Introduction

In this paper we investigate the physical mechanisms responsible for triggering felt seismicity during hydraulic fracturing of the Preston New Road PNR-1 well in October – December 2018 (Clarke et al., 2019; Kettlety et al., 2020). This site was the first to undergo hydraulic fracturing in the UK since the conclusion of a government review in 2012, and as such was the subject of significant public and governmental scrutiny. With high-quality microseismic data from downhole and surface monitoring, this site provides an excellent opportunity to examine in detail the processes that occur when hydraulic fractures intersect a pre-existing fault.

Hydraulic fracturing-induced seismicity (HF-IS) is typically understood in terms of the Mohr Coulomb friction acting on faults, where the fault will slip if the shear stress (τ) acting on the fault exceeds:

\[ \tau > \phi (\sigma_n - P) + C, \]

where \( \sigma_n \) is the normal stress, \( P \) is the pore pressure, \( \phi \) is the coefficient of friction, and \( C \) is the cohesion. Equation 1 can be re-written in terms of the change in Coulomb Failure Stress (ΔCFS):

\[ \Delta CFS = \Delta \tau - \phi (\Delta \sigma_n - \Delta P), \]

where a positive ΔCFS implies the stress has changed such that the fault has been moved towards failure, increasing the likelihood of induced seismicity.

The CFS will be increased by an increase in pore pressure during stimulation, and this is usually considered to be the main causative mechanism of HF-IS. Shale rocks have low permeability, which means that it will take a long time for pore pressure perturbations to move a significant distance from the well (more than a few hundred metres in most cases). The spatiotemporal distribution of microseismic events suggests that alternative mechanisms may also play a role in triggering HF-IS (e.g., Bao and Eaton, 2016; Deng et al., 2016; Verdon et al., 2019). Verdon et al. (2019) have demonstrated that pre-existing fracture corridors may provide a permeable pathway, enabling pressure perturbations to reach larger distances than might otherwise be expected given typical shale permeabilities. Alternatively, Deng et al. (2016) showed that poroelastic stress transfer caused by the pore pressure increase could generate positive ΔCFS changes, triggering events at greater distances.

![Image of events recorded at PNR-1 with \( M_w \) larger than -0.5, coloured by the associated stage number and sized by magnitude. The black lines show the wellbore tracks, and the diamonds show the PNR-Iz injection intervals. The shaded rectangle shows the position of the reactivated fault. Focal mechanisms for larger events are also shown.](image)

One possibility that has heretofore not been considered is the elastostatic stress transfer caused by the tensile opening of hydraulic fractures themselves. Hydraulic fractures typically open by several mm during hydraulic fracturing, and this deformation will impart elastic stress onto the surrounding rock. If these stress changes act to increase \( \tau \), or to decrease \( \sigma_n \) acting on a pre-existing fault, this can control the triggering of induced seismicity. Analogous effects have been observed associated with tensile...
opening of dykes controlling the distribution of seismicity in volcanic settings (e.g., Green et al., 2015). Here we develop stochastic models of hydraulic fracture opening and simulate the resulting $\Delta CFS$ changes to investigate whether these effects play a role in controlling the distribution of events during stimulation of the PNR-1 well.

**Dataset**

The PNR-1z well was drilled into the Carboniferous Bowland Shale in Lancashire, NW England, and hydraulically fractured in October – December 2018. The lateral portion of the well extends 780 m in a westward direction, with 41 individual injection sleeves. Microseismicity was monitored using a combined array of 24 downhole geophones in an adjacent well, and a surface array of 8 sensors (see Clarke et al., 2019, for more details). These arrays detected in total over 38,000 events ranging in magnitude from $-3 < M < 1.5$. The stimulation was conducted following the UK’s Traffic Light Scheme, where the red-light threshold is set at $M = 0.5$, whereupon the operator must pause for 18 hours before continuing. This red-light threshold was exceeded multiple times during stimulation, limiting operations such that only 17 of the planned 41 stages were completed. Injected volumes and proppant loads were frequently reduced from the planned 400 m$^3$ of fluid and 50 tonnes of proppant (Clarke et al., 2019).

Clarke et al. (2019) used the microseismic event locations to identify a pre-existing fault zone that was reactivated during stimulation (Figure 1). This near-vertical fault runs to the NE at an oblique angle to the well, with a strike of 230° and a dip of 70°, and so was intersected by multiple stages along the well, leading to repeated triggering of seismicity. This orientation matches the focal mechanisms of most of the larger events that occurred (Figure 1).

**Modelling Mohr Coulomb Stress Transfer**

To produce the loading, or sources, for our stress transfer simulations, we require estimates for the number of hydraulic fractures, their orientation, length, height, and the amount of tensile opening that takes place. This could be done using coupled hydro-mechanical codes. However, such models are dependent on poorly constrained geomechanical input parameters, which may be tuned based on observations during operations. Modelling of this kind is beyond the scope of this study, which aims not to model the hydraulic fractures themselves, but the effects of the fractures on the surrounding rocks. Instead therefore we require less complex models for the growth of hydraulic fractures.

We achieve this using a stochastic approach: rather than generating a single fracture set realisation, we generate thousands of models by drawing the relevant fracture parameters from statistical distributions representing typical hydraulic fracturing cases. By drawing the median results from such stochastic model populations, we can establish the typical changes in stress imparted by opening hydraulic fractures in the surrounding rock, without being tied to a single, specific model instantiation of the fractures.

The statistical distributions from which we draw our fracture parameters are as follows. The lateral and vertical positions of the fractures are assumed to be normally distributed around the injection point, with a standard deviation of 25 m. The fractures are modelled as near-vertical, uniformly-opening patches, with orientations sampled from a Von Mises distribution with an average strike of 170° (the maximum horizontal stress direction) and a standard deviation of 10°. Based on the spatial distribution of microseismic events (Clarke et al., 2019), we randomly select 80% of the fractures to propagate northwards, and 20% to propagate to the south of the well. The fracture lengths are normally distributed with a mean of 25 m, a standard deviation of 50 m, a maximum length of 250 m and a minimum length of 15 m. All fractures have a fixed aspect ratio of 0.2. The number of fractures is set such that the total injected volume for each stage matches the total volume of the fractures, with values for fracture opening taken from analytical solutions for the opening of a Griffith crack (Perkins and Kern, 1961).

For each fracture model realisation, we compute the $\Delta CFS$ change onto the orientation of the identified fault, using the PSCMP code of Wang et al., 2006. We then use the median $\Delta CFS$ values at each point in the volume around the well from the 1,000 model fracture set realisations. For each hydraulic fracturing stage, we consider 3 scenarios – the $\Delta CFS$ values from all previous stages prior to the stage.
under consideration, the $\Delta CFS$ values from the stage under consideration, and the combined effect of all previous stages plus the current stage.

To assess the significance of the elastostatic stress transfer effect, we compute $\Delta CFS$ values at the location of every event during the stage under consideration. If stress transfer were playing a significant effect then we would expect to find the majority of events occurring in regions of positive $\Delta CFS$, with seismicity suppressed in regions of negative $\Delta CFS$. We therefore compute the Coulomb Index, CI, which describes the proportion of events in positive $\Delta CFS$ lobes. If elastostatic stress transfer is significant then the CI will be high (typically $> 70\%$), while if this effect is not significant then we would expect a CI of 50 % (events occurring equally in positive and negative $\Delta CFS$ lobes).

**Results**

Figure 2 shows an example of our results for two selected stages. Microseismic events are mapped and coloured by whether they occur in positive (red) or negative (blue) $\Delta CFS$ lobes. We find that the majority of events do in fact occur in positive $\Delta CFS$ lobes, implying that elastostatic stress transfer is playing a significant role in determining where fault reactivation occurs.

![Figure 2 Example maps of modelled $\Delta CFS$ changes (for Stages 22 and 38), with events (circles) coloured by the $\Delta CFS$ they receive. The majority of events occur within lobes of positive $\Delta CFS$ and are suppressed in regions with negative $\Delta CFS$.](image)

This correlation between positive $\Delta CFS$ and event locations is common to most of the injection stages. Figure 3 shows CI values for each stage, showing values using computed using (a) deformation from the stage in question, (b) deformation from prior stages, and (c) a combination of current and prior stages. We find that CI values are elevated ($> 70 \%$) for many stages, but in particular for stages that showed evidence for fault reactivation, such as stages 2 and 3, and then the stages towards the heel of the well (from Stages 18 onwards).

The CI for Stage 18 is particularly high ($> 80\%$) – this stage produced a very large amount of seismicity relative to a very small injection volume ($\sim$1200 events for $< 10$ m$^3$ injected). This behaviour can be considered in light of the observed $\Delta CFS$ created by the tensile opening of hydraulic fractures during the previous stages. The deformation acted to increase the shear stress in the fault zone (increasing $\Delta CFS$), such that it re-activated very strongly when intersected by the very small injected volume during Stage 18.

Similarly, the $\Delta CFS$ effects are prominent for stages towards the heel of the well, especially when current and prior stages are considered in combination. The net effect of repeated tensile opening of fractures along the well builds and reinforces a lobe of positive $\Delta CFS$ that propagates to the NE of the stimulated zone, which happens to be where the fault runs (Figure 3). Therefore, the tensile opening from earlier stages is pre-stressing the fault to reactivate further as stages move from toe to heel along the well to the east. It is in these stages near the heel that the largest events occurred, towards the end of the stimulation.

**Conclusions**

The strong correlation between microseismic events and lobes of positive $\Delta CFS$ indicates that fault reactivation at the PNR-1 well is not solely controlled by hydraulic fluid pressures, but that the effects
of tensile fracture opening on the surrounding stress field also controls where the fault reactivated. This is, to our knowledge, the first time that such elastostatic stress transfer effects have been observed during hydraulic fracturing-induced seismicity, although they are well established in other, tectonic and volcanic settings (e.g., Green et al., 2015).

These effects will be highly dependent on the specific orientations of both the hydraulic fractures and the receiving faults, and so cannot easily be generalised to other sites. However, the stochastic modelling approach, combined with the PSCM modelling code, is able to provide results at a speed that could plausibly be applied in near real time during injection operations. Doing so could enable operators to identify whether their planned stimulation program is likely to stress or to clamp any faults identified before or during injection, and potentially to make appropriate adjustments to their program to minimise induced seismicity.

![Figure 3 Coulomb Index](image)

**Figure 3** Coulomb Index (proportion of events occurring in positive ΔCFS lobes), when modelling: (a) the current stage; (b) all stages prior to the current stage; and (c) combining the effects of current and previous stages. CI values are mostly above 50%, with many cases being above 70%, especially when the cumulative impact of multiple stages is considered.

References