Joint Inversion of Reservoir Production Measurements and 3D Pre-Stack Seismic Data: Proof of Concept

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Summary

We develop a nonlinear iterative inversion algorithm for estimating three-dimensional (3D) reservoir parameters and initial fluid saturations jointly from pre-stack seismic data and fluid production history. The production measurements and the seismic data are synthetically generated from the output of a multi-phase fluid flow simulator. A Biot-Gassmann rock physics/flow substitution model is used to enforce a deterministic link between the multi-phase flow parameters and the elastic properties. Iterative nonlinear optimization is used to solve the least-squares minimization problem associated with the inversion. Fluid production measurements are sensitive to initial fluid saturations, fluid properties, porosity, and permeability. Pre-stack seismic data, on the other hand, provide good lateral and vertical control on lithology and fluid distributions. The proposed joint inversion approach, therefore, allows one to effectively integrate the best of the two measurement sets into a consistent 3D distribution of petrophysical variables and fluid saturations. Such distribution can be used for the accurate assessment of infill drilling and enhanced-oil-recovery operations. Synthetic test examples are presented with the sole objective to advance a proof of concept for the proposed joint inversion technique. The inversions require large computer resources and hence efficient numerical algorithms. We analyze the relative value of both sets of data and propose an extension of our algorithm to assimilate time-lapse 3D seismic data.

Introduction

Assessment and prediction of reservoir performance depends on the accurate specification of petrophysical parameters and initial fluid saturations. Simulation of multi-phase fluid-flow behavior is inherently a highly nonlinear problem. The corresponding inverse problem is not only mathematically and computationally challenging, but also highly unstable and non-unique. Therefore, additional independent information is required to stabilize the inverse problem and to reduce the space of solutions. Geostatistical simulation is often used to provide a set of a-priori models based on existing well-log data. In this context, 3D seismic data have been used to guide the geo-statistical interpolations through co-kriging and cosimulation techniques. While geostatistical simulation is an efficient interpolation technique, it is meant to honor quantitatively both the fluid production measurements and the 3D seismic data. Practice shows that the amplitude variations of seismic data can be either deterministically and/or non-deterministically (statistically) related to fluid saturation, pore pressure, and petrophysical properties. In this paper, we propose a quantitative procedure to incorporate 3D seismic data into the estimation of petrophysical parameters via reservoir history matching. We accomplish this through the use of rigorous nonlinear inverse theory. The inversion is computationally challenging and, with the sole objective of advancing a proof of concept, we present a comprehensive exercise based on the construction of a 3D synthetic reservoir model. We focus our attention the use of pre-stack seismic data as the latter exhibit sensitivity to a larger set of elastic parameters than post-stack seismic data. The inverse formulation advanced in this paper is also suitable for the quantitative interpretation of 4D seismic data.

Simulation and Inversion of Multi-Phase Fluid-Flow Measurements and Pre-Stack Seismic Data

Reservoir history matching is routinely used to provide a quantitative indication of the spatial distribution of petrophysical parameters in the reservoir. Accordingly, reservoir parameters such as absolute permeability and porosity are adjusted in order to minimize the misfit between the observed and the predicted time record of fluid production measurements. The predicted time record of fluid production measurements is generated from the numerical solution of a set of coupled partial differential equations that describe multi-phase flow phenomena in porous media. Extensive work in this field, however, has shown that a geological and petrophysically sound solution is difficult to obtain without prior information about the reservoir. History matching is a highly non-linear and non-unique problem that remains intractable without restricting it to satisfy specific a-priori assumptions. By making use of a Bayesian statistical rule, the objective function for the minimization can be written as (Wu et al., 1999)

\[
J_i = (d - d^{obs})^T C_D^{-1} (d - d^{obs}) + (m - m_0)^T C_M^{-1} (m - m_0) \, .
\]

where \( m = (k, \phi)^T \) is the vector of reservoir parameters, \( d \) is the fluid production data, \( C_D \) is the covariance of measured data, and \( C_M \) is the model covariance matrix.

The superscript obs is used to identify the time record of
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When the number of blocks used to discretize the reservoir is large, numerous combinations of parameters can equally satisfy the time record of fluid production measurements. Therefore, the second additive term in Eq. (1) is intended to stabilize the solution in the presence of noisy data and to bias the inversion toward a specific set of solutions in parameter space. In principle, seismic data could be used to bias the inversion toward a specific set of petrophysical reservoir models. There are many ways in which the seismic data could be incorporated into reservoir history matching. A way would be to use either post-stack or pre-stack gathers. Usage of full-wave inversion seems at present out of the question because of the excessively high computation times required by the forward simulations. To date, little has been reported on the use of pre-stack seismic gathers to aid in the construction of reservoir model. Pre-stack seismic data offers several degrees of flexibility as are capable of providing separate estimates of P-wave velocity, S-wave velocity, and bulk density. Inversion of pre-stack seismic data alone can be approached with the use of an objective function similar to that described by eq. (1), except that the vector of unknown parameters would contain values of P-wave velocity, and S-wave velocity, and bulk density. Inversion of pre-stack seismic data can be approached with the use of an objective function similar to that described by eq. (1), except that the vector of unknown parameters would contain values of P-wave velocity, and S-wave velocity, and bulk density. Inversion of pre-stack seismic data alone can be approached with the use of an objective function similar to that described by eq. (1), except that the vector of unknown parameters would contain values of P-wave velocity, and S-wave velocity, and bulk density. Inversion of pre-stack seismic data alone can be approached with the use of an objective function similar to that described by eq. (1), except that the vector of unknown parameters would contain values of P-wave velocity, and S-wave velocity, and bulk density. Inversion of pre-stack seismic data alone can be approached with the use of an objective function similar to that described by eq. (1), except that the vector of unknown parameters would contain values of P-wave velocity, and S-wave velocity, and bulk density.

The poro-elastic relationships summarized by eqs. (2) through (4) are subsequently used to minimize an objective function that includes both time production measurements and pre-stack seismic data.

Test Model

Figure 1 depicts the synthetic test model. It consists of a spatially heterogeneous, hydrocarbon-bearing sand embedded in an otherwise shale background. The size of this reservoir is 1704 x 1704 x 400 ft and consists of 11x11x5 uniform blocks in the x, y, and z directions, respectively. Fluid flow simulation was performed with a much finer finite-difference grid but block size and location were kept consistent for the generation of both seismic and fluid-flow production data. Seismic data were simulated as locally 1D pre-stack gathers, one per vertical column of reservoir blocks, with the complete set of gathers spatially covering the entire reservoir model. A single pre-stack gather was assumed to cover source-receiver angles of up to 45°. Each block exhibits specific values of porosity, permeability, and initial fluid saturation. The petrophysical parameters were entered into a Biot-Gassmann fluid substitution model and from these values elastic parameters were computed for each block. Prior to that step, petrophysical parameters for the blocks were obtained from the output of probability density functions and semi-varioigrams. Vertical permeability was assumed to be one tenth of the horizontal permeability. Relative permeability curves were assumed to be spatially homogenous and chosen to describe a water-wet system. As shown in Fig. 1, oil production was simulated with the use of a 5-spot well pattern for water flooding. The central well was used for water injection while the remaining wells were used for oil production. Producer and injector wells were further constrained to work at constant pressure.
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Fig. 1. Graphical description of the 3D synthetic reservoir model. The picture shows the distribution of oil saturation during water flooding.

Inversion of Petrophysical Parameters From Production Data

Fluid production data were simulated numerically for times between 650 and 1400 days after the onset of water injection. During the simulation time, water breakthrough occurred after 600 days. The inversion based solely on production data was initiated with uniform values of porosity, permeability, and initial water saturation for all of the blocks. In turn, these uniform values were obtained by performing an inversion in which all of the blocks were assumed to be homogeneous. The upper two panels in Fig. 2 compare the input and inverted distributions of porosity and permeability, respectively, across the 3rd horizontal layer of the test model. These distributions were obtained using the simulated data plus 5% zero-mean Gaussian noise. As can be observed in Fig. 2, the inverted distributions of porosity and permeability do not compare well with the original distributions. It appears as though the inverted distributions were highly influenced by the actual values of porosity and permeability in the vicinity of wells.

Inversion of Elastic Parameters From Seismic Data

Making use of Biot-Gassmann’s effective medium equations, petrophysical parameters were transformed into corresponding elastic parameters for each of the blocks in the model shown in Fig. 1. Subsequently, pre-stack seismic data were generated assuming a Ricker wavelet of central frequency equal to 25 Hz. Zero-mean, 5% Gaussian noise was added to the simulated pre-stack seismic data and the noisy data were inverted using an algorithm reported by Sen and Stoffa (1991). Results from this exercise are shown in Fig. 2, and consist of distributions of P-wave velocity, S-wave velocity, and bulk density. The same figure compares the pre-stack inversion results with the original distributions across the 3rd layer of the model. We observe a significant consistency of the inverted results with the original distributions of elastic parameters.

Joint Inversion of Production Measurements and Seismic Data

It becomes evident from the previous two inversion exercises that the joint inversion of pre-stack data and fluid production measurements could provide estimates of porosity and permeability devoid of near-borehole sensitivity. Although appealing from a practical viewpoint, such joint inversion is computationally challenging and CPU intensive. We describe the formulation of an efficient inversion procedure that can assimilate both pre-stack seismic data and fluid production measurements. Examples of inversion are obtained from noisy measurements that provide a significant improvement over the inversions obtained separately either from production measurements or seismic data.

Conclusions

Inversion of fluid production measurements can be highly unstable in the presence of moderate amounts of noise. In consequence, a large number of very diverse models exist that honor the measured production data. The inclusion of seismic data in the inversion provides a quantitative way to naturally bias the inversion toward a geologically consistent set of solutions in model space. Such an inversion strategy becomes appropriate when seismic amplitude data are statistically related to the underlying petrophysical parameters. In this paper we provided a simple 3D example that shows how the usage of pre-stack seismic data can significantly improve the inversion of petrophysical parameters obtained from production data alone. The same formulation could be easily adapted for the quantitative integration of 4D seismic data and fluid production measurements.

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References

Fig. 2. Input (left-hand side panels) vs. inverted (right-hand-side panels) spatial distributions of petrophysical and elastic parameters. The panels above are plan views taken across the 3rd layer of the synthetic reservoir model shown in Fig. 1.