

Joint flow–seismic inversion for characterizing fractured reservoirs: theoretical approach and numerical modeling

Peter K. Kang*, Yingcai Zheng, Xinding Fang, Rafal Wojcik, Dennis McLaughlin, Stephen Brown, Michael C. Fehler, Daniel R. Burns and Ruben Juanes, Massachusetts Institute of Technology

SUMMARY

Traditionally, seismic interpretation is performed without any account of the flow behavior. Here, we present a methodology to characterize fractured geologic media by integrating flow and seismic data. The key element of the proposed approach is the identification of the intimate relation between acoustic and flow responses of a fractured reservoir through the fracture compliance. By means of synthetic models, we show that: (1) owing to the strong (but highly uncertain) dependence of fracture permeability on fracture compliance, the modeled flow response in a fractured reservoir is highly sensitive to the geophysical interpretation; and (2) by incorporating flow data (well pressures and production curves) into the inversion workflow, we can simultaneously reduce the error in the seismic interpretation and improve predictions of the reservoir flow dynamics.

INTRODUCTION

Characterizing fractured geologic formations is essential in exploration geophysics and petroleum engineering, as much of the oil and gas reserves worldwide are from reservoirs that are naturally fractured. The relevance of fracture characterization has only increased in recent years with the growth of unconventional resources like oil and gas shale. Determining the effectiveness and sustainability of hydrocarbon production in those environments depends critically on our ability to characterize natural and induced fractures.

Traditionally, seismic interpretation and flow modeling have been performed independently. Reservoir modeling typically follows a unidirectional workflow. From an interpretation of seismic surveys and other geophysical and geological data, a structural reservoir model—with reservoir geometry and faults—is built. Facies data and inference are then used to populate reservoir properties (like porosity and permeability) on a fine grid known as a static model (or geomodel). The number of cells in the geomodel is typically too large to perform reservoir flow studies, so a dynamic model is built from either upscaling procedures or multiscale techniques, which solves the reservoir flow equations on a coarser grid. The rock physics properties (like porosity and permeability) and reservoir dynamics properties (like relative permeability and capillary pressure) are then modified to history-match production data. By then, all feedback to the originating seismic data, and often all geologic realism, is lost.

In parallel, seismic interpretation in challenging geologic environments like naturally-fractured reservoirs is plagued with uncertainty. The goal of our work is twofold: on one hand, reduce that uncertainty by incorporating dynamic flow measure-

ments into the seismic interpretation; on the other, improve the predictability of reservoir models by making joint use of seismic and flow data.

The basic tenet of our proposed framework is that there is a strong dependence between fracture permeability (which drives the flow response) and fracture compliance (which drives the seismic response). This connection has long been recognized (Pyrak-Nolte and Morris, 2000; Brown and Fang, 2012), and recent works have pointed to the potential of exploiting that connection (Vlastos et al., 2006; Zhang et al., 2009). Here, we propose a formal approach to improved characterization of fractured reservoirs, and improved reservoir flow predictions, by making joint use of the seismic and flow response.

OVERALL FRAMEWORK

Our approach seeks to combine seismic scattered wavefield data that provides spatial estimates of fracture orientation, spacing, and compliance (Fang et al., 2013; Zheng et al., 2013) (Fang et al, 2013; Zheng et al., 2013) with flow data (pressure and saturation values) at a number of well locations. The fracture compliance values obtained from seismic data analysis are related to permeability through a rock physics model (Pyrak-Nolte and Morris, 2000; Brown and Fang, 2012). Both the seismic data and the rock physics model contain potentially significant uncertainty. By combining the flow and seismic data in a single inversion we hope to obtain an optimal subsurface permeability field that can be used to predict reservoir flow.

The general workflow is shown in Figure 1. Our proposed framework is rather general and can be applied to field data, but here we restrict our exposition and validation to synthetic computer models. The starting point for the synthetic models is a ‘true’ compliance field, which entails generating: (1) a fracture network, which can be disordered but have certain geometric statistics (fracture density, length and orientation); (2) elastic compliance of the individual fractures, which also exhibits a predefined geospatial distribution (mean, variance, and correlation length). This model of interconnected discrete fractures, embedded in a reservoir matrix located at depth, is the common physical model from which seismic and flow response is determined (Figure 2a).

The true compliance field (C_T) and true permeability field (K_T) are related via a predefined rock-physics model, $K_T = f(C_T, \alpha)$, where α denotes a set of parameters governing the functional relation between C_T and K_T (Figure 2b). The objective is then to infer the true compliance field and compliance–permeability relationship by a procedure that unifies seismic and flow modeling.

Kang et al.: Joint flow–seismic inversion

Seismic modeling. We first run a forward seismic model on the true compliance field (C_T) to generate the detailed wavefield. We then treat this wavefield blindly, without knowledge of the underlying structure, to estimate the seismic compliance (C_M) by means of the double-beam method (Zheng et al., 2013) (Figure 3b). The error in the estimated compliance field, $e_c = C_T - C_M$, often exhibits a strong spatial correlation with the actual compliance field C_T (Figure 3c); something that points to the need to model (de-trend) this error to reduce this dependence. Methodologically, this implies a transformation $C_M \rightarrow C'_M$ such that the error in the transformed variable, $e'_c = C_T - C'_M$, is only weakly dependent on the underlying (and unknown) true compliance field. This error-modeling of the compliance introduces a set of parameters, β , that need to be estimated.

Flow modeling. The flow response relies on the compliance-to-permeability relation, from which we generate the fracture-permeability field K_T . We simulate flow on this permeability field, from which we extract a dynamic record of pressure (P_T) and production curves (S_T) at a discrete set of locations that represent well measurements. These records are subject to measurement errors, and therefore we denote the accessible, measured quantities as P_M and S_M , respectively. The parameters α generating this response are of course unknown. We run the flow model (G_P) and transport model (G_S) on estimates $\hat{K}_T(\hat{\alpha}, \hat{\beta})$ to obtain simulated responses \hat{P}_T and \hat{S}_T . The sets of parameters $\hat{\alpha}$ and $\hat{\beta}$ are then estimated by minimizing the error between the measured (P_M, S_M) and modeled (\hat{P}_T, \hat{S}_T) flow response. While sophisticated estimation and inversion procedures exist, our work on simple least-squares minimization procedure:

$$\min_{\hat{C}_T, \hat{\alpha}, \hat{\beta}} \left[\frac{P_M - G_P(\hat{K}_T(\hat{\alpha}, \hat{\beta}))}{\sigma_{v_p}^2} + \frac{S_M - G_S(\hat{K}_T(\hat{\alpha}, \hat{\beta}))}{\sigma_{v_s}^2} \right]. \quad (1)$$

SEISMIC INVERSION ON ORTHOGONAL DISCRETE FRACTURE NETWORKS

We test our approach on discrete fracture networks consisting of two sets of parallel, equidistant, connected fractures oriented at an angle of 0 and 90 degrees with respect to the x-axis. The fracture spacing is uniform and equal to 80m. On average, the mean value of x-directional compliance values are two times larger than the y-directional compliance values. Our compliance values vary between 10^{-10} and 10^{-9} m/Pa. We construct a spatially-correlated compliance field that follows a lognormal distribution with an exponential autocorrelation function in space (Figure 2a). We simulate seismic shot gathers using a 3D staggered grid finite-difference method (Fang et al., 2013) (Coates and Schoenberg, 1995; Willis et al., 2006). For seismic inversion, we apply the double-beam method (Zheng et al., 2013) to estimate the modeled seismic compliance field C_M .

ERROR MODEL FOR THE COMPLIANCE FIELD

By analyzing C_M obtained from the double-beam method, we find that the compliance measurement error, $e_c = C_M - C_T$,

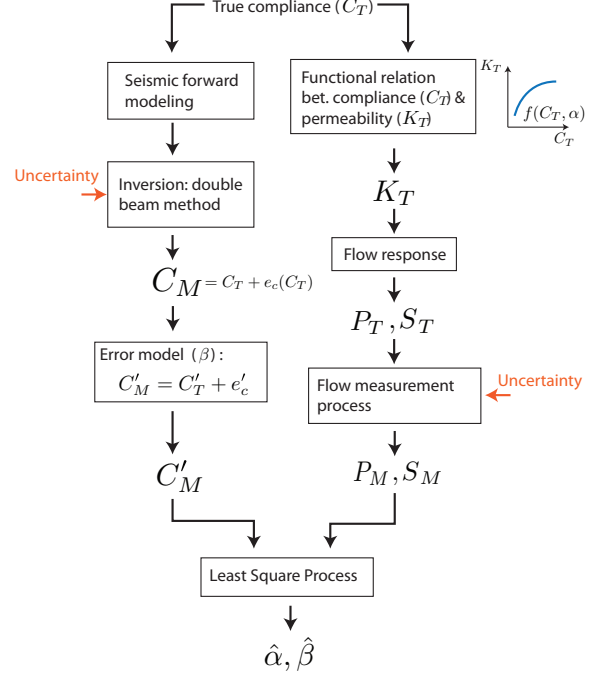


Figure 1: Overall framework for joint flow-seismic inversion. The above framework shows how seismic and flow models are integrated to better characterize fractured reservoirs.

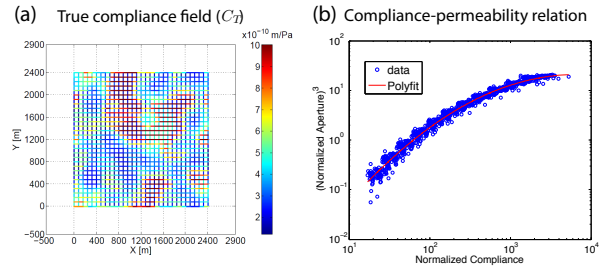


Figure 2: (a) Compliance field of the orthogonal discrete fracture networks that we study. (b) Functional relation between fracture compliance and permeability from rock-physics model; the parameter α determines the curve fitting (red line) to the data (blue circles).

is highly correlated with C_T itself (Figure 3). From the point of view of estimation, this is of course undesirable because it would require *a priori* knowledge of the true compliance field. Thus, one must introduce an error model that effectively de-trends the modeled response and weakens its dependence on the true compliance field. Our error correction model is motivated by the scatter plot between $C_T - C_M$ and C_T , which shows a linear trend (Figure 3d). From Figure 3d, we observe that $e_c \equiv C_T - C_M = \gamma(C_T - \langle C_M \rangle) + \varepsilon$ where ε is a random spatial variable that exhibits a much lower correlation with C_T . From these observations, and reorganizing, $(1 - \gamma)C_T = (1 - \gamma)C_M + \gamma(C_M - \langle C_M \rangle) + \varepsilon$. Therefore, we

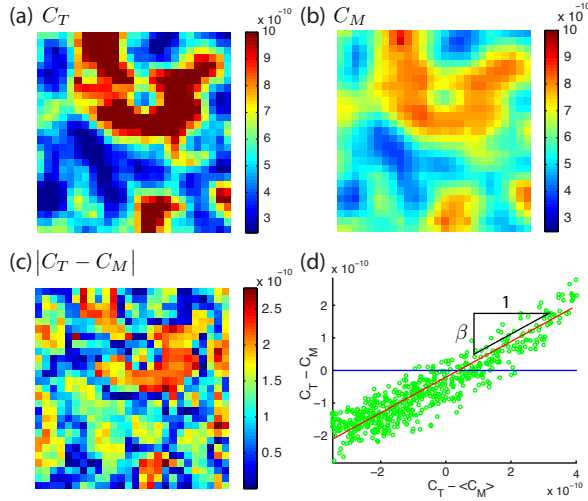


Figure 3: (a) True compliance field for the orthogonal discrete fracture network, interpolated to show the smoothed compliance field (C_T). (b) Modeled compliance field from double beam seismic model (C_M). (c) Difference between true compliance field (C_T) and seismic interpreted compliance field (C_M). We find a strong spatial correlation between the error (e_c) and the true compliance field (C_T). (d) Error ($C_T - C_M$) with respect to centered C_T ($C_T - \langle C_M \rangle$). We observe that C_M is compressed compared to C_T , and there is a linear relation between the error and the centered C_T .

define $C'_M = C_M + \beta(C_M - \langle C_M \rangle)$ with $\beta = \gamma/(1 - \gamma) > 0$ but unknown, and $e'_c = C_T - C'_M = \varepsilon$ can be modeled as an independent random function.

FLOW AND TRANSPORT MODEL

We study a simple flow setting: a quarter five-spot flow geometry with a no-flow condition at the boundaries of the fracture network, and fixed pressure values at the injection well ($\Phi = 1$ at the lower-left corner) and production well ($\Phi = 0$ at the upper-right corner). We simulate flow through the fracture networks by assuming Poiseuille’s law for the fluid flux u_{ij} between nodes i and j , $u_{ij} = -k_{ij}(\Phi_j - \Phi_i)/l$, where Φ_i and Φ_j are the fluid pressure values and k_{ij} is compliance-dependent fracture permeability. Imposing mass conservation at each node i and assuming incompressible flow, $\sum_j u_{ij} = 0$, leads to a linear system of equations, which is solved for the pressure values simultaneously at all the nodes. Once the fluxes at the links are known, we simulate transport of a passive tracer by particle tracking. We neglect diffusion along links, and thus particles are advected with the flow velocity between nodes. We assume complete mixing at the nodes. Thus, the link through which the particle exits a node is chosen randomly with flux-weighted probability (Kang et al., 2011).

UNIFYING FLOW AND SEISMIC MEASUREMENTS: LEAST SQUARES

Pressure and production curves can be obtained by solving the pressure and transport equations with the permeability field obtained from the C_T field. The objective is to find α (which characterizes the functional relation between K_T and C_T , Figure 2b), and β (which characterizes the error model of the compliance field, Figure 3d) by minimizing the objective function in Equation (1), that is, the sum of the absolute values of the difference between measured and simulated pressure (P_M and \hat{P}_T) and the difference between measured and simulated tracer production curves (S_M and \hat{S}_T) from the seismically-interpreted compliance field. As input for our least squares minimization procedure we used four measured well pressure data and a single production curve.

JOINT INVERSION RESULTS

Figure 4 shows the results obtained from our framework. We highlight three main results:

1. The error modeling of the compliance field was very effective: the error of the modified compliance ($e'_c = C_T - C'_M$, Figure 4a) is much lower than the error of the original modeled compliance ($e_c = C_T - C_M$, Figure 3c), and exhibits virtually no spatial correlation with the true compliance.
2. The functional relation between compliance and permeability was estimated accurately (Figure 4b), despite the paucity of dynamic flow data used.
3. The improvements in the estimates of the compliance field and the compliance-to-permeability relation lead to dramatic improvements in the predictability of the model, as evidenced by the ability of the model to *predict* the production curve for a different flow scenario in which the injection and production wells are located on a diametrically-opposite pattern (Figure 4c).

CONCLUSIONS

We have presented a new framework for joint inversion of seismic and flow data for improved characterization of fractured reservoirs. The key ingredient of our approach is to recognize that the seismic response and the flow response are linked through a fracture compliance-to-permeability rock-physics relationship. Our methodology is rather general, and was designed to be applicable to real field data, where the true compliance field is unknown, the compliance-to-permeability relationship is uncertain, and the flow data are noisy. Here, we have illustrated the potential of the framework through synthetic computer models of fractured reservoirs. We have shown that integrating seismic interpretation (through the double-beam method (Fang et al., 2013)) with flow modeling leads not only to robust parameter estimation, but also to reservoir flow models that are more predictive.

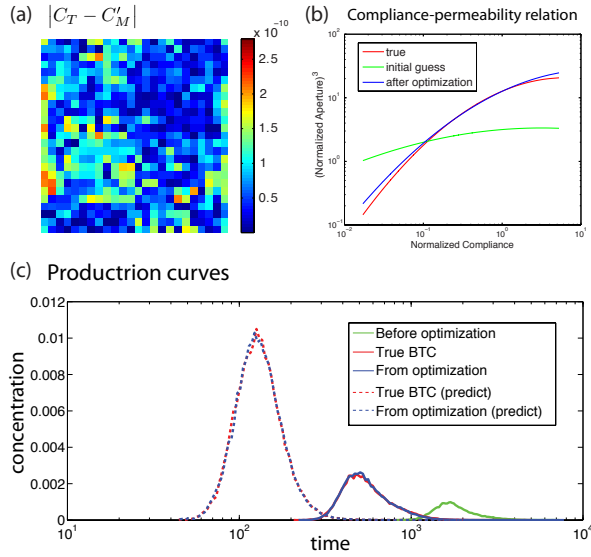


Figure 4: (a) Difference between the true compliance field (C_T) and the corrected seismically-interpreted compliance field (C'_M), which shows that the corrected compliance error ($e'_c = C_T - C'_M$) is small and virtually independent of the true compliance field C_T . (b) Estimated compliance-permeability relationship from joint flow-seismic inversion (blue line) accurately captures the true compliance-permeability relationship (red line); the green line is the initial input for our least square procedure. (c) Tracer production curves before (green solid line) and after inversion (blue solid line) compared with the measurements (red solid line). The dashed lines show the performance of the model in *predictive mode*, in which the model is used after inversion to predict the flow response for a different well configuration (a quarter-five spot with injector in the upper-left and producer in the lower-right corner).

ACKNOWLEDGMENTS

This work was funded by the Eni Multiscale Reservoir Science Project within the Eni-MIT Energy Initiative Founding Member Program.