Markov chain Monte Carlo methods (MCMC) applied to porous media flows

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ABSTRACT

Natural reservoirs exhibit high degree of spatial variability in their properties in multiple length scales. It has been established that such variability has a strong impact in determining fluid flow patterns in subsurface formations. Direct measurements of reservoir properties are only available at a small number of locations. Without an adequate description of the formation properties, such as hydraulic conductivity, porosity, and poromechanical parameters, the predictability of computational models is limited and tends to deteriorate over time. In this sense, history matching and uncertainty quantification are important research topics that aim at reducing the uncertainty in reservoir performance forecasting. Dynamic flow data are direct measures of reservoir responses and can introduce important information about subsurface processes. However, due to the non-linearity of the relations between flow data and reservoir properties, the integration of dynamic flow data directly in computational models by conventional geostatistics techniques is usually difficult. The problem of matching dynamic data can be formalized, as a inverse problem, in terms of Bayesian analysis and Markov chain Monte Carlo (MCMC) methods. The Bayesian framework allows quantifying the added value of information from several sources, while MCMC methods allows sampling from the *posterior* distribution in a computational framework. In the Bayesian formulation, a *prior* distribution of geologically consistent reservoir parameters must be assumed from *prior* geological information or generated using information from geostatistical analysis conducted on static data from core samples.

Recently, the role of geomechanics in subsurface petroleum reservoirs and freshwater-bearing formations is becoming increasingly important as deeper formations are detected and explored. Accurate predictions of fluid injection in weak rocks require a detailed coupled flow simulation and mechanical deformation modeling and demand precise understanding of the geomechanical factors affecting the hydrodynamics. During the exploration of a subsurface formation, changes in pore pressure trigger perturbations in the mechanical equilibrium of the porous medium leading to stress modifications, which alter rock properties such as permeability and porosity. Therefore, the subsurface properties (typically modeled by time-independent random fields) change with time and existing methodologies for uncertainty quantification and reduction are not applicable. We present a new Bayesian modeling framework that allows for the characterization of time-dependent rock properties along with the prediction of fluid flows in such formations. The new methodology has performed well to characterize time-dependent porosity and permeability fields in single-phase flows in heterogeneous deformable media, considering the concept of rock compressibility. Despite its simplicity, this problem gathers several characteristics of more complex models currently employed in the coupling of fluid flow and mechanical response of the reservoir solid structure.