A strategy for cooperative inversion of reservoir data

Laurence R. Lines

ABSTRACT

This note outlines a strategy for the estimation of an earth model whose responses match geological, geophysical and reservoir production data – a process known as cooperative inversion. The note gives a few preliminary examples and describes the essential components of a system for reservoir characterization.

INTRODUCTION

In exploration geophysics, we have applied inversion methods that attempt to find earth models whose responses match geophysical data. Seismic inversion and imaging methods have seen widespread applications, following early research including the papers of Tarantola (1984), Lines and Treitel (1984), Pratt and Worthington (1990), and Schuster (1996). The reliability of inversion was described by Ulrych, et al. (2000). While inversion has been frequently used to estimate models that can describe seismic data sets, methods known as cooperative inversion or joint inversion can be used to simultaneously fit various types of data such as seismic, electrical, gravity and magnetics observations. Cooperative inversion has been described by Lines, et al. (1988), and Paasche and Tronicke (2007). Inversion techniques have been used to improve seismic processing methods such as migration (as shown by Kuehl and Sacchi, 2003).

Since reservoir characterization will involve the interdisciplinary integrated analysis of geology, geophysics and reservoir engineering data, cooperative inversion should be a natural procedure for improving reservoir development. Promising research in this area has recently been initiated by Gosselin et al. (2003).

The proposed project would extend cooperative inversion so that earth models would describe the reservoir production history. The intention is to test the feasibility of cooperative inversion on models, and then proceed to the complete analysis of oil field reservoirs by using geological, geophysical, and engineering data.

METHODOLOGY AND RESULTS

Our research project objectives would be to test the proof-of-concept for using cooperative inversion to describe geological, geophysical, and reservoir engineering data, both in a model study and in a producing oil field.

These objectives would require that a number of aspects of the cooperative inversion problem be addressed. The following data sets and computer algorithms would need to be obtained:

1. Complete seismic wavefield modeling
2. Reservoir simulator algorithms

3. Time-lapse 3-D seismic data over a producing reservoir.
4. Reservoir production data over the same area.
5. A full set of well logs for the field, including dipole sonic logs.

Let us now examine the project's methodology in some detail. First, it is crucial to have general 3-D seismic modeling codes. It is our intention to start with finite-difference synthetic seismogram codes that can be readily interfaced with reservoir simulators. While our initial modeling will be made with available 3-D acoustic finite-difference codes, we intend to progress toward 3-D elastic anisotropic algorithms. There has recently been considerable promise in matching synthetic seismograms to real data, as shown in a case history from Lloydminster area, shown by Lines et al. (2005). The coupling of seismic analysis with reservoir simulation for the Lloydminster field was accomplished by Zou et al. (2006) with forward models. The next step should now involve a more automated procedure using cooperative inversion.

One of the main tools in petroleum reservoir characterization is 3-D time-lapse seismology (sometimes known as 4-D seismology). Since the processes of enhanced oil recovery will often affect the seismic velocities in the reservoir rock, the repetition of seismic surveys over time will indicate zones of reservoir change. A good example of time-lapse seismic monitoring in the cold production of heavy oil is shown in the following example from Lines et al. (2005). A close comparison shows that reservoir production has caused both amplitude changes (upper arrows) and traveltime delays (lower arrows).

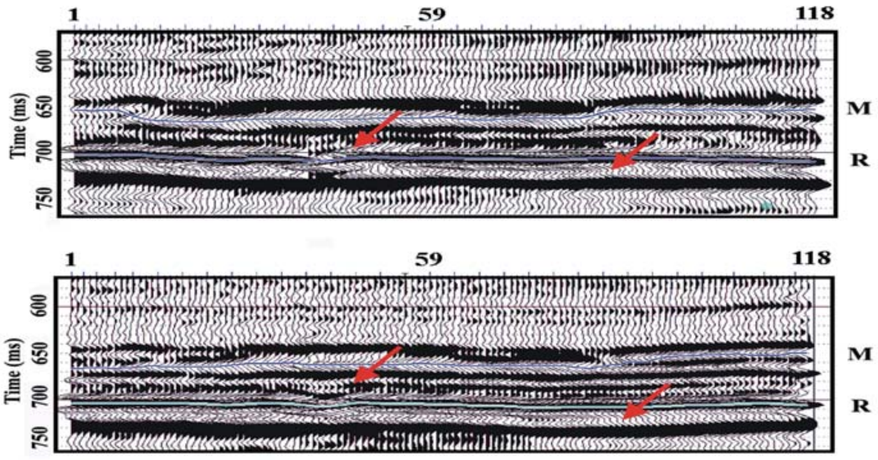

FIG. 1. Time-lapse seismic lines acquired in 1987 (top) and 1996 (bottom) over a cold production heavy oil field. When compared to the1987 survey, the 1996 survey shows a small but detectable delay of 2-10 ms in the traveltime between the McLaren reflection (denoted by M) and the Rex Sandstone reflection (denoted as R). The upper arrows indicate an amplitude difference between the seismic lines. The lower arrows indicate a picked horizon with a consistent time delay for the 1996 survey. Sections are 1180 m wide and show a time window of 200 ms.

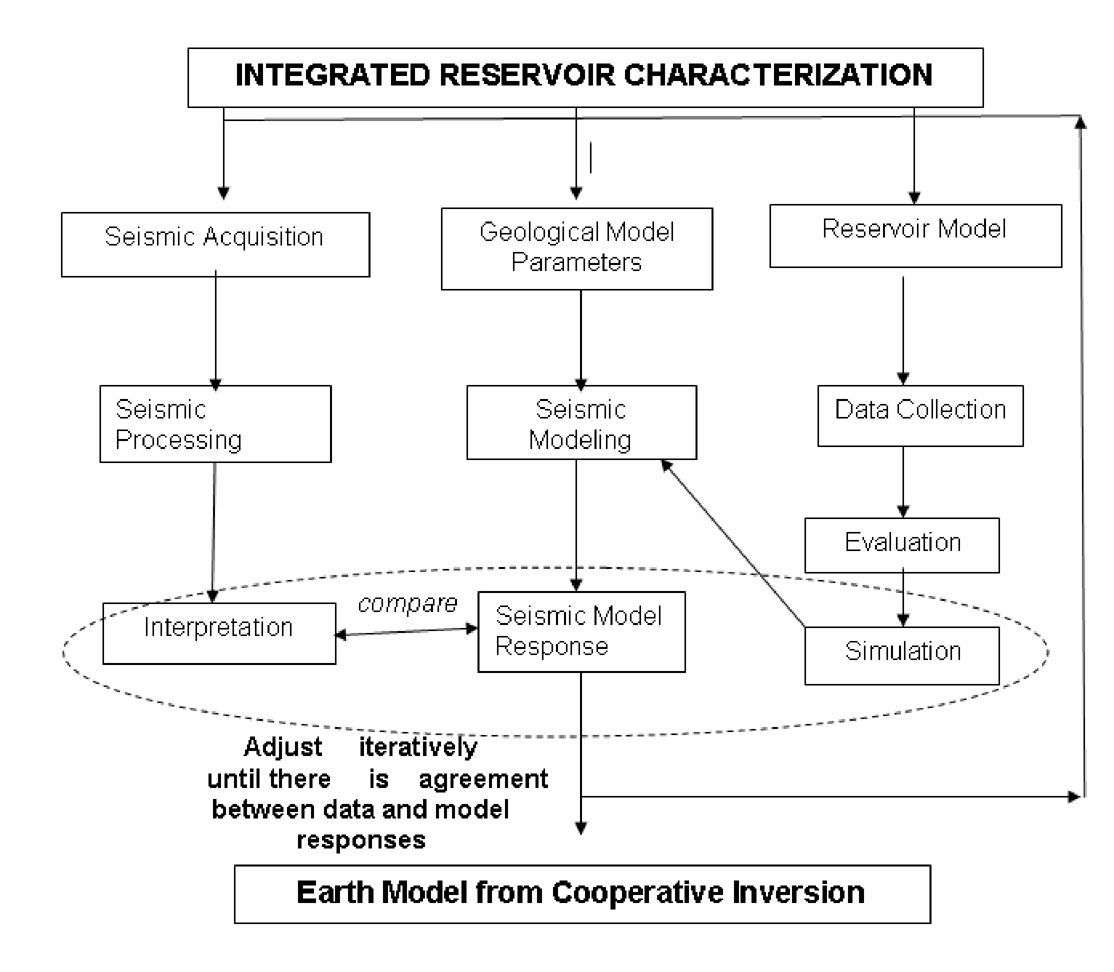

FIG. 2. Flow diagram outlining integrated reservoir characterization. When model responses match the data, an earth model from cooperative inversion is produced.

Following seismic analysis, we would need to use rock physics to relate the seismic properties to the properties of interest to reservoir engineers – namely properties such as porosity, permeability, pressure and fluid saturation. There are various reservoir simulator algorithms that are available to us. These are basically finite-difference partial differential equation solvers that simulate fluid flow while following conservation of mass and Darcy's law.

By relating seismic properties to the reservoir simulator model parameters, we can then transform seismic models into production history models and vice-versa. At this point, the goal of attempting to find an earth model, whose seismic velocity properties and reservoir model properties can be compared to all available data (seismic data, well logs, reservoir production history) is approached. Figure 2 describes a flow diagram defining the cooperative inversion method for reservoir characterization.

In Figure 2, there are three streams of analysis being carried out in this procedure. On the left side, there is acquisition, processing and interpretation of the seismic data. From this process, we obtain an earth model deduced from seismic data. The middle stream defines the procedure for seismic modeling. Initially we start with a first guess of model parameters, usually obtained from borehole information such as well logs and core measurements. These provide input for seismic modeling programs such as finite-difference wave equation modeling. The output of the modeling is a set of synthetic seismograms which we hope will eventually match the seismic data to within the noise levels in our data. On the right hand side, we see the development of a reservoir modeling simulation. After gathering production history data, we evaluate and create input for the reservoir simulation which will hopefully match our production history. Rock physics should allow us to convert reservoir properties to seismic velocities, or vice-versa. This allows an indirect comparison of the reservoir and seismic properties, and would cause us to alter our reservoir model, our seismic model or both. This is iteratively done until:

1. The seismic model matches the seismic data
2. The reservoir model matches the production history
3. The seismic and reservoir model are consistent.

This process can be done iteratively by forward modeling. In fact, Zou et al. (2006) give an example of this. Although this demonstrated feasibility, it did not automate the cooperative inversion for adjustment of model parameters. As illustrated in Figure 2, we use inversion/optimization methods and "adjust (the model parameters) iteratively until there is agreement between data and model responses". This is a data fitting exercise for both the reservoir and seismic modeling. Formally, this data fitting could be accomplished by least squares inversion of all data in the same way that we invert both seismic and potential field data. That is, we would minimize some error norm (objective function) measuring differences between data and model responses by adjusting model parameters. Such an objective function could be described mathematically by:

$J(m) = (\mathbf{d} - \mathbf{f}(m))^T(\mathbf{d} - \mathbf{f}(m)),$ where **d** represents the data, **f** represents the model response and *m* denotes the model parameters. In cooperative inversion we would chose to minimize an objective function that combines a weighted sum of the objective function of geoscience data, $Jg(m),$ and an objective function for the production data $Jp(m),$ or in other words we would minimize $J(m) = J_g(m) + \alpha J_p(m)$, where α is the weighting factor for the two data sets. Alternatively, we could sequentially minimize the two objective functions. Due to the nonlinearity of the problem, cooperative inversion will be done iteratively (and with some degree of interpretation). The end result would be an earth model whose response would be consistent with all available information.

CONCLUSIONS

The building blocks for cooperative inversion include geological, geophysical and reservoir characterization modeling, as well as optimization methods. Although these blocks are mostly in-place, each block is important and certainly non-trivial. While it is highly unlikely (or desirable) that cooperative inversion of reservoir data will ever become automated, the methodology could certainly be a valuable tool for enhanced oil recovery.

ACKNOWLEDGEMENTS

I thank the sponsors of this research including the Consortium for Research in Elastic Wave Exploration Seismology (CREWES), Consortium for Heavy Oil Research by University Scientists (CHORUS) and the Natural Science and Engineering Research Council of Canada (NSERC).

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