How can we use one fracture to locate another?

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Hydraulic fracturing is an important tool that helps extract fluids from the subsurface. It is critical in applications ranging from enhanced oil recovery to geothermal energy production. As the goal of fracturing is to increase flow rates within the reservoir volume, and because the reservoir is typically heterogeneous, several fractures are often created. Because of confining stresses, most fractures that have been created and remain open are nearly vertical (Zoback et al., 2003). Creating a set of almost parallel fractures is quite common in situations with smoothly varying stress (Figure 1).

Cracking rock in the process of fracture creation generates microseismic events. The locations of these events correlate well with the fracture position. Although some spurious event locations are a result of errors in picking or come from sources elsewhere in the reservoir, it is safe to assume that most come from the area surrounding the fracture. Locating microseismic events recorded during the hydraulic fracturing of a reservoir is therefore an indirect method to image the corresponding fractures (Bennett et al., 2006).

In order to record microseismic events, a monitoring well is instrumented with three-component receivers. In practical situations, their total number typically varies in the approximate range of 8–16. Direct arrivals from each microseism are recorded and analyzed one-by-one for the purpose of locating the event. While various proprietary algorithms are employed in industry, many rely on picked traveltimes and an estimated polarization of the recorded wave. Those, along with a velocity model constructed using calibration shots, allow ray tracing of microseism source locations.

This approach results in perfect recovery of event locations if the data are noise-free and the velocity model is perfectly known. When velocity and measurement uncertainty are introduced, the locations are estimated with errors. Using multiple receivers allows some of that error to be reduced, although the improvement achieved by averaging over a small number of receivers is typically quite modest.

Interferometric microseism localization

Fractures are often created in proximity to one another. One of the fractures will be the closest to the monitoring well with, for example, others stepping away from it. The locations of the microseisms originating closer to the receivers are typically better known, because the angular coverage of a source with a fixed receiver array is best when the source location is nearby. The velocity obtained with the help of core samples and calibration shots also best represents the area in the immediate vicinity of the borehole containing the receivers.

It is natural to try to use this more reliable information about the nearest reference fracture to improve imaging of other fractures further away. For example, the distance between a second fracture and the reference fracture along with the known position of the latter helps constrain the location and the geometry of the former. We will use seismic interferometry to build constraints that reduce the uncertainty of microseism locations in a second fracture with reference to a nearer fracture, and improve our understanding of the fracture system as a whole.

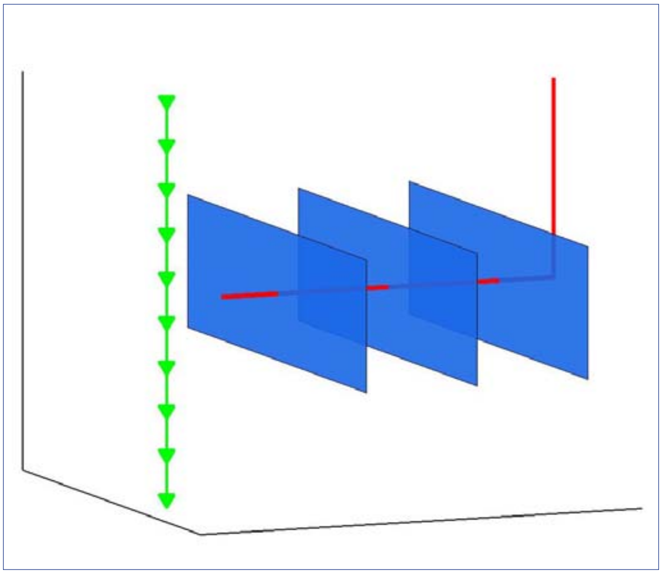

Figure 1. Water is injected under pressure through the treatment well (red) in order to create multiple fractures. The process is seismically monitored from the observation well (green).

Classical interferometry. Acoustic interferometry allows the reconstruction of the Green's function between two receiver locations if the medium is properly illuminated by physical sources. By acoustic reciprocity, we can also recover the Green's function between two source locations if the medium is surrounded by a sufficient number of receivers (Curtis et al., 2009); here we use this latter formulation.

Here we concern ourselves with only the kinematics associated with direct arrivals. Traveltimes of direct waves normally depend on local properties of the medium between the source locations. Velocity perturbations far away from that area have no effect on the traveltimes in nonpathological cases. This makes traveltimes particularly well suited to constrain the relative position of different microseismic events.

In order to find the Green's function between two sources in 3D, we ideally compute an integral of the cross-correlogram of the two common source gathers over a 2D aperture of receivers (Schuster and Zhou, 2006). The Green's function then comes from the stationary contribution to this integral (Snieder, 2004), where the partial derivatives with respect to each 2D coordinate of the source array are zero (Figure 2). With only a 1D aperture of receivers, it is impossible to re-

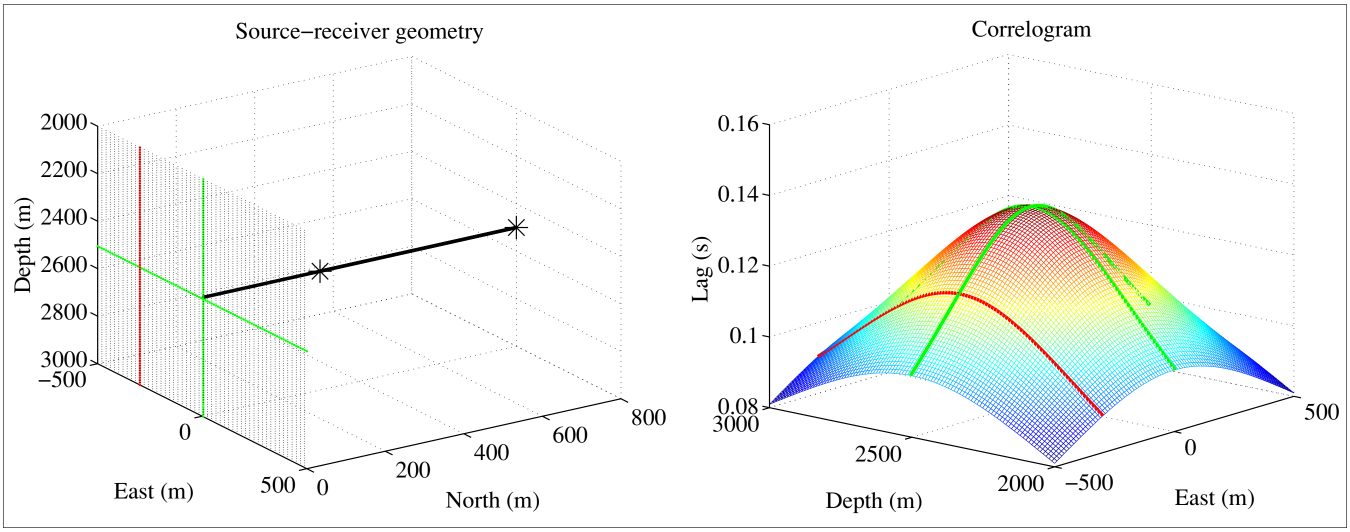

Figure 2. (left) The ray that connects two sources is received at the stationary location (intersection of two green lines) of the 2D receiver aperture. (right) The stationary receiver location is the stationary point of the 2D cross-correlogram of the two common source gathers. The cross-correlogram (red curve on left) calculated over a one-dimensional receiver array (red line on right) may exhibit an extremum, but it need not correspond to any physical ray or yield a physical traveltime.

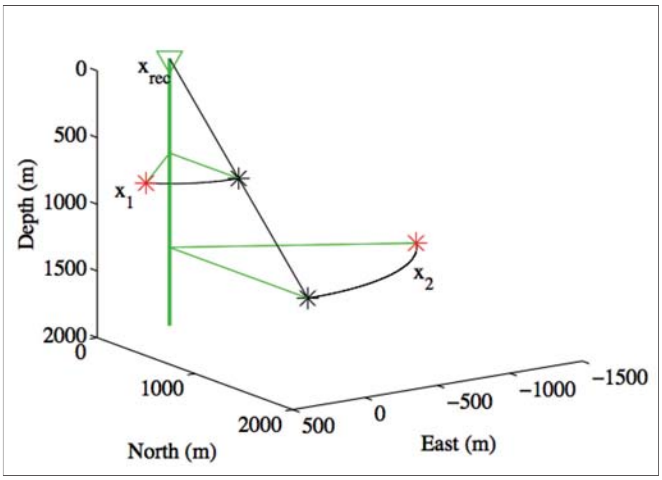

Figure 3. The receiver in a 1D array is (vertically) stationary with respect to two given sources (red stars) if the source locations can be rotated about the receiver line into collinear positions (black stars).

cover the full Green's function, but we show in the next section that we can recover partial information about the Green's function including the elevation and the radial traveltime between the two source locations.

Single-well imaging. When classical interferometry is employed, stationary contributions add constructively and nonstationary contributions are stacked out automatically. However, sufficient information must be present in the data to allow this to occur. Because our interest is ultimately in the stationary contribution, and because the stationary phase point is defined as one where two partial derivatives are zero, using a two-dimensional receiver array is critical for the final success of this process. Because only one partial derivative can be estimated with a 1D receiver aperture, stationary phase points are ill-defined and physical traveltimes cannot be reliably estimated. However, a cross-correlogram constructed using data recorded by a 1D receiver array still contains partial information about wave propagation between the two source locations; we exploit this property to improve microseism location in fractures adjacent to a known fracture.

Although our method is fully applicable to any known velocity model through which rays can be traced, here we consider for simplicity a homogeneous model. Assume that the receiver array in the monitoring well is strictly vertical. This assumption is also not critical for success of the method, but it will simplify the presentation. Because the receiver array is one-dimensional, so are the events in the cross-correlogram. Event moveouts are given by correlation lags as a function of the receiver depth.

The physical ray connecting any two microseism sources will almost never intersect the one-dimensional receiver array. But the cross-correlogram event consisting of the cross-correlation of the direct arrivals from the two sources will still have a (one-dimensional) stationary phase point provided that the sources can be rotated about the receiver array axis so that the two sources and some receiver from the array lie on the same ray (Figure 3). If the stationary phase point lies between two receivers, the correlation lag may be interpolated.

The true source locations and their apparent images obtained by rotations into the same vertical plane are indistinguishable based on the recorded data because the vertical array is kinematically insensitive to the azimuthal information. The stationary depth of the cross-correlogram event marks the stationary receiver, which records the ray connecting those rotated sources. The stationary lag represents the physical traveltime between the two rotated sources, and it is typically different from the physical traveltime between the original sources because of the rotational ambiguity.

We represent all source locations, initial and rotated, in spherical coordinates centered at the stationary receiver. Then we can rephrase the 1D stationary phase condition stated

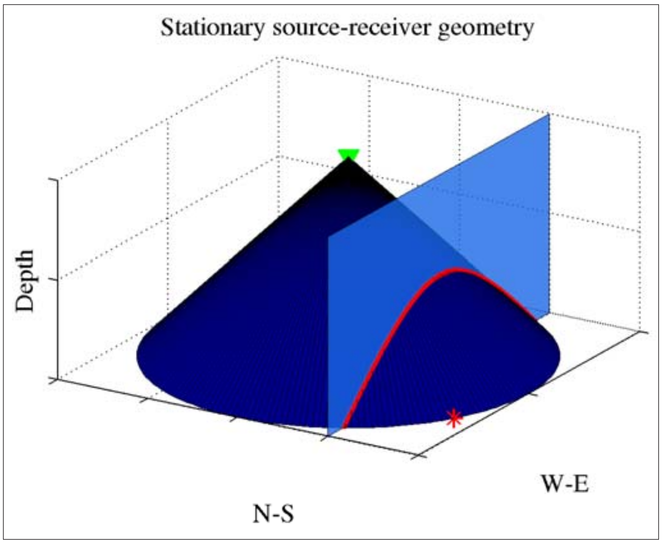

Figure 4. The unknown elevation and the radial distance of a source (red star) can be estimated with the help of many stationary sources in the neighboring fracture (vertical plane). The elevation of any source along the red curve is the same as the one we seek to estimate. Their radial distances can also be used to estimate the radial distance to the unknown source location.

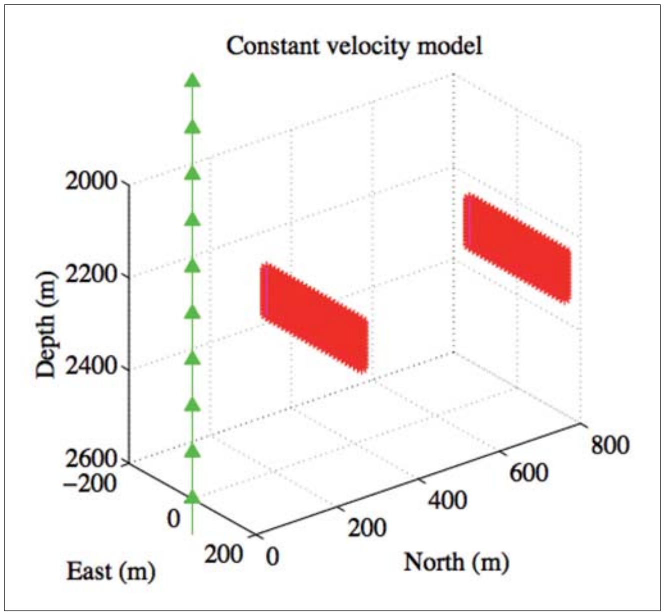

Figure 5. The numerical setup with a monitoring well and two vertical fractures nearby. A source from the fracture further away is localized using the nearest fracture.

above as follows. The moveout of the cross-correlogram of direct arrivals from two sources has a stationary point at some receiver depth if they have identical elevation angles when viewed from that receiver. The constant elevation-angle surface is a cone with the apex at the receiver location (Figure 4). Any two sources that lie on this cone will produce a cross-correlogram event with a stationary phase point corresponding to the same receiver depth.

We see that while cross-correlograms cannot be used to distinguish sources with different azimuths, they do provide meaningful constraints on elevation angle and radial distance. If the medium is not homogeneous, then the cone is replaced with a more general surface obtained by ray tracing the medium from a fixed receiver point at a constant elevation angle in all azimuthal directions. As before, the stationary relationship between a known source location and an unknown source location permits the recovery of two out of the three unknown spatial parameters.

Suppose we know one source location in the reference fracture, including its elevation angle and the radial distance with respect to some receiver. Then we also know the elevation and the radial traveltime (not the physical traveltime) from the first source to any other source in another fracture so long as the two sources form a stationary pair with the selected receiver being stationary. Because the total number of sources in the reference fracture is typically large, we can expect to have many redundant measurements of the elevation and radial distance of any source in the second fracture. Figure 4 shows a source in the second fracture and an entire curve of sources from the reference fracture. Any source located along that curve forms a stationary pair with the selected source in the second fracture and helps reduce the localization uncertainty. Unlike the classical method, where the averaging is performed over all receivers, in this method the averaging is over all source locations in the reference fracture. This results in a much smaller location uncertainty as we demonstrate in the next section.

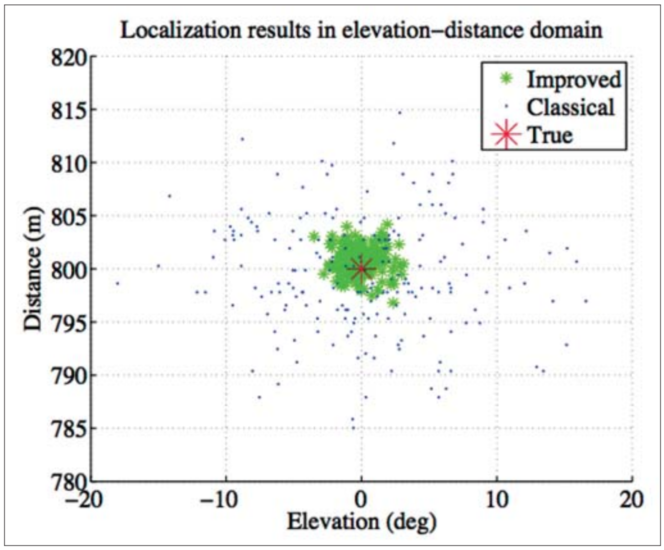

Figure 6. A comparison of localization results for the classical (blue) and interferometric (green) methods is plotted in the elevation-angle/radial-distance domain. A significant improvement is seen in both dimensions.

Numerical results

To demonstrate benefits of the interferometric imaging of sources using a reference fracture, we perform a numerical experiment. Two vertical planar fractures are positioned next to a monitoring well at a depth of 2300 m (Figure 5).

For illustration purposes, we will attempt to localize a single source in the second fracture using 625 sources positioned on a regular grid in the reference fracture. Localization of the event is performed using noisy data recorded by a single receiver. Two hundred realizations of noisy data are generated, and for each realization we obtain an estimate of the source location using both the classical and the interferometric imaging methods. A known homogeneous velocity model is assumed. The location results are plotted as elevation angle and radial distance (Figure 6). The classical localization method, used as a reference, reconstructs the location of the event based on estimated traveltime and polarization of the P-wave. The microseism source activation time is assumed to be known in this example, but in practice the radial distance is deduced from P- and S-wave arrival times. The amplitude maximum is interpreted as the time of the event, and the polarization is estimated based on the SVD analysis of the P arrival (de Franco and Musacchio, 2001).

The same microseism is then localized using the interferometric method. We observe that, by averaging information provided by multiple stationary sources in the reference fracture, the uncertainty in source localization is reduced in the second fracture by a factor of 5. The performance of both methods would be further improved roughly equally by averaging over all available receivers. The reduction in localization uncertainty yields a more reliable estimate of positions of microseisms, which in turn results in a better understanding of the fracture network.

Conclusions

Reconstructing the Green's function between two source locations in a three-dimensional medium using classical interferometry requires a two-dimensional receiver aperture. When data are recorded in a single well with a 1D receiver array, fundamental concepts in interferometry such as a stationary phase point are not well defined, making the standard approach to retrieving the Green's function impossible.

However, with a single-well interferometric imaging method, the elevation angle and radial distance to a microseism source are well constrained through the use of a multitude of sources in a nearer reference fracture. This method does not offer additional constraints on the azimuth. We have shown that elevation and radial distances are recovered with much smaller uncertainty with the proposed method than they are with a classical localization technique. TLE

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