DAS microseismic reflection imaging for hydraulic fracture and fault zone mapping

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Summary

This study presents a novel approach for 3D fracture imaging using microseismic reflections recorded by Distributed Acoustic Sensing (DAS). The imaging technique treats microseismic events as high-frequency sources and applies prestack Kirchhoff migration to each individual source after wavefield separation. Fracture imaging results for multiple selected events are then stacked to generate a 3D reflectivity volume, revealing subsurface fracture and fault networks. The method is immune to any simplifications about fracture geometry and provides high-resolution images, illuminating the heart of the stimulated volume of the reservoir that is inaccessible using typical surface arrays. We apply the proposed workflow to a dataset acquired during a multi-well project in the Eagle Ford Shale and Austin Chalk in South Texas and compare it with microseismic clouds and low-frequency DAS measurements. The results of reflection imaging improves our understanding of fracture geometry and pre-existing fault lineaments.

Introduction

Microseismic monitoring has proven to be a highly effective approach for direct surveillance of fracture extent and geometry. The microseismic catalog and event “clouds”, which combine information such as origin time, hypocentral location, magnitude, and potentially source mechanism, aid in inferring fracture orientation, revealing fracture system connectivity, and estimating stimulated volume and rock properties (Maxwell, 2014). Analyzing induced and natural seismicity provides valuable insights into the spatial relationship between seismic events and large-scale faults and other geological structures (Eaton, 2018). However, microseismic measurements only provide information on where the rock volume breaks and hence are incapable of resolving existing fault lineaments that have yet to be activated or fracture components which deform aseismically.

Another potential application of microseismic data involves utilizing the microseismic events as high-frequency sources for reflection imaging. Compared to active seismic imaging using surface sources, microseismic reflection imaging offers the benefit of having sources located within the stimulated volume and in close proximity to sensors, resulting in higher frequency and resolution over surface arrays. Several case studies have demonstrated the observation of reflected waves using 3C geophone arrays and the direct application of existing imaging methods to microseismic data (Chavarria et al., 2003; Dyer et al., 2008; Lin and Zhang, 2016; Grechka et al., 2017). However, the efficacy of this approach has historically been constrained by the sparse distribution of borehole seismic sensors. The irregular spatial distribution of microseismic sources presents another challenge, as passive sources lack control like active sources.

Distributed Acoustic Sensing (DAS) has increasingly been used in recent years for a wide range of applications during hydraulic fracturing operations. Low-frequency DAS (LF-DAS) is capable of measuring cross-well strain changes that enable the direct observation of fractures intersecting the monitoring fiber (Jin and Roy, 2017; Zhang et al., 2020). DAS systems offer many advantages over traditional arrays, despite being limited to measuring only a single (axial) component of strain or strain-rate changes along the fiber. Fibers can be km to tens of km long, providing high spatial resolution (below 1 m) and broadband frequency (from mHz to kHz) monitoring of the entire well. For microseismic monitoring (Karrenbach et al., 2019), the dense spatial sampling of DAS recordings provides rich wavefields with a large aperture, facilitating detailed observation of subsurface wave propagation and the application of advanced processing and imaging algorithms. Several attempts (Stanek et al., 2022; Ma et al., 2022) have explored the possibility of using DAS microseismic reflections for hydraulic fracture mapping. However, current workflows are limited to assumptions regarding fracture geometry and thus only provide 2D maps rather than a comprehensive 3D image volume.

In this study, we develop a workflow to image hydraulic fractures and fault lineaments using DAS-recorded microseismic reflections. First, we document DAS microseismic reflections acquired during a multi-well project. Then, we apply a pre-stack Kirchhoff migration workflow to image fractures in 3D after wavefield separation. Imaging results are integrated with microseismic clouds and LF-DAS to verify the fracture geometry. The 3D fracture imaging volume reveals the fracture geometry generated by fluid injection beyond the monitoring well. Finally, we demonstrate the potential of employing fracture images generated from multiple events to monitor and track the dynamic evolution of fractures.

Dataset and microseismic observations
Fracture Imaging using DAS-Recorded Microseismic Reflections

The DAS data used in this study were acquired as part of a multi-well project conducted in the Eagle Ford Shale and Austin Chalk in South Texas (Figure 1). A zipper-fracturing completion was performed on two horizontal wells, notated in this study as Well 3 and Well 5. Two standard single-mode fibers, capable of supporting DAS, DSS, and Distributed Temperature Sensing (DTS) measurements, were permanently deployed in both wells for hydraulic fracture monitoring. The raw DAS microseismic data were collected by a commercial DAS IU using a gauge length of 10 m and a spatial interval of 1.0 m, with a frequency sampling rate of 1000 Hz. The microseismic wavefields and reflections propagate toward the heel of the well (right dip), potentially generated by seismic waves that are emitted from microseismic sources and then impinge on nearby hydraulic fractures. Since the reservoir was stimulated from the toe side of both wells, reflections with the opposite dip (i.e., propagating toward the toe side) likely originate from pre-existing nearby fault lineaments, which is supported by the imaging results as well. Considering the relatively weak signal from the vertical section of the fiber, only the horizontal section of Well 3 (3130 traces for each source) was used for migration after removing bad traces.

**Imaging methods**

We treat each microseismic event as a high-frequency seismic source, consider each fiber channel as a receiver, and apply a pre-stack Kirchhoff migration method for reflection imaging after wavefield separation. The proposed method requires accurate microseismic event locations, the well geometry, a calibrated velocity model, and unclipped microseismic waveforms.

After analyzing the microseismic catalog obtained by a dense large aperture surface array (2653 events grey dots in Figure 1), over two hundred relatively large events (Mw ≥ 1.50) captured fracture- or fault-reflected S-waves (blue dots in Figure 1). To mitigate the potential impact of high noise levels in low signal-to-noise (S/N) events on the final image quality, we chose to decimate the available microseismic event catalog and selected 100 events with the best-quality reflections (red circles in Figure 1) for imaging.

To extract reflected S-waves from the raw DAS data, we apply a bandpass filter with a frequency range of 15-200 Hz to attenuate noise and an f-k filter for wavefield separation. Direct waves are then muted for each source. We utilize a calibrated S-wave velocity model (Figure 1c) to compute a travelt ime table, then migrate the microseismic traces and output an S-wave image volume on a 10 × 10 × 10 m grid. Due to

![Figure 1: Data overview. Fibers are permanently installed in two horizontal wells, Well 3 and Well 5, to monitor hydraulic fracturing. A microseismic catalog by the surface array is shown in (a) map view and (b) side view. (c) The layered isotropic velocity model for imaging.](image_url)

![Figure 2: Two examples of observed microseismic wavefield with fault- and fracture-reflected waves recorded by fiber in Well 3, (a) Event A and (b) Event B.](image_url)
Fracture Imaging using DAS-Recorded Microseismic Reflections

the limited depth constraints provided by microseismic reflections, only a depth range of 300 m within the fracturing zone was imaged (as shown by the red mask in Figure 1b). Conventional 3D pre-stack Kirchhoff migration is applied separately to the wavefields propagating towards the toe and towards the heel of the lateral, an approach which minimizes image errors caused by incomplete removal of direct waves and ensures thorough quality control to achieve accurate and reliable migrated volumes.

The Kirchhoff migration images for two individual events (Figure 2) are presented in Figure 3, with a horizontal slice at the depth within the fracturing zone (marked by the red dashed line in Figure 1b). Due to the geometry of unevenly distributed microseismic sources and the oriented DAS array, different sources may illuminate different parts of the reservoir. In Figure 3a, the image of Event A characterizes most of the cross-well fractures from previous stages. The absence of reflectors near the toe side from early stages is caused by the lack of available data resulting from fiber breakage, as shown in the raw data (Figure 2a). In contrast, Event B in Figure 3b reveals the structure of far-field faults that likely take stimulation fluid, as well as a portion of the cross-well fracture growth.

Imaging results

After imaging individual sources, all detected reflectors are stacked into a 3D reflectivity volume, enabling the delineation of multiple discrete reflectors. To mitigate the influence of varying magnitudes and focal mechanisms of different sources on stacking, we adopt a normalization step to all images of every single shot, which are then combined by taking their absolute values to build the 3D image volume. While this straightforward workflow may accumulate image noise and slightly decrease the resolution, it effectively prevents the cancellation of useful contributions from sources with opposite polarities at the same image point. A median filter is also applied at the last step of the imaging workflow to remove background noise.

Another challenge of microseismic imaging is the irregular distribution of microseismic sources and subsurface reflection fold, unlike active source imaging with a specifically designed geometry to target a particular subsurface objective. In cases where a microseismic cluster is significantly denser than others and illuminates a very similar volume multiple times, stacking individual sources with equal weights can generate strong artifacts and obscure weaker reflectors. To attenuate imaging artifacts caused by the irregularity of microseismic sources, we spatially classify selected sources into different clusters based on their hypocenter locations and assign equal weights to each cluster instead of each source. It should be noted that a trade-off exists between the aperture and image S/N ratio due to the irregular spatial fold of the reflection geometry, particularly in subsurface regions with fewer large microseismic events.

Figure 4 demonstrates the imaging results obtained by stacking 100 microseismic sources with a horizontal slice at the same depth of Figure 3 (the red dashed line in Figure 1b). Microseismic clouds and frac-hits interpreted by LF-DAS are overlain on the slice for further validation. Figure 4 exhibits the expected imaging artifacts due to the narrow aperture and residual direct waves indicated by white arrows, but it also presents considerable interpretable features, which is a promising outcome. Reflection imaging provides a high-
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Figure 5: Vertical slice through 3D seismic image volume along the fiber in (a) Well 3 and (b) Well 5.

resolution map of subsurface reflectivity, expanding the understanding of fracture geometry identified by microseismic clouds. Due to strong noise produced by in-well injection, only frac hits from early stages are accurately picked (white dots), where unfortunately most reflected waves are lost due to fiber breakage in a later treatment stage of Well 3. Despite this, two frac hits from the last interpretable stage, marked by a red arrow in Figure 4, are well-matched with the imaged two fractures. When frac hits are not visible on LF-DAS, microseismic reflection imaging can provide reliable monitoring of fracture propagation. The slight change in fracture azimuth cross Well 3 may be imaging artifacts due to the relatively narrow aperture even after stacking. Since only slow shear waves are used in this study, the imaging results are expected to be sensitive to fluid-filled fractures or faults. Strong far-field reflectivity zones are inferred to be related to fluid-filled faults and the reflection visibility may reveal the fluid propagation range. It is important to note that the actual fractures may be longer than the imaged reflectors since the visibility of reflections requires a sufficient impedance contrast.

Figure 5 displays vertical slices through the image volume along Well 3 and Well 5. About 300 m height of vertical fracture growth is well imaged, aligning with the frac hits or the position of stimulation stages. Fractures beyond the fracturing zone are still imageable but clipped to optimize interpretation. Reflection imaging can help to measure fracture height even when vertical fibers are not available. Strong energy with a larger width in Figure 5b may reveal fracture connecting with nearby faults, which is consistent with the side view of microseismic clouds in Figure 1b. The relatively weak reflectors around fiber 3 in Figure 5a are due to the muting of near-fiber reflections. In this case study, the majority of microseismic sources are located within the stimulation volume and close to the monitoring fiber, resulting in a very small time delay between the direct and reflected waves. As a result, it becomes difficult to separate the direct and reflected wavefield, posing a challenge in imaging reflectors within 40 m of the fiber.

With high-quality fracture images, the amplitude of DAS microseismic reflections can be used to measure changes in fracture properties, fluid volumes, and proppant geometry (Resheftikov et al., 2023). Advanced wavefield separation methods for DAS data, are required to obtain reflected waves with true amplitude for imaging. Automated detection of reflections would also accelerate the imaging process for real-time fracture imaging.

Conclusions

We developed a fracture imaging workflow by applying prestack Kirchhoff migration to DAS-recorded microseismic data. This framework enables successful 3D imaging of hydraulic fractures without being limited by any predefined assumptions about fracture geometry. Imaging results by stacking multiple events depict a comprehensive hydraulic fracture network with high resolution, which allows direct estimation of fracture length and height. By integrating the reflection imaging volume with microseismic clouds and LF-DAS, we can effectively monitor fracture geometry and propagation. Moreover, the analysis of reflected S-waves from nearby large-scale fault zones reveals fluid propagation and potential fracture connectivity. This framework facilitates time-lapse imaging of fracture growth and has the potential to estimate the statistical properties of fractures in the case of hydraulic fracturing or geothermal reservoir development.

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