractures

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Summary

Microseismic monitoring is often used to evaluate differences in hydraulic fracturing, that result from either changes in the stimulation or geologic setting. Often the various microseismic images of individual fracs are each separately interpreted for fracture geometry, and then these absolute interpretations of the various fracs are compared. However, comparisons can be made of variations in specific fracture dimensions between each image, including using statistical tests to quantify significance of relative differences. Such a relative comparative interpretation is more robust and relies on a simpler assessment of the location precision, in contrast to the need to consider all aspects of location accuracy for absolute interpretations. The resulting comparative microseismic interpretation can be used as part of a comparative hydraulic fracture evaluation to test the response to different designs and ultimately optimize the stimulation.

Introduction

Microseismic imaging of hydraulic fractures is a rapidly growing technology and is critical for optimized stimulation, particularly for unconventional reservoirs. Microseismicity associated with hydraulic fractures stimulations is used to interpret the frac geometry: including direction, height, length and complexity associated with interaction of pre-existing fractures. Often the interpreted geometries are used to compare fracs between different stages or different wells, in order to understand the impact of geologic setting and the engineering design of the stimulation. These observations are also a critical component to enable frac optimization, by comparing the results of different stimulation strategies to select the optimized design that creates a specific desired geometry.

Processing of microseismic data includes computing the hypocentral location of individual microseismic events, to create a collection of events representing the fracture growth. The extent of this 'cloud' of microseismic events is typically used as a measure of the frac geometry. To compare frac geometries, differences can be examined between *absolute* geometries of each frac determined in isolation from the other fracs. However, the *relative* differences between the two microseismic clouds can also potentially be directly compared. The distinction between such a relative versus absolute comparison is seen in a number of geophysical workflows: such as time lapse imaging where the difference between absolute images can be used although directly computing the relative difference image from changes in an attribute is typically more robust. In microseismic monitoring, relative comparison workflows include relative determinations of locations (e.g. joint hypocenter determination), mechanisms (relative moment tensors) and velocity structure (double difference local earthquake tomography). In each case, the approach of a relative determination is more accurate than the difference between two images. The same is true for comparing two microseismic images, where statistical significance tests can be made of relative differences in various aspects of the geometry (eg. height, length, etc). The object of this paper is to illustrate workflows that enable a comparison of the relative difference between two microseismic images, which has the advantage of providing a more confident interpretation of changes in microseismic response. These workflows therefore provide a key aspect for optimized hydraulic fracture stimulations to compare the microseismic response of different frac designs.

Comparison of the relative microseismic frac responses typically involve assessing if the fracture geometry or induced microseismic deformation differs. Interpretation of fracture geometry from microseismic data requires incorporation of the hypocentral accuracy, which includes both a precision component related to uncertainty in input data and an accuracy component related to potential systematic errors associated with the velocity model (Maxwell, 2009a). The precision is more important for relative interpretation of the fracture geometry, simplifying interpretation by avoiding the need to consider the absolute accuracy. For example, in a case of two proximal fracture images that tend to have similar accuracies (i.e. potential systematic location errors associated with the velocity model are the same in both cases), only the precision associated with input arrival times and directions need to be considered (Maxwell, 2009b). In other cases where the microseismic images do not share similar accuracies, the relative change in accuracy can be easily estimated. Furthermore, comparison of the microseismic deformation between data sets can be assessed by the number of microseismic events, or more robustly by the total microseismic source strength. Comparative interpretation of both geometry and activity rates are highlighted here using data examples.

Selecting Highest Quality Events

In order to compare microseismic images, it is important to select an accurate and representative data set with consistent data quality. The geometry of the microseismic cloud will be partially controlled by the data quality/location accuracy, with less accurate locations causing artificial blurring or spreading out of the extent of the microseismic cloud. A microseismic image contains events of variable signal amplitudes or SNR, with the majority of the events having low SNR. These low SNR events tend to be more uncertain and so a simple event selection filter is to consider only high SNR events. However, such filtering tends to significantly impact the number of events. The ability of this SNR filter to high grade the event data set has been described previously (e.g. Maxwell et al., 2010). An SNR filter can be extended to consider additional quality control attributes (Maxwell et al., 2007) such as confidence level defined as a score between 0 (min) and 5 (max) for contributing factors of p- and s-wave SNR, arrival time residuals and hodogram consistency. However a somewhat surprisingly effective parameter has been found to be an orthogonality index factor (OF). OF is defined here to be the average of the degree of orthogonality of the p- and s-wave, ranging from 0 (parallel) to 1 (orthogonal). As such the index is sensitive to SNR, phase consistency to avoid picking reflections and refractions modes, multiple interfering events and noise picking. As an example of application of an OF filter, consider an example previously used for a SNR filter (Maxwell et al., 2010). Figure 1 and 2 show a data set

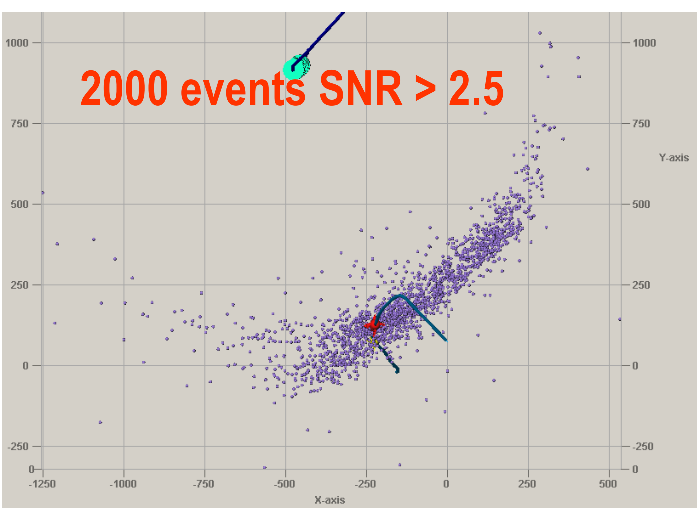

Figure 1. Map view of microseismic events from a hydraulic fracture.

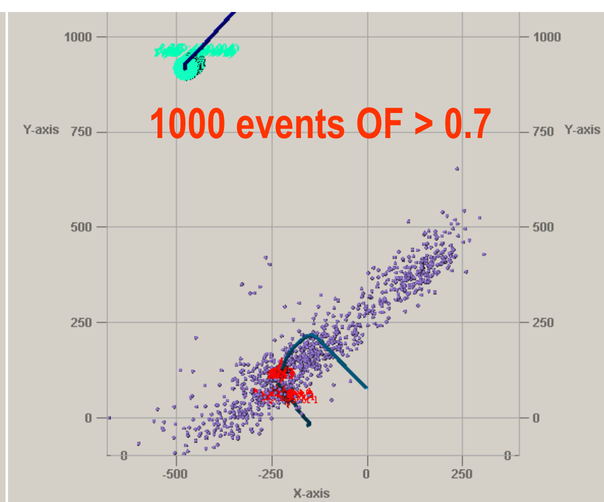

Figure 2. Same data set sorted for events with largest orthogonality Index factor (OF).

unfiltered and then filtered for OF. In this example 10% of the highest SNR were able to reproduce 'known' microseismic dimensions (see Maxwell, 2010 for further information and context of the known extent based on advanced processing). 50% of the highest OF were able to reproduce similar dimensions (Figure 2). To understand this difference in performance, consider Figure 3 showing statistical distribution of event attributes versus the known extent of the cloud. For both SNR and OF attributes the largest values indicate the known extent, while the lower values results in an overestimation. SNR attributes disregards numerous events in the correct zone in order to filter a sufficient level to remove the overestimation outliers. Alternatively, the OF distribution is such that fewer events in the lower tail of the distribution need to be disregarded to remove the overestimation outliers.

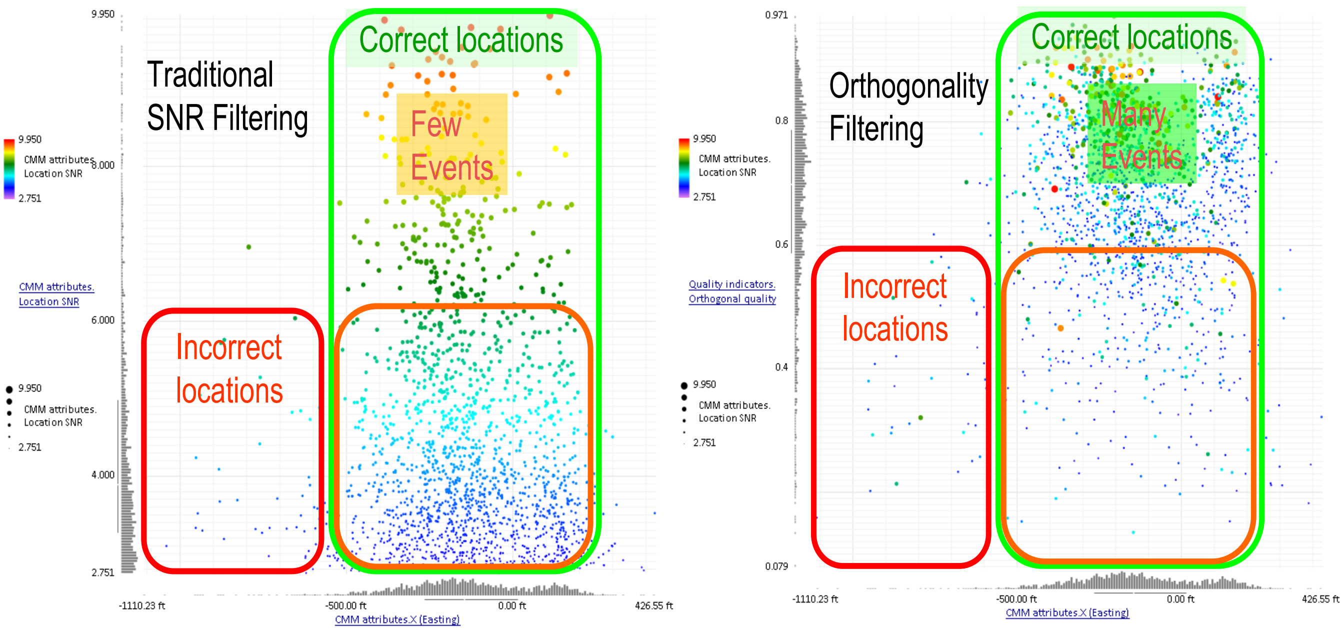

Figure 3. Crossplots of SNR (left) and orthogonality (right) versus position for data in Figs 1 and 2. For each the green rectangle shows the confident part of the microseismic locations, and the red and orange the correct and incorrect locations that would be filtered out with an appropriate filter.

Comparison of Hydraulic Fracture Geometry

The next step involves the comparative evaluation of the relative geometry, which will be demonstrated using microseismic from two stages in a multistage stimulation of a horizontal well in the Barnett Shale. One stage is approximately 700 m from the monitoring well and the other about 800 m (Figure 4). Microseismic locations estimated from an offset monitoring well along with an interpreted geometry encompassing 95% of the data are also shown. The event locations have been filtered for the best quality events. Note that among other aspects the more distant stage is slightly longer (transverse to the well), and that there is an overlap of almost 100 m between the two stages along the well. These simple observations amount to a comparative interpretation between these two stages based on a simple absolute interpretation of each stage. An improved interpretation can be made by directly comparing each aspect of the geometry by a statistical comparison with relative location errors.

First, the two stages are overlain with uncertainties in order to examine whether the slightly greater transverse length is significant. In this geometry, the location error in the transverse component of the frac is dominated by the geometric directional error from the single monitoring well, and is determined to be 4° on average for these events. This results in a 'cone' shape increasing with distance away from the monitoring well, as shown in the middle panel of Figure 4. The interpreted lengths both fall within these average uncertainty lengths, indicating that the interpreted extremes are consistent within location uncertainty. Therefore no significant differences in lengths are found between the two stages. Statistical significance tests between the interpreted geometries are not included here for the sake of brevity.

The final panel of Figure 4 shows the overlap in the stages with the average location uncertainty in the offset direction, as a function of radial orientation from the monitoring well. This offset uncertainty is controlled by the relative timing accuracy between the s- and p-waves, and is determined to be less than 20 m for this data. Therefore the observed overlap between stages is significant, and can be used as part of an engineering evaluation of the completion strategy. Stage overlap is an important aspect of optimization of multi-stages in horizontal wells, and can be used to assess if an adequate number of frac stages have been used. Evaluation of stage overlap involves considerations of a trade-off between favourable overlapping fracture network connection versus the potential negative consequences of closely spaced stages resulting in uneconomic overstimulation or even closure of fractures stimulated in earlier stages. Nevertheless, the observed overlap in this example appears excessive.

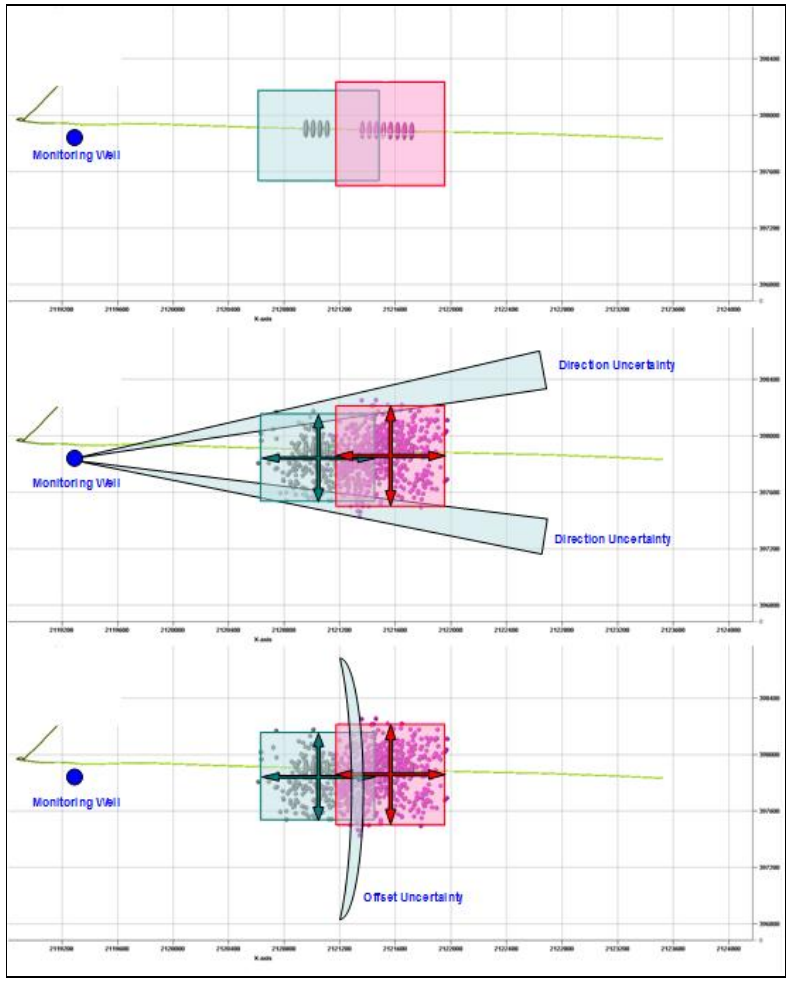

Figure 4. *Map view of two stages in a horizontal treatment well. Top panel perf locations and the interpreted extent of the microseismicity. Middle panel showing microseismic events and the location uncertainty associated with the direction to the microseismicity. Bottom panel shows the location uncertainty associated with the horizontal offset direction.*

Another common aspect of comparing microseismic images involves the relative number of microseismic events. While number of events is an appealing metric, measurement of the total microseismic source strength such as total seismic moment is more physically relevant. In order to compare either number or total moment, the sensitivity of the two arrays need to be consistent. Correcting for detection distance and potential source radiation effects are important to avoid spatial detection biases.

Designing a Comparative Evaluation Study

Often microseismic monitoring is used to evaluate the differences between stimulation methods. Consider the design of a hypothetical monitoring project to compare the fracture response of two or more different stimulation or completion designs. Prior to deciding the stages that are to be compared, it is critical to perform a pre-survey design study. Such design studies involve determining the minimum detectable magnitude and expected location accuracy at different positions, along with potential assessment of the expected number of detected events (Maxwell, 2011). The output of this design study is an expected range within which accurate microseismic results can be expected with a specific sensitivity. This range can then be used to identify the planned stages of the treatment well(s) that can be effectively monitored and compared. Figure 5 shows two conceptual completion and stimulation designs that could be undertaken for such a multi-treatment well project. The best scenario is to alternate designs within each well, and then apply the aforementioned comparative analysis. Not only are neighbouring stages most favourable for comparison, but such a design allows comparison between wells which could otherwise be complicated with geologic variations under a scenario where different designs were executed in different wells. An unfavourable fracture comparison is also depicted where the stages in the toe and heel of the well are varied, in which case comparison of the more distant fracs would not be expected to result in high quality microseismic data. Comparative interpretation would then be compromised.

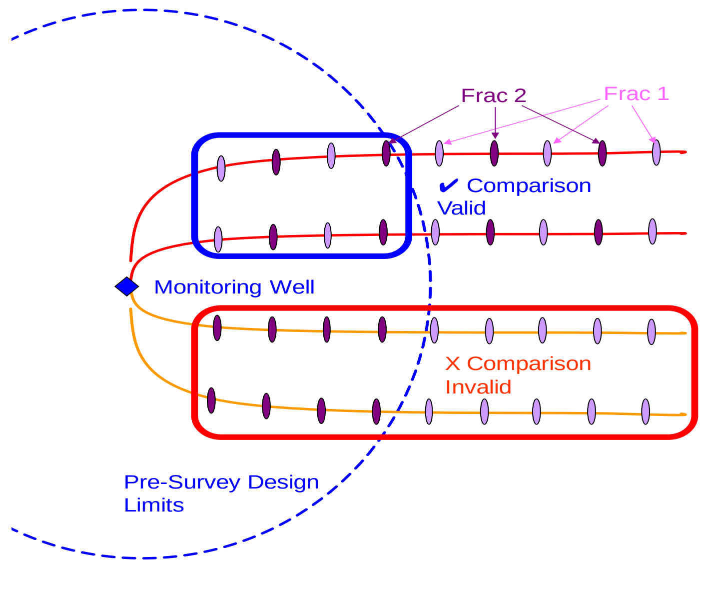

Figure 5. *Conceptual plot of an ideal treatment comparison (stages in blue box for top two wells) and non-ideal comparison (stages in red box for bottom two wells) for two different comparisons overlain with design limits from a pre-survey design study.*

Conclusions

A workflow is described for comparing microseismic images, both in terms of geometry and activity rates. Such a comparative interpretation looks for statistically significant differences and is more robust than comparing interpretations of each of the individual images separately. Comparing microseismic results enables optimization of hydraulic stimulations by comparing the resultant geometry associated with alternate fracture designs.

References

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