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Gaussian field control and local upscaling for sandstone reservoir modelling using MRST

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Reservoir modelling is useful for oil industry for many reasons, such as to predict decline rates, optimize the hydrocarbon production, improve well placement strategies [1] and, above all, fully characterize the subsurface. In this account, mathematical models are invaluable during all the stages of reservoir characterization, as with for the spatial distribution of properties over the reservoir through geostatistical techniques.

Usually, it is not possible to predict how the fluids behave within a reservoir. Since their motion is highly dependent on the porous medium's texture, mathematical models that describe the rock-fluid interaction may be constructed to ease operational tasks and decision-makings. Permeability, for instance, is a property that grades how well the fluids flow throughout the pore space of a rock formation. In homogeneous reservoirs, the permeability is equal along all the tensor directions. However, in realistic reservoirs, heterogeneity is by far dominant, in which case the concept of directional permeability arises. Directional permeability is estimated by horizontal well test analysis and selective zonal well testing techniques, whereas the vertical permeability is measured by cutting a core plug taken from the wellbore [3].

The purpose of this work is to compare spatial distributions of porosity and permeability in petroleum reservoir models through Gaussian fields and upscaling techniques. Both procedures are carried out by numerical prototyping using the free open-source tool MRST (*Matlab Reservoir Simulation Toolbox*) [2] and applied to build primary synthetic models similar to oilfields found in Brazil's northeastern. Here, we model reservoirs using porosity and permeability datasets obtained from real well-logging measurements and yield spatial fields with localized variability around a unique well entity immersed into a cell-based discrete domain. Furthermore, we investigate different relations between horizontal and vertical permeability aiming to analyze variations under hypotheses of anisotropy. From the engineering point of view, the net effect of anisotropy is the loss or gain in effective permeability of a reservoir rock.

Let us consider the reservoir model as a cell-based discrete domain D (a regular box-shaped region), X the property (random variable) to be spread over D, z_k the real depth

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of the reservoir associated to the model's layer k, μ_k the mean value of X on k and σ a fixed value of standard deviation. Our objective is to compute $X(\mathbf{c})$, at each cell whose centroid is $\mathbf{c} = (i, j, k)$.

The procedure is given as follows: (i) read the well log information for the desired real-valued property (here, $X = \phi$, or $X = \kappa_m$, $m = x, y, z$, respectively standing for porosity or the principal components of the permeability tensor); (ii) apply a suitable Gaussian filter $\mathcal{G}_k$ per layer over X; (iii) transform it to be log-normally distributed; (iv) upscale the result from a fine grid to a coarser grid. Step (i) is achieved with a specific .LAS file-reading function from `SeisLab` package. To have (ii) and (iii), the following two operators are applied:

$$\begin{aligned} \mathcal{G}_k(X) &= \mathcal{G}_k(\mathbf{c}, \mu_k = \overline{X}(k), \sigma, \mathbf{L}) \\ \mathcal{F}_k(X) &= \exp(\mu_k + \sigma \mathcal{G}_k(X)), \end{aligned}$$

where $\mathbf{L} = (L_i, L_j, L_k)$ is the aperture of the 3D Gaussian kernel and $\mathcal{F}_k$ a transform.

Figure 1 depicts 3D realizations of ϕ spread over a $10 \times 10 \times 459$ fine grid and its coarser version with an aperture of $\mathbf{L} = (3, 3, 7)$. As seen, the upscaled version has the same range of porosity as the fine grid, but with 46 cells only along k, i.e. the Gaussian kernel produces a similar model which uses nearly 10 times less cells.

(a) (b)

Figure 1: 3D near-field porosity: (a) finer grid; (b) upscaled coarser grid.

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