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Reservoir Simulation Model Updates via Automatic History Matching with Integration of Seismic Impedance Change and Production Data

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Abstract

Automatic history matching can be used to incorporate 4D seismic data into reservoir characterization by adjusting values of permeability and porosity to minimize the difference between the observed impedance change and the predicted impedance change, while remaining as close as possible to the initial geological model. To perform the history matching efficiently, an adjoint method is used to compute the gradient of the data mismatch and a quasi-Newton method is used to compute the search direction. Compared to other approaches that use the time-lapse seismic data to infer saturation and pressure directly, this method uses a finite-difference, black-oil reservoir simulator to ensure that the material balance and flow equations are honored. Two ancillary issues were important in obtaining a match. First, it was necessary to convert the map of change in reflection coefficients to a map of change in impedance. Second, it was necessary to characterize the noise in observed seismic impedance change data to prevent overmatching of the data. All the procedures are illustrated with an application to a reservoir in the Gulf of Mexico.

Introduction

The objective of automatic history matching is to obtain a reservoir simulation model that honors observed production history and is geologically plausible. Although dynamic data from the wells, such as pressure, gas oil ratio (GOR), and water oil ratio (WOR), provide useful information for reservoir characterization in traditional history matching, the resolution of an estimate obtained from this type of data is typically poor. The only way to improve the resolution in such cases is to integrate additional data that can provide more constraints, especially at the areas far from wells. Seismic data have much better spatial coverage than production data. We have chosen to history match the change in seismic impedance that is computed from the time-lapse seismic data. The change in seismic impedance is highly sensitive to changes in saturation and pressure in the reservoir; these changes can then be related to the porosity and permeability[1].

Automatic history matching problems are typically formulated as the minimization of the difference between actual and predicted data. Thus, the choice of an effective minimization algorithm is critical. In a recent comparison of several gradient-based minimization methods, Zhang and Reynolds[2] showed that the limited memory Broyden-Fletcher-Goldfarb-Shanno (LBFGS) method[3] is relatively efficient for large history matching problems. Thus, in this study, the LBFGS method is used for history matching of both production and seismic impedance change data.

Researches on the use of a reservoir simulator to history match both production data and time-lapse seismic data are fairly extensive. Landa and Horne[4] estimated reservoir parameters assuming that water saturation changes could be derived from the time-lapse seismic. They included dynamic data observed from wells. The reservoir model was re-parameterized to decrease the number of model parameters and the gradient simulator method was used to compute the gradient and the Hessian matrix. Huang et al.[5] used time-lapse seismic amplitude data and the finite perturbation method to calculate required derivatives. The method used by Waggoner[6] was similar. Huang et al.[7] used zonation to history match both production data and time-lapse seismic data. Each zone was assumed to have homogeneous properties. Because the number of model parameters was small, the finite perturbation method was used to compute the derivatives. Like Landa and Horne[4], Ditzhuijzen[8] matched water saturation changes presumably derived from multiple seismic surveys, as well as production data. The model parameters were geometric parameters of the faults, such as positions, size and throw because the authors believed that in that area, the geometric parameters were more important than the porosity and permeability for the reservoir