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Velocity model optimization for surface microseismic monitoring *via* amplitude stacking

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ABSTRACT

A usable velocity model in microseismic projects plays a crucial role in achieving statistically reliable microseismic event locations. Existing methods for velocity model optimization rely mainly on picking arrival times at individual receivers. However, for microseismic monitoring with surface stations, seismograms of perforation shots have such low signal-to-noise ratios (S/N) that they do not yield sufficiently reliable picks. In this study, we develop a framework for constructing a 1-D flat-layered *a priori* velocity model using a non-linear optimization technique based on amplitude stacking. The energy focusing of the perforation shot is improved thanks to very fast simulated annealing (VFSA), and the accuracies of shot relocations are used to evaluate whether the resultant velocity model can be used for microseismic event location. Our method also includes a conventional migration-based location technique that utilizes successive grid subdivisions to improve computational efficiency and source location accuracy. Because unreasonable *a priori* velocity model information and interference due to additive noise are the major contributors to inaccuracies in perforation shot locations, we use velocity model optimization as a compensation scheme. Using synthetic tests, we show that accurate locations of perforation shots can be recovered to within 2 m, even with pre-stack S/N ratios as low as 0.1 at individual receivers. By applying the technique to a coal-bed gas reservoir in Western China, we demonstrate that perforation shot location can be recovered to within the tolerance of the well tip location.

1. Introduction

Hydraulic fracture of low-permeability reservoirs has become a popular technique for resource extraction in recent decades. Changes in fracture pressure, which are related to hydraulic fracture stimulation, cause a series of microseismic events in the reservoirs around the perforation shot (Warpinski et al., 2005). We can evaluate the fracturing effects (Eisner et al., 2010; Maxwell et al., 2010; Maxwell and Urbancic, 2002; Phillips et al., 2002) and determine the fracture propagation trend and source mechanism (Anikiev et al., 2014; Trifu et al., 2000; Zhebel and Eisner, 2015) using microseismic location and monitoring technology. However, efficient resource extraction requires accurate reservoir characterization, a key component of which is accurate locations of microseismic events. If the expected position of a perforation shot can be precisely located, then we can greatly enhance the reliability of the locations of nearby microseismic events. A key element in achieving this goal is to optimize the velocity model within the work area (Usher et al., 2013). Seismic tomography is a well-known technique for estimation of velocity structure by mathematical inversion. However, in the context of microseismic monitoring, it is not realistic to expect an accurate tomographic model of the velocity medium in the work area, due to both poor coverage of monitoring networks and limited number of passive sources (Bardainne and Gaucher, 2010).

To cope with these limitations, most existing velocity model optimization methods build a simple velocity model with a few parameters. Because a perforation shot position is generally very well known, it can be relocated iteratively to reduce the location error. However, existing iterative techniques mainly rely on picking of P and S wave arrival times (Bardainne and Gaucher, 2010; Pei et al., 2008, 2009; Tan et al., 2013; Jiang et al., 2016), meaning that seismograms with high signal-to-noise ratios (S/N) are required. This approach is suitable for borehole monitoring arrays; however, for microseismic monitoring at the surface, the seismograms of perforation shots tend to have low S/N ratios, and existing velocity model optimization methods do not perform well. In addition, it is often the case that part of the well-logging data is lost, which may affect the accuracy of *a priori* estimates of the initial velocity model.

In recent years, migration-based amplitude stacking techniques for microseismic monitoring from the surface have been gradually developed (Anikiev et al., 2007, 2014, Lu and Zeng, 2012, Zhebel and Eisner, 2015, Chambers et al., 2014). These techniques do not require first arrival picks at individual receivers, and can resolve velocity models using data with much lower S/N values than those of borehole arrays. Simulated annealing is a type of nonlinear Monte Carlo technique that is suitable for

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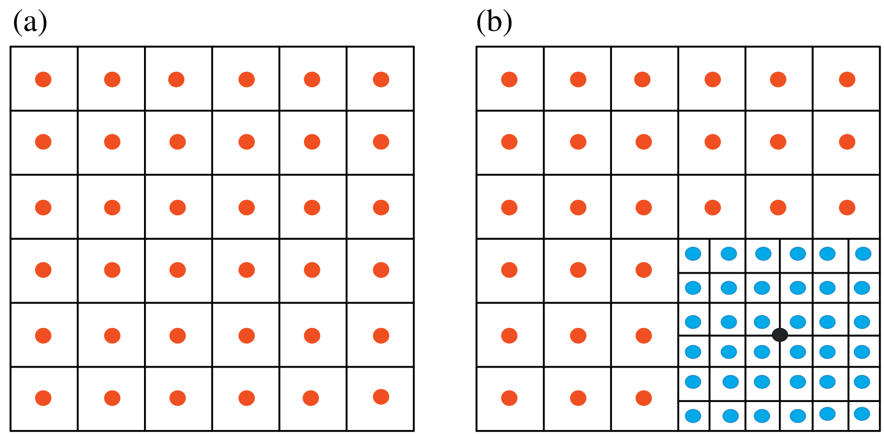

Fig. 1. Source location method using successive grid subdivisions: (a) first subdivision; (b) second subdivision.

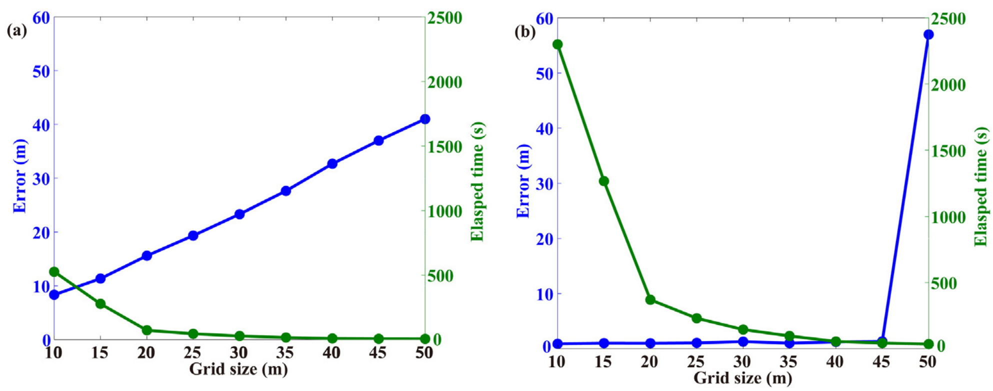

Fig. 2. Sketch of the original and improved algorithms. *X-axis* represents grid size. (a) Location accuracy and execution time of the original algorithm. (b) Location accuracy and execution time of the improved algorithm.

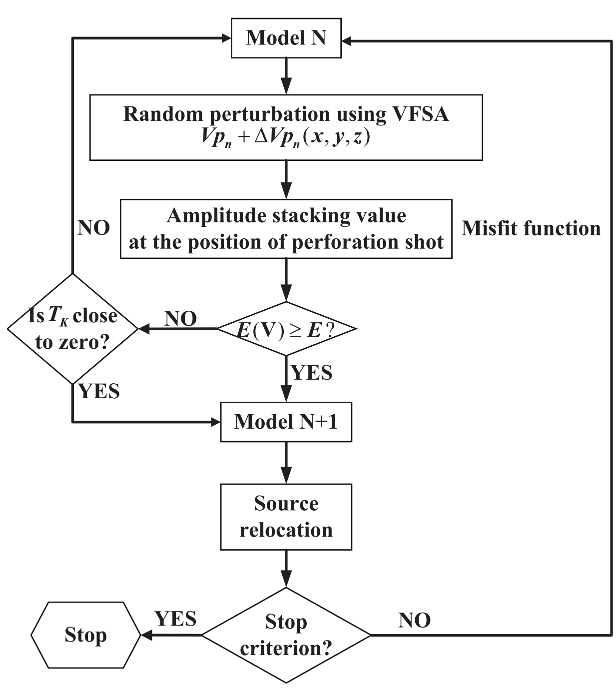

Fig. 3. Work flow diagram of velocity model optimization algorithm.

finding a global optimal solution in an objective function. Compared with local optimization algorithms, it depends less strongly on the initial velocity model (Pei et al., 2009). The disadvantage of this method is its low computational efficiency because of the slow iterative decrease in model temperature. Ingber (1989) presented a more rapid simulated annealing algorithm (VFSA) by iteratively calculating the annealing exponent. Computation was much faster than the conventional SA algorithm or the standard genetic algorithm (Ingber and Rosen, 1992).

When using velocity model calibration to compensate for source location inaccuracy, two main sources of error must be considered. The first is the contribution of additive noise. Although a low S/N ratio can be overcome by stacking, this will still have some impact on the waveform within the time window, which may introduce location inaccuracies after stacking. The second source of error is location inaccuracies caused by unreasonable prior information, including inaccuracies or missing data in well logs. As the measurement is near the wellbore, no lateral velocity variations are considered. If a reservoir has produced for a long time, seismic wave velocities might be altered as a result of depressurization and pore fluid pressure changes (Grechka et al., 2011; Pei et al., 2009; Quirein et al., 2006; Zhang et al., 2013). There are also other sources of inaccuracies that should be considered, including the positions of the seismic receivers and that of the perforation shot itself; these can affect processing results (Bulant et al., 2007), but both can be considered the second type of location inaccuracies. The influence of picking errors and errors in the origin time of the perforation shot can be overcome by stacking.

In this paper, we first introduce a new method for building a 1d velocity model from sonic log data, then introduce a new migration-based