Towards full-waveform inversion: A torturous path

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ABSTRACT

Full waveform inversion (FWI) can be viewed as an iterative cycle involving forward modelling, pre-stack migration, impedance inversion and velocity model updating. At each stage of the process there are many factors affecting the outcome. Among the most important are the type of modelling (acoustic versus elastic), derivation of the initial velocity model, the inherent differences between field data and numerically modelled data, and the conditioning of the field seismic data to be inverted.

Our attempts to derive an initial velocity model suggest that the integration of a refraction tomography velocity model with well log data provides a better initial velocity model than well log data alone as the sub-weathering velocities need to be included to help make a match between the first breaks of the field and modelled data. Initial comparisons of field and modelled shot gathers confirms that conditioning of the field seismic data plays a large role in the successful matching of field and modelled data.

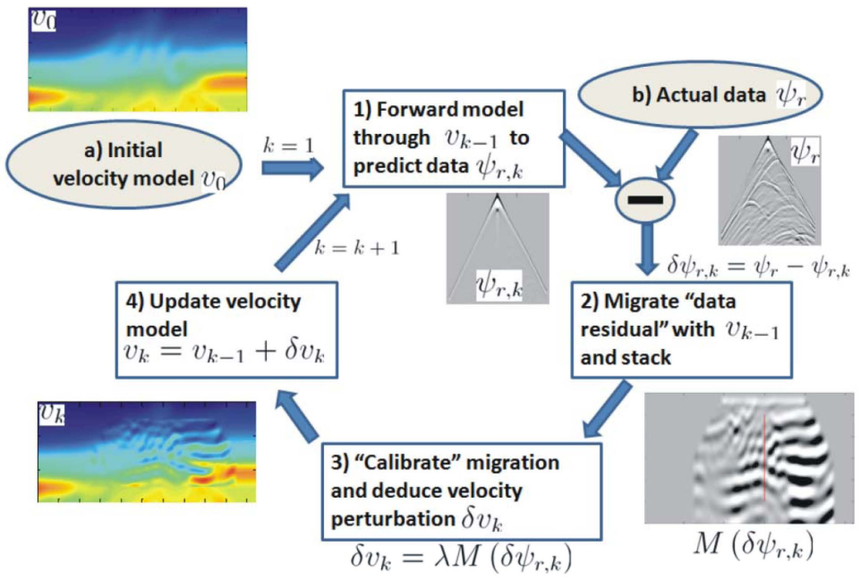

Fig. 1. The cycle of acoustic FWI. Data input are a) the initial velocity model and b) the real seismic data. Counter k increments from 1 to N when some defined stopping criterion is met. The velocity model v_{k-1} is used to predict synthetic seismic data with the same acquisition geometry as the real data. The data residual (real data - synthetic) is then pre-stack migrated and stacked. The pre-stack migration is used to estimate a velocity perturbation δv_k, which is added to the velocity model to estimate v_k.

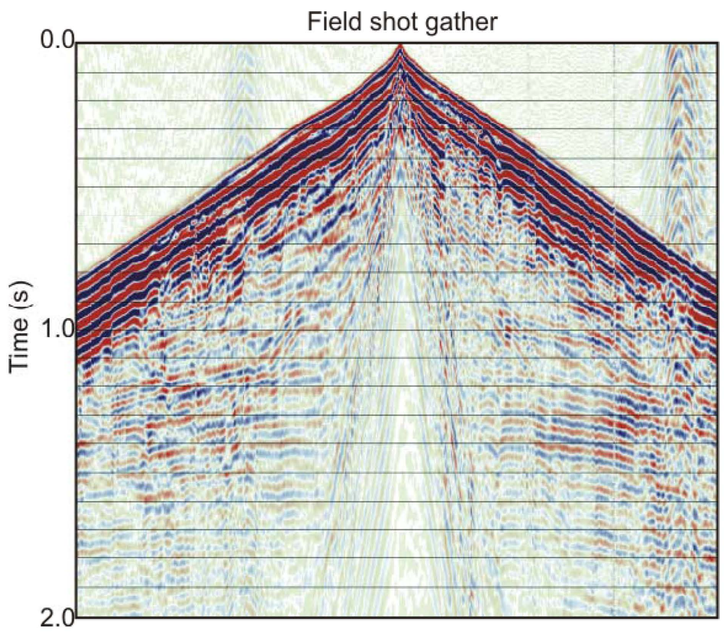

Fig. 2. The field shot gather used to determine the initial velocity model through matching first breaks.

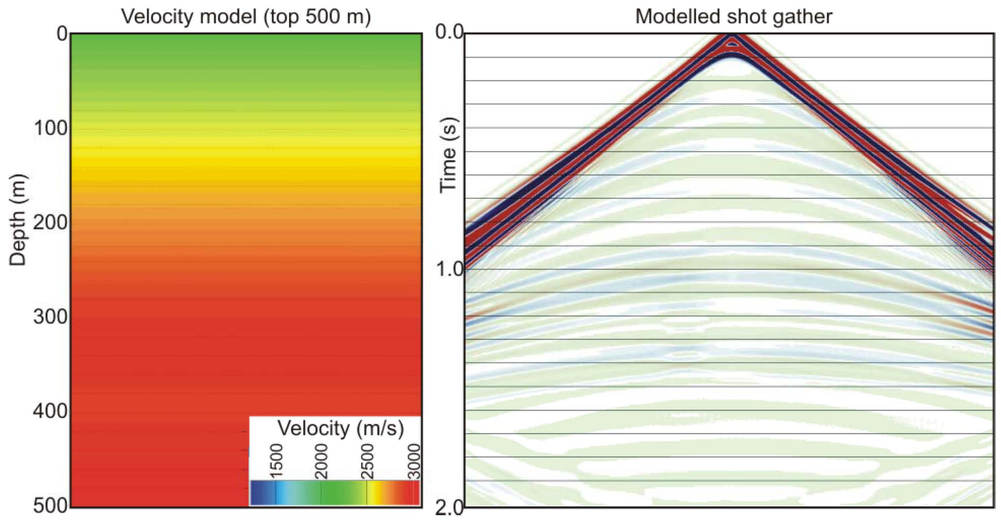

Fig. 3. The first velocity model we used. It is a smoothed version of the sonic data from the wells 12-27-025-21W4M and 09-27-028-22W4M with a linear projection of the velocity to fill the missing top 216 m to the seismic datum. The first breaks of the modelled shot gather do not match those of the field shot gather in Figure 2, having an average absolute difference of 21 ms.

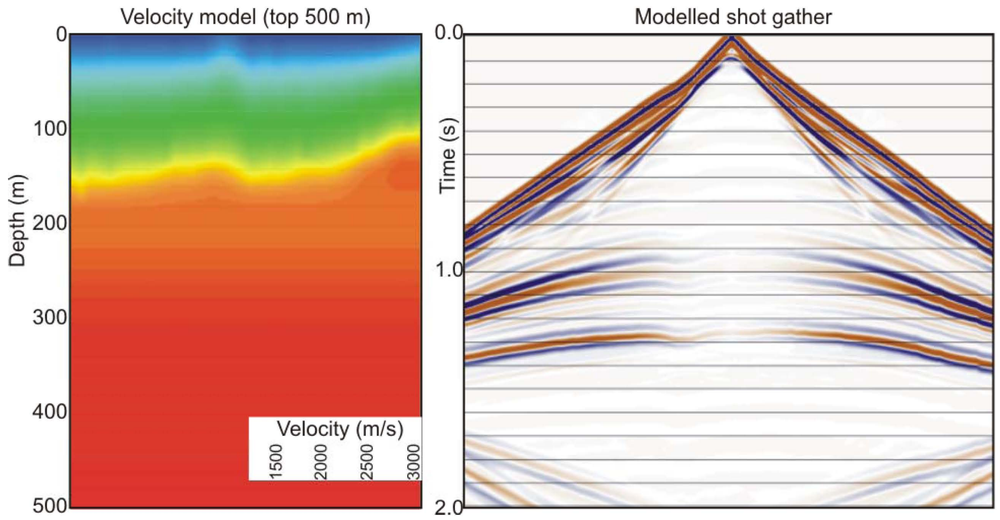

Fig. 4. The revised velocity model. It is the velocity model of Figure 2 with the tomography refraction velocity model integrated. The first breaks of the modelled shot gather match better those of the field shot gather in Figure 2, having an average absolute difference of 8ms.

We thought it interesting to compare the field and modelled data after bandpass filtering, since FWI starts with the lowest frequencies. We selected field data that had refraction statics and radial filters applied to remove groundroll. The field and modelled data were bandpass filtered to retain only frequencies of 2-5 Hz (Figure 5).

Application of spiking deconvolution to the radial-filtered shot gather does not make a noticeable difference. The gathers in Figure 5 are quite different and we would not want to start ascribing the difference between them to errors in the velocity model. Clearly, we must address the issues of processing the field data.

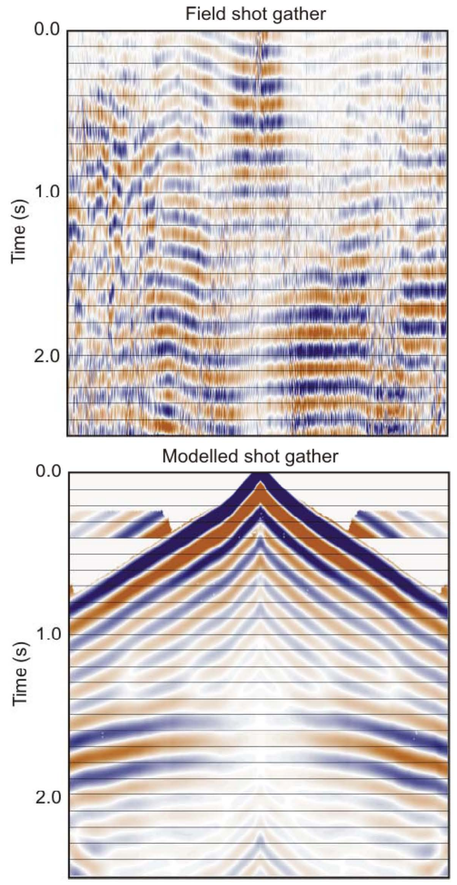

Fig. 5. Field and modelled shot gathers bandpass filtered to 2-5 Hz. The field gather has been processed to remove groundroll and other unwanted noise.

MODEL BUILDING

We have attempted to derive an initial velocity model for FWI of the Hussar data. We extracted one shot gather with unmuted first breaks (Figure 2) and will model shot gathers with the same topography. We started with the sonic log for well 12-27-025-21W4M, which runs from 208 m to 1565 m KB. We attached sonic data from well 09-27-028-22W4M to extend the depth to 2424 m. For the top 216 m to seismic datum we projected the well log velocity on a linear path. A smooth velocity curve was created from the composite well log and a synthetic shot gather generated by acoustic FD modelling (Figure 3).

We compared the first break picks of the model data to those of the field data, which had refraction statics applied that were derived through tomography. The average absolute difference between the modelled and actual picks is 21 ms so we modified the velocity model by inserting the near-surface model derived by CGGVeritas through traveltime tomography.

After a few iterations of smoothing and editing this model to amend the modelled first break picks, the average absolute difference between the modelled and actual picks is reduced to 8 ms. This velocity model and the synthetic gather generated with it are shown in Figure 4. At this time we have not addressed the issues of amplitude or phase differences between the field and modelled seismic data.

DISCUSSION

Practical implementation of FWI appears to be a difficult task. There are many factors to be taken into account. Amongst these are the question of acoustic versus elastic modelling, the modelling code, the determination of the initial velocity model, the inversion domain and the processing of the field seismic data.

Little of the published literature discusses the processing of field data, apart from advice to mute first breaks and apply deconvolution. We know there are many factors that affect the field data that cannot be accounted for in the numerical modelling, even if elastic modelling is used. Our future work will include analysis of data with different processing to assess the suitability of the processing for data intended for input into FWI.

The initial velocity model should be close enough to the true solution so that the inversion converges to a solution. We integrated well log data with a near-surface velocity model derived through refraction tomography and achieved a fair match between the field and modelled first breaks.
CREWES has access to several FD modelling codes and would like to test them all with the same velocity model to assess their applicability to FWI. We hope to experiment with shot gathers having different processing techniques applied to determine the optimum processing to apply.

ACKNOWLEDGEMENTS

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