



## Microseismicity to production – what do we need to measure first?

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### Summary

Currently there are four widely discussed theories used to describe how microseismicity interacts with hydraulic fracturing. Each theory has a different implication for the interpretation of microseismicity used for reservoir modeling. Therefore, better understanding of the relationship between microseismicity and hydraulic fracture stimulation is needed before further reservoir models are developed and applied. This would lead to a more precise estimation of hydrocarbon production and give greater value to microseismic data. We may use either seismic or non-seismic methods. While non-seismic methods provide an independent view of hydraulic fracturing they only provide a limited amount of information on the relationship between hydraulic fracturing and microseismicity. We propose microseismic monitoring of directivity as the most promising way to determine the orientation of fault planes and associated slip vectors. Although this is a suitable method it requires sensors in multiple azimuths that are well coupled to obtain reliable high frequency signals. We suggest using Distributed Acoustic Sensing (DAS) sensors which are capable of sampling high frequency and may provide continuous data along long offsets at reasonable costs.

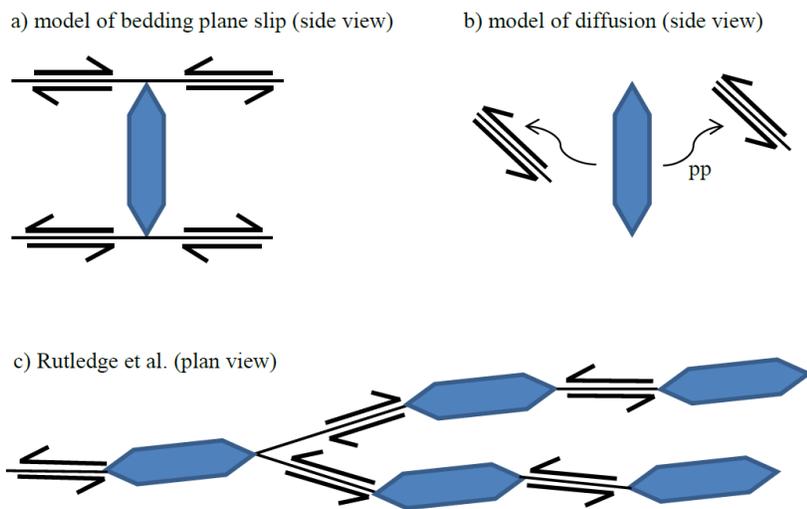
### Introduction

Hydraulic fracturing stimulation is accompanied by induced microseismic events resulting from the reactivation of pre-existing fractures or the creation of new fractures (e.g. Grechka and Heigl, 2017). Locations of microseismic events are then used to map the fracture geometry: the direction of fracture propagation, fracture length and height. Numerous authors and companies try to convert the measured microseismic information into estimations of reservoir production. These approaches use microseismicity to constrain linear and non-linear diffusion (e.g., Grechka et al., 2010), discrete fracture networks (Williams-Stroud et al., 2013), tensile opening of hydraulic fracture (Baig and Urbancic, 2010), or bedding plane slip (Rutledge et al., 2013, Stanek and Eisner, 2013). Many of these approaches try to directly map microseismicity to production prediction and other highly valuable information but the reality of the current state of the art is that we do not know the exact nature of microseismicity and hydraulic fracture interaction with microseismicity. Therefore, many of the reservoir simulators based on microseismicity are subject to significant uncertainty.

An important role in the determination of interaction between microseismicity and hydraulic fracture may be determined by better constraining the seismic signals and removing part of the uncertainty from both microseismic locations and additional information contained in the recorded seismic signal – the source mechanisms. Specifically, we may exclude some of the above-mentioned models if our inverted data is more precise or at least more accurate. Microseismic locations are often interpreted as a diffused cloud of widely activated fracture networks, while misinterpreting location errors with diffusion process (e.g. initial locations in Rutledge and Phillips, 2003). Similarly, there are doubts as to whether the non-shear components of microseismic events induced by hydraulic fracturing are real or the result of erroneous processing (e.g. differences in observation of Baig and Urbancic (2010) and Grechka et al. (2016) vs Staněk and Eisner (2017)). The main challenge in improving downhole acquired microseismic locations is downhole velocity model as wave propagation along horizontal layers is not suitable for commonly used ray tracing methodologies (e.g., Klimeš, 2012) and the high frequency content of recorded waveforms is compromised with trapped waves and clamping issues resulting in poor azimuthal measurements (e.g.

Janská et al., 2014). Additionally poor azimuthal measurements as a result a single vertical monitoring borehole must be resolved with multiple monitoring boreholes or lateral array. Surface monitoring is usually compromised by relatively high levels of noise and lack of high frequency content as it is attenuated along a path to the surface.

The above-mentioned models of the interaction between microseismicity and hydraulic fracture result in different constraints to the reservoir model. i.e., the same observed seismicity must be interpreted based



on the true interaction between hydraulic fracture and microseismicity. Here we discuss what kinds of monitoring can find the true model representing the nature of interaction and develop a more realistic interpretation of microseismic events with greater hopes of matching the production. For example, the bedding plane interpretation of microseismicity allows assessment of the amount of the hydraulic fracture opening as illustrated in Figure 1a. If this model is valid, seismic moment of a microseismic event is proportional to fracture width. If the diffusion model is right, the width of the microseismic

cloud provides important constraint of pore pressure changes in the formation (see Figure 1b as illustration) and such pore pressure changes can be then used to predict production as they inform us on penetration of fluids through the formation. If the model of Rutledge et al. (2004) illustrated in Figure 1c is valid microseismic events represent choke points of the hydraulic fractures and their seismic moments represent minimum spatial extend of the hydraulic fracture as they are part of the hydraulic fractures. An Alternative model of Eisner et al. (2010) explains hydraulic fracture as an opening of a horizontal fracture overcoming vertical stress and microseismicity is shearing almost vertical planes. That would mean that we could measure height of opened fracture from seismic moment of microseismic events. The least widely discussed model interprets microseismic events as tensile opening and closing. Microseismic events are interpreted as a direct result of fracture opening close to the injection points combined with shearing away the injection. Such seismicity is characteristic with variable orientation of events as it is a random reaction of the reservoir to the stress changes.

**Figure 1** Commonly accepted models of induced seismicity: a) model of bedding plane slip, b) model of diffusion (linear), c) model of Rutledge et al., 2004 (plan view).

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Luckily, the above-mentioned models predict differences in observed data and we may be able to differentiate among them if sufficiently good datasets are acquired. In this study, we discuss what needs to be measured before the models are used for quantitative and qualitative production prediction, we want to discuss what kind of acquisition is needed to be able to differentiate between the proposed models and how to acquire such data.

### What can be done

It is possible to drill and core the fractured area close to the treatment well where the microseismic events occur. In some circumstances, it is even possible to imagine a mine back experiment where the fractured area mined back (like potash mines experiments – Warpinski et al. 1981). In such experiments, it would be desirable to trace (chemical or other) the injected fluids. Core sample from such a well could help us to

understand where the fracturing fluid really penetrated and certainly it would differentiate between wet and dry fractures. However, there are two very fundamental problems associated with this experiment:

- It is extremely difficult to drill through the fault plane of a microseismic event given the uncertainties of the locations of these microseismic events
- Even if we were able to drill precisely into the fractured area, we can't distinguish between fracture opened seismically and aseismically.

This experiment would only provide local and incomplete information about the interaction of hydraulic fracturing and microseismicity.

Alternatively, we may use a network of sensitive borehole tiltmeters in the close vicinity of the fractured area combined with microseismic monitoring. Note that tiltmeters are sensitive to the volumetric changes due to the hydraulic fracture. Temporal interpretation of tiltmeter changes combined with space and temporal information on microseismic events could provide us a much better understanding of which microseismic events are part of the hydraulic fracture and which events are results of stress changes without volumetric fluid changes. Specifically, we would be able to differentiate between vertical and horizontal hydraulic fractures. Implicitly this would imply which microseismic fault planes are activated by the hydraulic opening. However, uncertainty of inversion of tiltmeter signals grows rapidly with distance from the sensors as the inversion of tiltmeter signals suffers from a large degree of uncertainty resulting from unknown geomechanical properties of the rock formation. Additionally, it would be hard to install tiltmeters in the vicinity around the hydraulic fracture area which would be necessary to constrain the hydraulic fracture image.

As the non-seismic methods seem to have significant drawbacks we turn back to induced seismicity monitoring and interpretation. For example, in seismology there are at least three options on how to overcome uncertainty of differentiation between the fault and the auxiliary planes in the far field approximation:

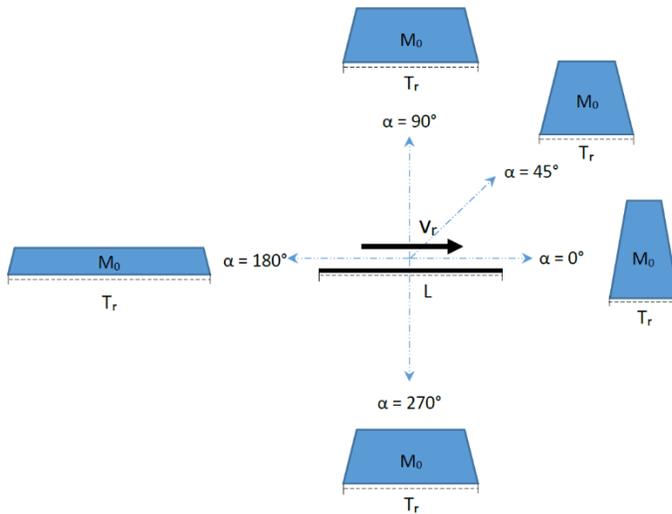
1. Directivity – the use of a ‘Doppler effect’ of seismic waves also known as the Haskell model of seismic source directivity. This model uses the anisotropy of the radiated energy to differentiate between fault and the auxiliary planes.
2. Locations of aftershocks: aftershocks are usually distributed along the fault, not the auxiliary plane of the earthquake.
3. Differentiation between hypocenter (point where the fault started to slip) and the centroid (point where most of the seismic energy is radiated) of an earthquake. Fault plane contains both points while auxiliary plane only contains one of them if at all.

The Location of aftershocks and hypocenter-centroid methods both require high precision and accuracy of the located events and hypocenter especially in relative positioning resulting in significant subjectivity of results. Let us discuss in more details the directivity as this method uses the anisotropy of far-field seismic energy.

The Haskell model is the simplest representative of this model. The low frequency duration of far-field unilateral Haskell type of fault plane rupture forecasts that the duration time of source rupture is

$$T_r = L \left( \frac{1}{v_r} - \frac{\cos \alpha}{v_s} \right) \quad (1)$$

where  $v_r$  is rupture velocity,  $v_s$  is velocity in the source area,  $L$  is the length of the rupture and  $\alpha$  is the angle between receiver and the slip vector (as shown in Figure 2). For an estimate of the rupture length 1 m, the S-wave velocity 2500 m/s and the rupture velocity 80% of the S-wave velocity, the difference apparent rupture time  $T_r$  between the receiver in the direction of the slip vector and in the opposite direction is approximately 0.0005 s, i.e. one half of a millisecond. Such small difference implies at least two challenges for microseismic monitoring:



Surface monitoring unless extremely shallow is unlikely to sample signal energy at the frequencies above 100 Hz because it is attenuated.

Downhole instrumentation must be cemented behind the casing as in the seismic waves at the frequencies above 200-300 Hz interacts with borehole fluids and therefore the measurement of instruments clamped inside the borehole is compromised. Additionally, it is well known that the instruments have internal coupling resonances at those frequencies, again making the uncemented coupling highly questionable and not suitable to measure amplitude information.

**Figure 2** Source time function of radiated pulse in different azimuths relative to slip vector ( $v_r$ ).

Therefore, we conclude that only downhole sensors cemented behind casing in several azimuths are likely to sample well enough the seismic signals to differentiate between the discussed models. This experiment would also be extremely expensive to conduct.

Distributed Acoustic Sensing (DAS) sensors may be suitable for directivity resolution and are already developed and readily available: (e.g., Hull et al., 2017; Karrenbach et al., 2017; Starr and Jacobi, 2017). These DAS sensors can be bonded to the casing in the horizontal sections of the boreholes sufficiently close to microseismic events to record the effects of directivity. With DAS it is possible to measure the strain changes continuously and in real time at acoustic frequencies of several MHz. This means we can achieve sufficient sampling resolution along the entire horizontal section of a well which can be several kilometers in length. The only drawback is the relatively short distance (approximately less than 50 m) between events and sensors to see the radiation directivity.

### Conclusions

Currently we have at least four competing theories on how microseismicity interacts with hydraulic fracturing. These theories have vastly different implications for interpretation of microseismicity in reservoir modeling. Therefore, a more precise understanding of microseismicity and hydraulic fracturing is needed before further reservoir models are developed and applied. Non-seismic methods provide limited understanding on which model is right. Seismic monitoring of directivity seems to be the most suitable but requires sensors in multiple azimuths that are cemented behind the casing due to high frequency signals. We suggest that the DAS sensors may provide the most promising sensitivity which could lead to differentiation among the proposed models and new improvement of reservoir simulators based on microseismicity.

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