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Modelling the permeability evolution of carbonate rocks

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ABSTRACT

Diagenesis is a major control on the distribution of porosity and permeability in carbonate rocks, and therefore impacts fluid flow in the subsurface. While changes in porosity can be directly related to diagenetic petrographic characteristics such as cement distribution and dissolution features, quantifying how these textures relate to attendant changes in permeability is more challenging. Here, we demonstrate for the first time how pore-scale models, representing typical carbonate sediments and their diagenetic histories, can be used to quantify the evolution of petrophysical properties in carbonate rocks. We generate 3D pore architecture models (i.e. the spatial distribution of solid and pores) from 2D binarized images, representing the typical textural changes of carbonate sediments following hypothetical diagenetic pathways. For each 3D rock model, we extract the pore system and convert this into a network representation that allows flow properties to be calculated. The resulting porosity and permeability evolution scenarios display several 'diagenetic tipping points' where the decrease in permeability is dramatically larger than expected for the associated decrease in porosity. The effects of diagenesis also alter the capillary entry pressures and relative permeabilities of the synthetic cases, providing trends that can be applied to real rocks. Indeed, values of porosity and absolute permeability derived from these synthetic 3D rock models are within the range of values measured from nature. Such diagenetic pathway models can be used to provide constraints on predicted flow behaviour during burial and/or uplift scenarios using 'diagenetic back-stripping' of real carbonate rocks.

1. Introduction

Carbonate rocks form significant hydrocarbon reservoirs and subsurface aquifers, but developing models of the porosity and permeability distribution as well as understanding the dynamics of fluid flow in these complex rocks is problematic (e.g. see review of Blunt et al., 2012). Current methods to predict subsurface flow use continuum-scale numerical simulations that operate on models where porosity and permeability is specified on a discretized grid. Such models also require multi-phase flow parameters, such as relative permeability (that is the flow of one immiscible fluid relative to another) and capillary pressure, but the determination of these parameters is usually dependent upon data derived from costly laboratory measurements that use small core plugs. These measurements are often, however, limited in number and so fail to capture the full variability, heterogeneity and multi-scale flow properties present in complex carbonate subsurface reservoirs (Knackstedt et al., 2004).

Carbonates often show highly heterogeneous and tortuous pore networks. This means that a conversion from porosity to permeability and multi-phase flow properties is far from straightforward (Blunt et al., 2012; Gomes et al., 2008; Hamon, 2003; Neilson and Oxtoby, 2008). Carbonate pore systems do not divide in a unique manner into pore bodies and pore throats, but rather are variously-scaled, complex pore systems that challenge such a simple classification. While several pore classifications have been proposed (e.g. Choquette and Pray, 1970; Mousavi et al., 2013; Lønøy, 2006; Lucia, 1995), these are based on petrographically observable textures alone and are not specifically related to single- and multi-phase flow properties of the rocks themselves. We therefore here consider the relationship between the pore system and the

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emergent fluid flow properties of carbonate rocks, using an approach in which the rock texture, which emphasises the solid components, defines the void space, and hence determines the emergent fluid flow characteristics.

The petrophysical properties of carbonates and the distribution of these properties within the subsurface, result from the original sediment grain type and fabric, the depositional architecture, and the diagenetic and structural events imposed during burial and/or uplift. Due to their highly reactive nature, carbonate rocks often display a strong post-depositional overprint (Fig. 1). Diagenetic processes such as cementation, neomorphism, dissolution, compaction and dolomitization can reduce or enhance porosity, so redistributing pore space and changing its relative volume, so altering both porosity and permeability as well as the multi-phase characteristics of the final carbonate rock (Flügel, 2004; Lucia, 2007). This paper focuses on the diagenetic aspects of carbonate rock evolution, and aims to demonstrate the value of a pore-scale approach in terms of understanding how the nature and timing of diagenetic events can provide the link between depositional sediment or facies classification and the subsequent flow properties of the final rock.

Extracting pore network models from pore space images provides a predictive power as such models represent both the multiphase flow dynamics and the geometry of the rock (Dong et al., 2008; Gharbi and Blunt et al., 2012; Ioannidis and Chatzis, 2000; Sok et al., 2010). There are two ways to compute properties in pore space. First, the direct approaches of discretizing the pores, usually via a Cartesian grid derived from a binarized, three-dimensional image, and then compute flow and transport on this grid (Blunt et al., 2012). This honours the actual geometry of the pore space as captured by imaging, but is computationally highly demanding. The second method is to extract a topologically representative network with idealised properties derived from the image, known as a network model. Flow and transport can then be computed semi-analytically through this network. This approach allows study of capillary-controlled displacement with effectively infinite resolution in the network elements, but makes a number of approximations concerning the pore space geometry (Blunt et al., 2012).

The most common method for generating three-dimensional (3-D) images of pore space is from micro focus Computer Tomography (μCT) scanning (Van Geet et al., 2000). Carbonate pore systems, however, often contain submicron features which lie below the resolution of μCT scanning tools, and this method often fails to capture the complete pore system, with its multi-scale pore-size distribution and connectivity over several orders of magnitude, which is a necessary input to accurately calculate permeability in carbonates (Knackstedt et al., 2004). Furthermore, CT scan images do not contain any diagenetic information: paragenetic sequences describing how the pore space has evolved through cementation, compaction and dissolution cannot be obtained from them.

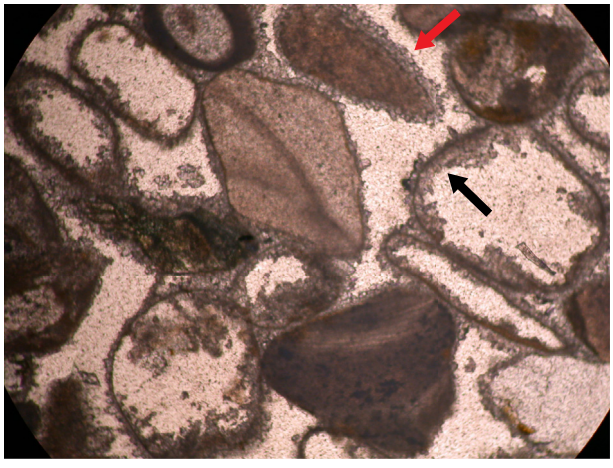

Figure 1. A typical reservoir carbonate rock thin section under polarised light showing both cementation and dissolution events. Red arrow indicates diagenetic cements forming on a grain; black arrow indicates cements forming after grain dissolution. Image approximately 0.8 mm across. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

An alternative approach is to create models of the pore space from 2D input images using thin sections and electron microscopy. Such images can be of much higher resolution than is the case for comparable-scale 3D CT images. Statistics of the spatial distributions of the components of the rock derived from 2D input images can then be used to create 3D images by means of stereology theory, using either multipoint-statistic techniques (Okabe and Blunt, 2004; Al-Kharus and Blunt, 2008) or using a stochastic approach involving a third-order Markov mesh (Wu et al., 2004, 2006; 2008).

The most popular approach for computing single and multiphase flow directly on pore-space images is the lattice Boltzmann method (e.g. Chen and Doolen, 1998; Kang et al., 2006). This is a particle-based technique that simulates the motion and collision of particles on a grid; the averaged behaviour can be shown to approximate the governing Navier–Stokes equation. This method is readily extended to multiphase flow by allowing particles representing fluid elements of two (or more) phases to be tracked. The reader is guided to the review of Meakin and Tartakovsky (2009) for discussion of further single and multiphase flow methods.

Network models are more flexible, in that they can accommodate irregular lattices, differences in wetting distribution and any sequence of displacement in two- and three-phase flow, as well as a variety of different physical processes, including phase exchange, non-Newtonian displacement, non-Darcy flow, reactive transport and thermodynamically consistent oil layers (see, for example Blunt et al., 2002; Lopez et al., 2003; Ryazanov et al., 2009). This allows for two- and three-phase displacement mechanisms and so predictions of relative permeability and transport properties based on pore-space images.

Using knowledge of the relative timing of porosity-enhancing or occluding diagenetic features, which is the usual output of a petrographic studies to derive a paragenetic sequence (Fig. 1), the textural consequences of these events could be artificially removed from a real thin section image ('diagenetic backstripping') in order to create images of the texture at former, successive, states of the rock. Using those back-stripped images, this technique would allow the flow properties to be calculated for each of these intermediate rock textures, thus linking the diagenetic evolution of the pore architecture to flow behaviour.

Here, we demonstrate this novel technique in a forward fashion. We begin with synthetic depositional rock textures which are progressively altered by a succession of typical diagenetic processes. Single- and multi-phase fluid flow results are obtained from extracting pore networks from resulting synthetic carbonate rock textures at different stages of diagenesis so enabling prediction of the porosity–permeability evolution of these synthetic cases, along with the related multi-phase properties, so linking conceptual depositional and diagenetic models together with the evolution of flow properties.

2. Methods: from rock texture to flow properties

2.1. From 2D image to 3D model

A three dimensional (3D) pore architecture model (PAM), comprising the spatial distribution of the solids and pores of a