Introduction

Oil and gas held in tight shale formations does not flow in to a well unless the formation is stimulated. The stimulation process involves injection of fluid and proppant at high pressure to overcome the rocks natural breaking strength. The process fractures the rock and the proppant rushes in to the fractures. The proppant remains in the rock and holds the fractures open to semi-permanently increase the permeability for the required flow of hydrocarbons to surface. This technique has revolutionized the energy business in North America and is slowly spreading globally.

Very small earthquakes are produced during this process that can be monitored with sensitive geophone equipment. Mapping these micro-earthquakes is critical to understanding well efficiency, optimizing field production and development and minimizing environmental risk.

Here we present a new method of locating earthquake hypocenters that does not require the user to identify and associate P and S seismic arrivals, eliminates the use of hodogram plots and allows reliable and accurate real time processing with a hands-off approach. The whole event location process is fully or semi-automated.

Method

The acquisition of the data is achieved in the same way as conventional downhole monitoring, that is, an array of three-component geophones is deployed in a nearby well in or near the zone to be stimulated. The seismic sensor array is clamped in for the duration of the operation and data is recorded in a wireline unit on the surface, Fig 1. The data are fed directly into the event detector and detected events are fed to the location software. Orientation shots are still required and can be from downhole sources or from the surface. This new method can be applied to newly acquired data or for re-processing of vintage datasets.

Figure 1. Microseismic Data Acquisition

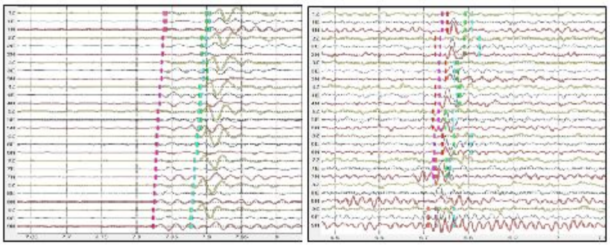

Figure 2. Actual and theoretical P and S time pick uncertainty, clean vs. noisy data

The traditional approach has been in use for decades and is proven in seismology for locating large single earthquake epicenters, Geiger, L. (1912). The method utilizes the discreet time pick samples of incoming compressional (P) and shear wave modes (S) that are identified in the full wavefield recorded data. An iterative search is applied to minimize the difference between predicted and observed P and S arrival times using a least-squares method and can be considered a variation to the Geiger method, Urbancic & Rutledge (2000). When this technique is applied to oilfield data with hundreds or thousands of micro-earthquakes it becomes problematic to efficiently associate the correct P and S wavemode couples that emanate from a single rupture. A meticulous and slow process can yield reasonable data but the results can still contain an unacceptable level of uncertainty (Hayles et al., 2011).

For example, in Figure 2, a clean event is seen and P wave and S wave time picks have been identified. The two picks for P (red and pink) and the two picks for S (green and turquoise) are the actual time picks compared to the theoretical time pick for the located data. With clean data the predicted and actual picks are very close. However, in the oilfield, we rarely get such clean passive seismic data.

Commonly, signal-to-noise ratio is very low and whilst events can still be identified in the data, P and S signals cannot be properly discerned and associated. This creates erratic polarisation readings and inconsistent locations.

By eliminating the requirement for time picks and using the wave mode approach we are able to isolate the P and S events, and maximize their amplitude using an automated rotation process.

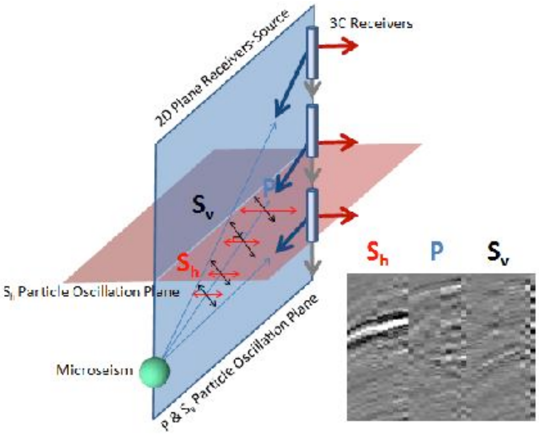

Figure 3. P & S mode energy recorded at downhole receivers is maximized on to a component to give azimuth and arrival angle. The full wavefield data is shown in the panel with the three wave modes successfully isolated on to separate components.

Figure 3 illustrates the mutually perpendicular nature of the particle oscillation of three wave modes - P, Sh and Sv - that are commonly observed from a microseismic earthquake. An arbitrary 3C receiver can be oriented such that each axis is aligned with one of the three wave-field modes. After this orientation, the P-axis will point to the microseism and the Sh-axis will be perpendicular to the vertical plane containing the microseism and receiver.

Migration is the process of focusing energy that has dispersed in space and time back to its correct spatial and temporal position. In hydro-fracture monitoring, we do not know when or where the microseism occurred - this is what we are trying to establish. However, we do know that the P and the S energy had the same origin in space and time.

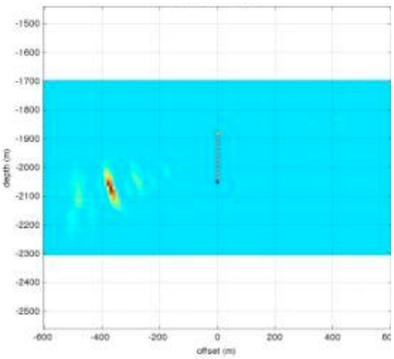

Fig 4. Migration of the a microseismic single source back to its point of origin through wave-mode separation, deconvolution and migration.

After isolating the P & S modes we reset the S wave times relative to the P times (i.e. establish a P to S time delay) by applying a unique weighted deconvolution operator as proposed by Haldorsen et al. (2009). When applied to each possible location in 3D space, we would expect the correct location in space to give an absolute maximum amplitude at the time zero location of the deconvolved wavelet. Searching for the amplitude maximum at each possible location is, of course, very computationally intensive. For a faster processing, the migration can be applied as a 2D process constrained to the vertical plane containing the P and Sv wave-field modes (Figure 3). The processing speed is further improved by pre-calculating arrival times and angles by ray tracing in a P/S velocity model.

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Figure 4 shows the location of a microseismic rupture along the 2D plane that was azimuthally constrained using incoming P or S energy. The maximum amplitudes are the location of the event with error uncertainty distributed about the image of the deconvolved wavelet as the amplitude decays away from the maximum. Event location has been successfully imaged by using the full wavefield and eliminating the requirement for onset time picking.

Examples

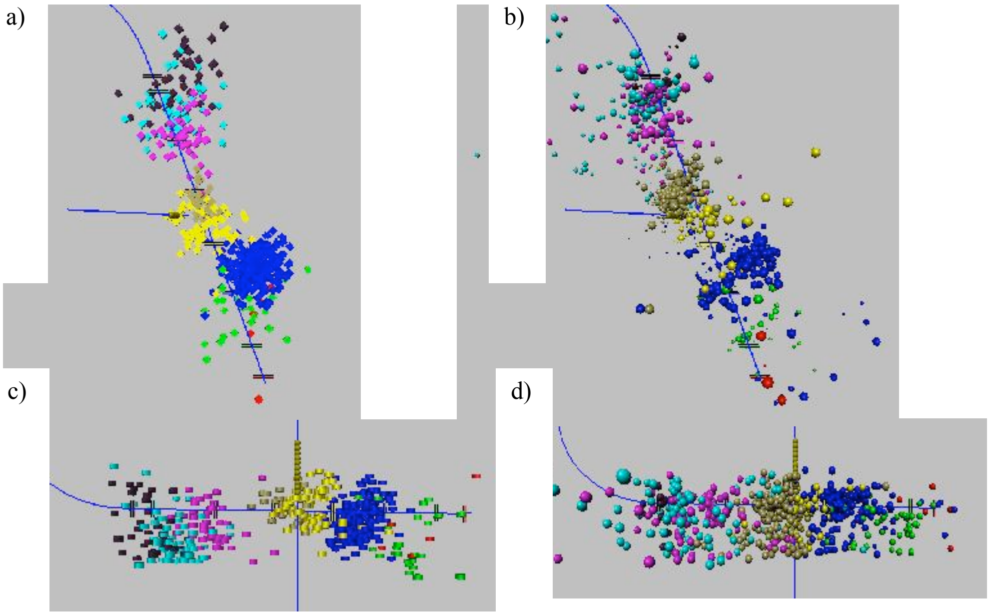

Fig 5. a) Traditional time-pick based processing (top down) b) New full-waveform processing (top down) c) Traditional time-pick based processing (depth) d) New full-waveform processing (depth).
The traditional method shows clustering of events and less distinct frac stages and frac characteristics. The new method described here eliminates the need for time picks and yields clearer stage by stage results and fracture network geometry.

As demonstrated in Fig 5, this opens the door to a data-driven way to process data that will enable more confident decisions to be made on stimulation efficiency. The fracture characteristics can be defined with more confidence and in real-time, i.e. during the operation. The imaged data shown above, Fig 5 b & d, is clipped at maximum amplitudes to be displayed in the conventional manner in a microseismic 3D data viewer, coloured by stage and scaled by magnitude.

Conclusions

We have introduced a new method of handling microseismic data for accurate and consistent hypocenter locations in real-time with an understandable hands off approach. The new method is well suited to real time data processing as it has removed the need for manual picks and tricky association of P and S wave-modes. We have compared the traditional approach to the new method and show that the wave-mode approach yields accurate results that can be delivered in a timelier manner. The method can be applied to temporary or permanent oilfield seismic sensor deployment.

Acknowledgements

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