# Where Did the Proppant Go?

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## Introduction

Effective propped fracture half-lengths following a typical hydraulic fracture stimulation of a wellbore can be difficult to quantify. Therefore, different techniques for modeling proppant distributions must be applied to the same dataset for validation purposes and to gain insight into the actual proppant distributions. A proppant-filled Discrete Fracture Network (DFN) model (e.g. McKenna and Toohey, 2013) is applied to one well targeting the Evie Member of the Horn River Formation. Another technique for identifying microseismic signatures associated with the initial slickwater pad and the proppant-laden fluid (McKenna et al., 2012) was applied to the same two wells to obtain observed proppant distributions. The similarity of the proppant distributions from the two techniques gives validation to each procedure and the results can be used to optimize future completion techniques.

## Method

The study objective is to compare the proppant distributions using a proppant-filled DFN method to the observed proppant distributions using a technique to separate fluid-induced microseismicity from proppant-laden fluid-induced microseismicity to validate each technique. Proppant distributions (using both techniques) are broken up by their perpendicular, parallel, and vertical components with respect to microseismic distances from their respective stage centers. The distributions of each component are compared in terms of their mean values +/- one standard deviation.

## Results

Figure 1 shows the modeled propped and unpropped fractures of the example Evie well and figure 2 shows a histogram of proppant distribution using the DFN modeling approach with respect to the perpendicular distance from the stage center (black columns).

By tracking the microseismic centroid location throughout the treatment, we can identify engineering parameters that influence the location of the microseisms. The focus of this paper is on proppant placement, so we will only consider the influence of proppant concentration on microseismic location. Although proppant injection influences the microseismic location with respect to each of the three main components, its influence is especially apparent in the horizontal perpendicular component and will be the focus for this study. Figure 3 shows that prior to proppant-injection (slurry volume <600 $m^3$) microseismicity trends outward from the stage center. However, as bottom-hole proppant concentration increases (0-100 $kg/m^3$), microseismicity is located closer to the wellbore and the trend line is located closer to the wellbore. When proppant concentration is reduced after the first proppant ramp from 100 to 50 $kg/m^3$, the trend line grows back out further from the wellbore which is most apparent when slurry volume > 1000 $m^3$. Similarly, as the second proppant ramp increases in concentration, the trend line moves closer to the wellbore. Finally, after the second proppant ramp reaches a peak and is reduced to 60 $kg/m^3$, the trend line again moves further from the wellbore. This inverse relation between perpendicular growth of microseismicity and proppant concentration demonstrates that the event location is highly influenced by proppant concentration. In fact, after proppant is injected, the highest clustering of microseismicity occurs near the wellbore (<100 m) and occurs during highest proppant concentration. One explanation for this phenomena is that the initial slickwater pad (slurry volume < 600 $m^3$) is used to create an initial or reactivate an existing natural fracture network causing consistent outward microseismic growth as slurry volume increases. Then, as the proppant-laden slickwater is introduced (slurry volume > 600 $m^3$), proppant essentially fills the newly created fractures and microseismicity that is located close to the wellbore is possibly due to localized proppant clogging fractures resulting in rerouting of fluid causing near wellbore complexity or resulting in widening of fractures as the denser fluid fills the fractures and increases pumping pressure.

Figure 2 shows a histogram of microseismicity in terms of the horizontal perpendicular location with respect to the stage center (blue columns). In an attempt to visualize the microseismicity directly associated with proppant injection, we limit our data to only the events occurring during proppant injection and when slurry volume > 1000 $m^3$ (after trend line changes slope and begins to grow back toward the wellbore). The histogram shows a main peak close to the center of the stage center and two smaller peaks at approximately +/- 425 m. One hypothesis to explain this distribution is that the slickwater pad that is initially introduced when slurry volume < 600 $m^3$ propagates outward from the wellbore (Figure 1) and this front continues outward as the proppant is injected and remains out in front of the events due to proppant injection. If we assume that these two populations have a Gaussian distribution, we can roughly sketch out how these two populations are distributed. Interestingly, where the two populations (slickwater and proppant populations) overlap, there are smaller peaks indicating that both populations are overlapping. Using this technique, we can estimate the distributions of both the slickwater and the proppant populations.

## Conclusions

These propped fracture distributions can be used to evaluate current wellbore and stage spacing intervals. Results were within ~15% of one another. This suggests that when these two techniques are combined, the proppant distribution in a formation following a hydraulic fracture stimulation can be well constrained to yield good estimates. The results of the two models are used as a completions-diagnostics tool for evaluating the effectiveness of the stimulation and help make future completion techniques more efficient and economically more valuable.

## Acknowledgements

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### References

McKenna, J.P. and Toohey, N., 2013, A magnitude-based calibrated discrete fracture network methodology: First Break, v. 31:95-97.

McKenna, J.P., Bui, Q., Abbott, D. and Domalakes, D., 2013, Estimating event growth from pumped fluid volumes. Association of American Geologists National Meeting, Pittsburgh, PA, 19-22 May [2013] #156414.

Figures

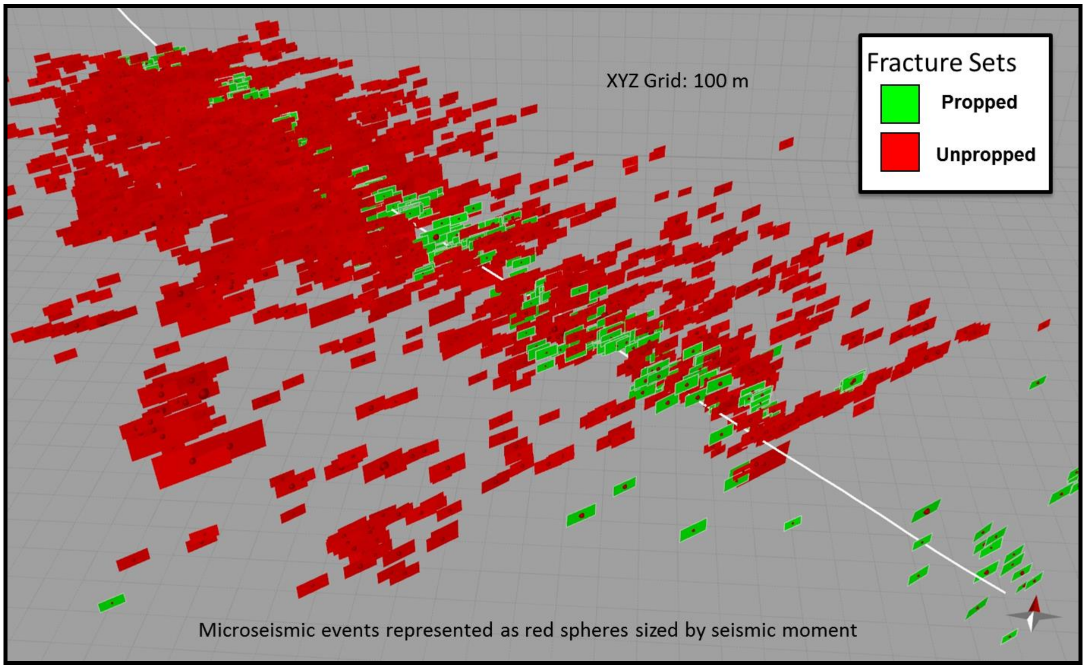


Fig. 1—Oblique view of modeled fractures. Fractures are oriented by focal mechanisms and colored green if propped and red if unpropped. Microseismic events are colored red and sized by seismic moment.

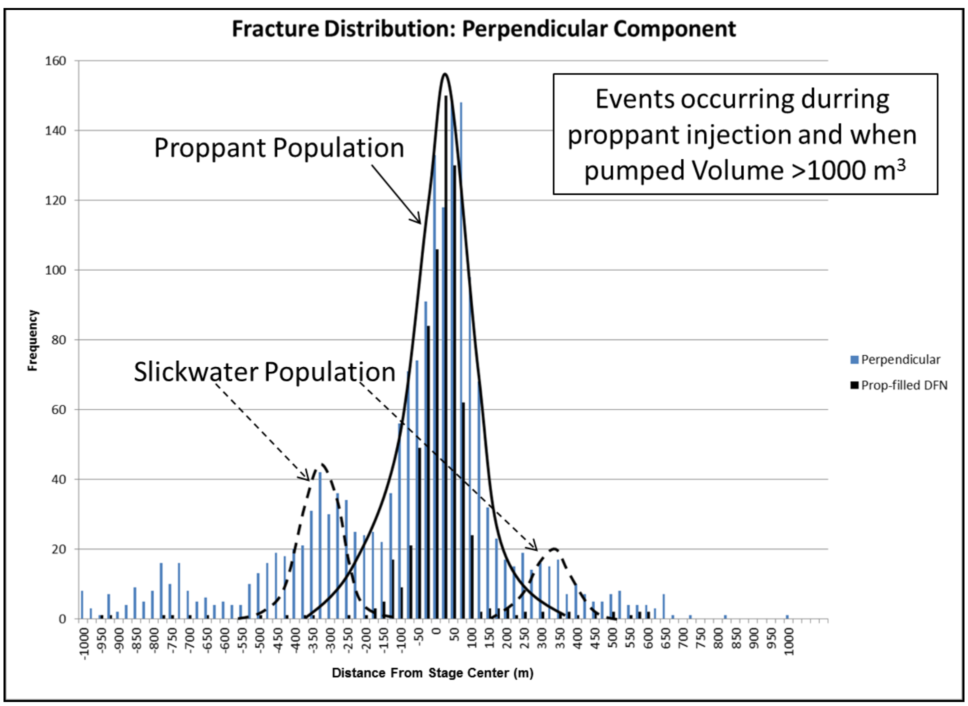


Fig. 2 – Comparison of proppant population where microseismic events are limited to events occurring during proppant injection and when pumped slurry volume is > 1000 m3 (blue histogram) to modeled proppant-filled Discrete Fracture Network (DFN) modeling approach (black histogram). Proppant population can be separated from slickwater population by assuming that two populations exist and are normally distributed.

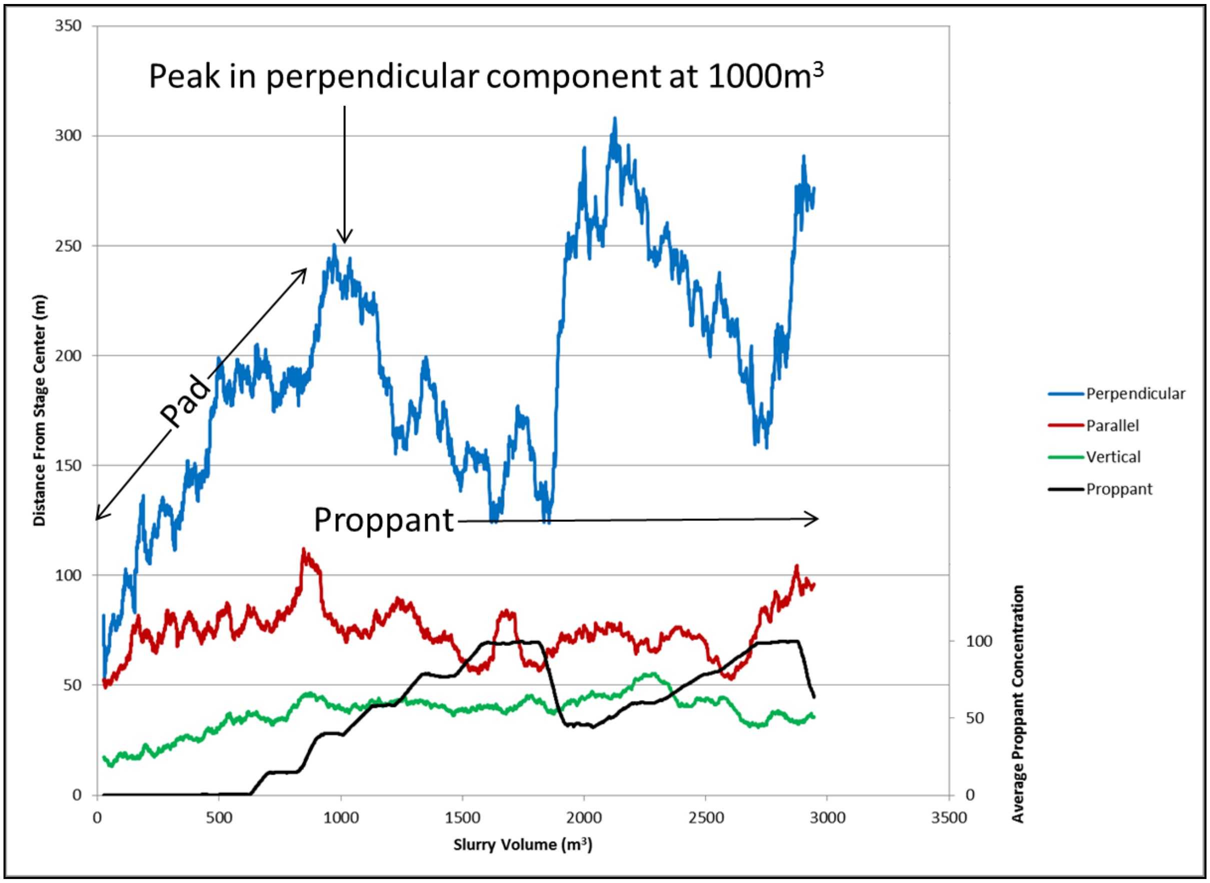


Fig. 3 – Microseismic growth broken up into perpendicular, parallel, and vertical distances from stage centers (primary y-axis) as a function of pumped volume (x-axis) and proppant concentration (secondary y-axis). Notice that the microseismic location is inversely correlated with proppant concentration indicating that microseismic signature is influenced by proppant injection. During the pad portion of the injection, microseismicity grows outward at a predictable rate from the wellbore reaching a peak in the perpendicular component at ~1000 $m^3$ and reaches a peak in the parallel and vertical components at ~850 $m^3$.