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Single Effective Porous Medium Method for Modeling and Simulation of Flow in Fractures Carbonate Vuggy Oil Reservoirs

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ABSTRACT

Fluid flow in the macroscopic pore spaces cannot be simply assumed as a linear function of pressure gradient so that the application of Darcy's law to predicting hydrocarbon production in such highly heterogeneous reservoirs becomes questionable and often yields unsatisfactory results. Modeling and numerical simulation of the coupled fluid flow in naturally fractured carbonate karst reservoirs are extremely challenging due to non-Darcy flow in vugs and caves connected by fracture networks and deserve more effort and better ideas from both the engineering and computational sides. Many models have been developed in the past decade for the simulation of fluid flow in a naturally fractured reservoir and carbonate karst reservoirs. In this paper, We will use a continuum approach that combines the porous media, fractures, and cavities as a single effective porous medium and use effective porosity and permeability to approximate the fluid storage and transport behavior in the fractured vuggy oil reservoirs. Our model uses extended Darcy-Stokes-Brinkman formulation. This solution method is physically more straightforward, easier to derive and implement, and proves more apt to generalization from 2D to 3D cases than alternative techniques. The derived transient flow model is applied to several fine-scale 2D and 3D geological models. The results of these models form the foundation for future study of multi-phase and multi-scale reservoir cases.

INTRODUCTION

Vugs and fractures can significantly alter the effective porosity and permeability of carbonate reservoirs and should be accurately accounted for a geological model. Many models have been developed in the past for the simulation of fluid flow in a naturally fractured reservoir and carbonate karst reservoirs. Accurate modeling of the interaction between free-flow and porous regions is essential for flow simulations and detailed production engineering calculations. However, flow simulation of such reservoirs is very challenging because of the co-existence of porous and free-flow regions on multiple scales that need to be coupled. One of these is the extended Darcy-Stokes Model that consists of free flow in cavities and fractures characterized by Stokes equation and fluid flow in porous media by Darcy's Law. The coupled Darcy and Stokes equations are more difficult to solve, and additional boundary conditions need to be specified at the interface between cavities and porous media to guarantee continuity of mass and momentum across the interface. Other methods are based on the multiple-continuum concept that model fracture and vugs as porous media with high permeability values. These methods are also widely applied in the simulation of hydraulically fractured unconventional reservoirs since hydraulic fractures are no different from natural fractures in terms of the type of fluid flow therein. The specification of such boundary conditions requires fairly detailed knowledge of the location and extent of the interface which in turn makes the application of the Darcy-Stokes approach complicated. The Darcy–Stokes model consists of Darcy's law combined with mass conservation in the porous subdomain and the Stokes equations in the free-flow subdomain. To close the model, one must specify conditions on the interface between the Darcy and Stokes subdomains. All such conditions require continuity of mass and momentum over the interface but differ in the way they allow the tangential component to jump across the interface. In carbonate reservoirs, the porous and free-flow domains are not well separated. Vugs and rock matrix are crossed throughout the reservoir. This means that the coupled Darcy-Stokes approach does not yield satisfactory results for some reasons and needs precise information about the location and geometry of the interface between vugs and the porous matrix. This information can be obtained for a small rock sample but is generally not possible to obtain a full reservoir model. Moreover, explicit representation of the medium on a small scale, as required to resolve bugs and fractures, would make the flow problem time consuming computationally expensive. And lastly, the free-flow domains in general contain loose fill-in material or particle suspensions in the fluids filling the void space. So, when the extent of the hydrocarbon reservoir rock is very large, it is not possible to apply the Darcy–Stokes equations for the whole domain. Arbogast (2009), used tools from homogenization theory, to upscale the Darcy low from Darcy–Stokes equations on the microscale and then using a single set of basis functions that could be applied for the entire Darcy–Stokes system. Karper et al. (2009) used a unified discretization for the entire system. In our model, we have used another upscaling approach that was presented by Popov *et al*. (2007, 2009), in which the Stokes–Brinkman equations, instead of the Darcy–Stokes equations, are used on the fine-scale to calculate the upscaled effective permeabilities.

A mathematical model for vuggy fractured carbonate black- oil reservoir

We start by introducing the Darcy–Stokes, and Stokes–Brinkman models in more detail and discuss how to discretize the latter.

Incompressible flow in a porous rock matrix typically follows Darcy's law and is described by a first-order elliptic system in which Darcy's law is combined with a mass-conservation equation to relate the pressure. The Stokes-Brinkman equation provides a unified approach that avoids some of the problems encountered in the Darcy-Stokes system. This transient flow model consists of the Stokes-Brinkman equation and a generalized material balance equation which is an unsteady state and exact in the entire reservoir. Finite differences are implemented for the solution of the proposed transient flow model, which provides a smooth transition from standard multiple-porosity/permeability reservoir simulators. This solution method is physically more straightforward, easier to derive and implement, and proves more applications to generalization from 2D to 3D cases than alternative techniques. Following Darcy flow to combine mass conversation equation with the pressure p_D and the total velocity $\vec{u}_D$ we obtain the following system of equations:

$$\begin{cases} \nabla \cdot \vec{v}_D = f \\ \mu K^{-1}\vec{v}_D + \nabla p_D = 0 \end{cases} \qquad (1)$$

Here *K*is the permeability of the porous medium, μ is the fluid viscosity and denote the fluid sources, in our case the injector and producer well.

On the other hand, for the free domain we can write the Stokes equation as given below:

$$\begin{cases} \nabla \cdot \vec{v}_S = f \\ \mu\nabla \cdot (\nabla\vec{v}_S + \nabla\vec{v}_S^T) + \nabla p_S = 0 \end{cases} \quad (2)$$

The Darcy – Stokes – Brinkman equation is obtained combining the system of equations (1) and (2) into a single equation:

$$\mu K^{-1}\vec{v} + \nabla p - \tilde{\mu}\Delta\vec{v} = 0 \text{were} \nabla \cdot \vec{v} = f \quad (3)$$

In the general situation, the matrix is permeable, and there can be a flow between fracture and matrix. The mass conservation equation is then the same as before for the fracture but with additional source terms representing flow into the fracture from the matrix. Assuming for simplicity that elementary volume is constant in time and uniform in space, the equation becomes.

$$\frac{\partial(\emptyset\rho)}{\partial t} + \nabla \cdot (\rho v_f) = q_F + \frac{\rho}{e_V}(v_{MF}) \quad (4)$$

The idea behind the hybrid Darcy – Stokes – Brinkman formulation is to first remove the constraint that the normal velocity must be continuous across cell faces, giving a weak formulation that contains jump terms at the cell boundaries. Following **Knut–Andreas Lie e etc. (2009)** continuity of the normal component is then reintroduced using Lagrange multipliers, that is, by adding an extra set of equations, in which the pressure at the cell faces plays the role of the Lagrange multipliers. This procedure does not change v or p, but enables the recovery of pressure values element faces, in addition to inducing the desired change in the structure of the discrete linear system. The local equations can now be assembled to form a hybrid system of the form:

$$\begin{bmatrix} B & C & D \\ C^T & 0 & 0 \\ D^T & 0 & 0 \end{bmatrix} \begin{bmatrix} q \\ -p \\ \gamma \end{bmatrix} = \begin{bmatrix} 0 \\ f \\ 0 \end{bmatrix} \quad (5)$$

Here **q** is the vector of the outward fluxes, p is the vector of cell pressures, and γ the vector of face pressure and the entries of matrices are:

$$B_{ij} = \int \mu\vec{v}_i K^{-1}\vec{v}_j d\Omega, \quad C_{ij} = \int \delta_J \nabla \cdot \vec{v}_i d\Omega, D_{ij} = \int \delta_J |\vec{v}_i * \vec{v}_j| d\Omega, \quad (6)$$

We implemented our algorithm in MATLAB to see the differences between the two methods. In the second example, we have made use of MRST for a real case. In figure below we have a fractured vuggy reservoir with three principals directional of fracture orientations and a water injector well on the left corner and a producer in the right corner.

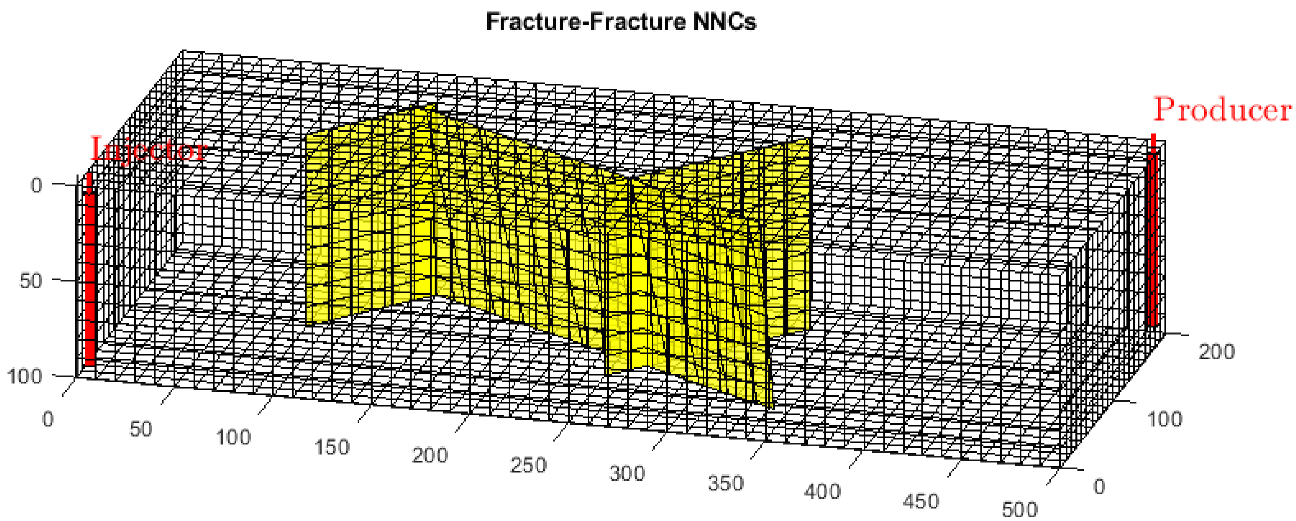

Figure No. 1: The geometry of a vuggy fractured reservoir with principal planes of fractures orientation and the injection and production wells

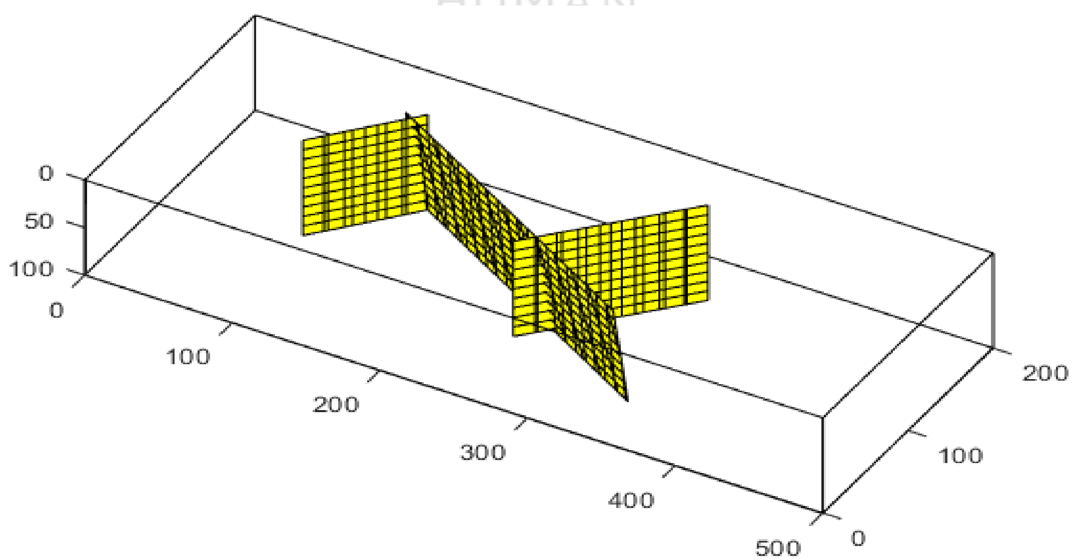

Figure No. 2: The three fracture planes with their principal orientations

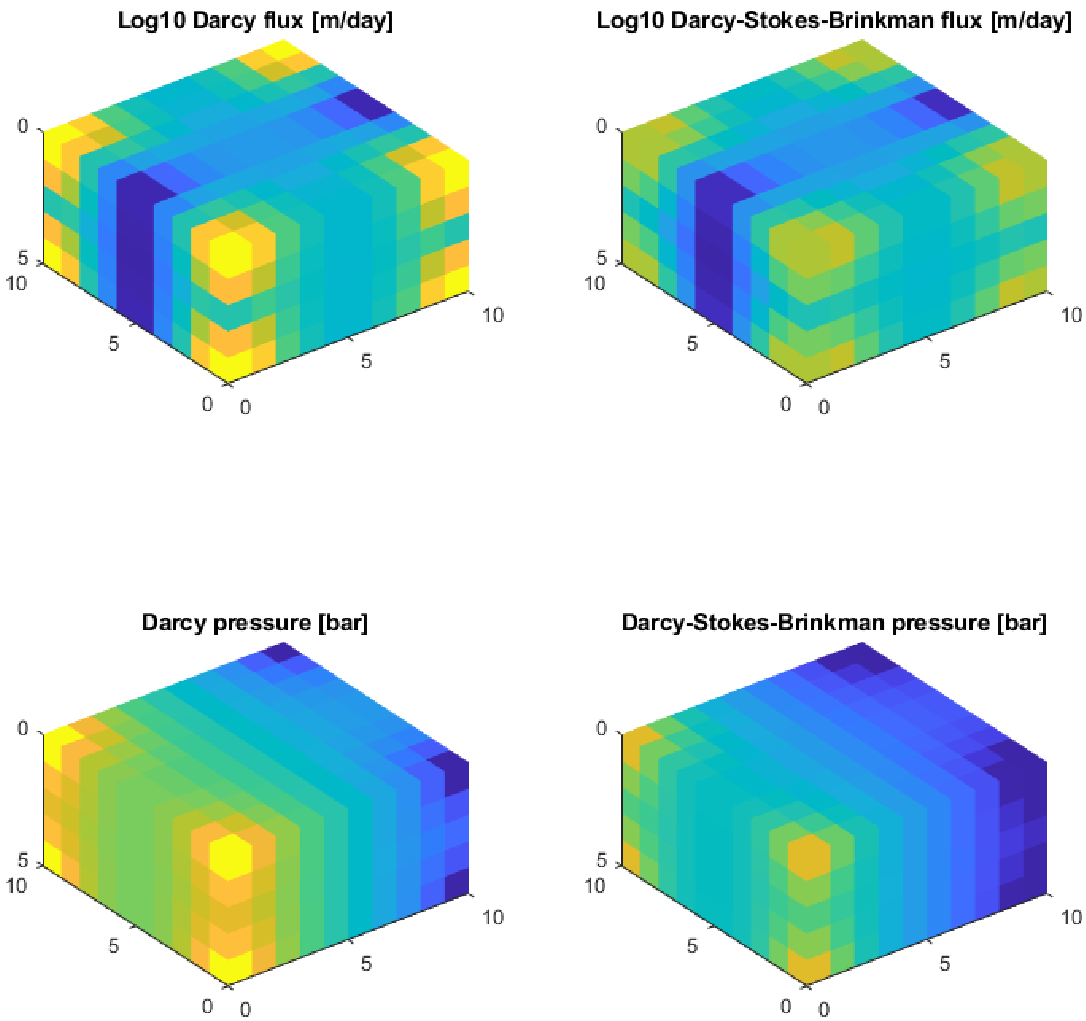

Figure No. 3: The differences between the two methods. The first one on the left is the distribution of Darcy flux and pressure and on the right are some parameters for the hybrid method of Darcy – Stokes – Brinkman for the same domain

After the simulation for 1820 day of water injection using the standard, the first alternative of simple Darcy law we obtain the following distribution of saturation where the yellow color yield the oil saturation and the blue one the water saturation (figure No.4).

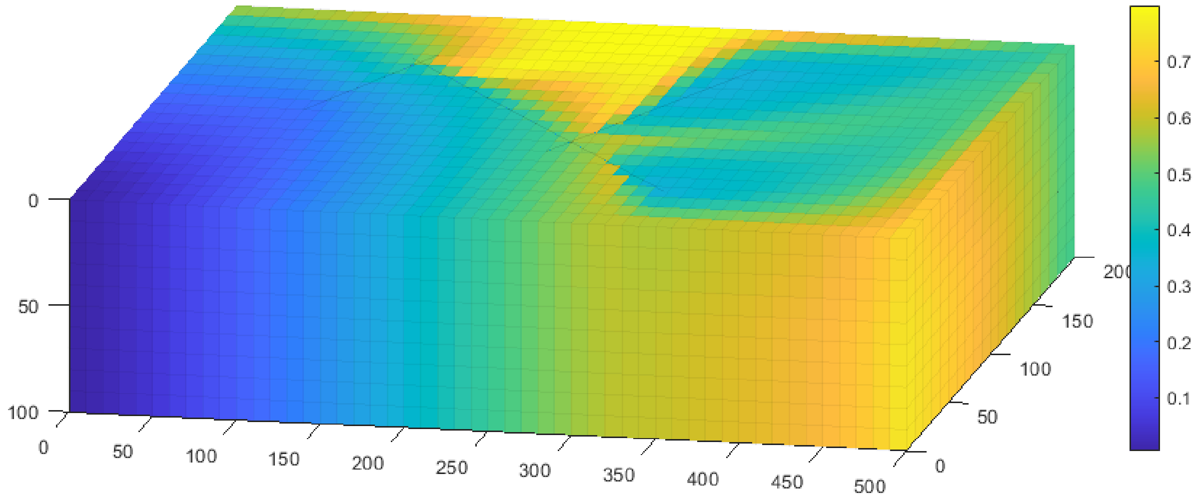

Figure No. 4: Distribution of saturations with oil (yellow) and water (blue) after 1820 day of injection of water with the implementation of simple Darcy flow in fractured vuggy carbonate reservoir

After the simulation for 1820 day of water injection using the hybrid, Darcy-Stokes-Brinkman formulation we obtain the following distribution of saturation where the yellow color yield the oil saturation and the blue one the water saturation (figure 5).

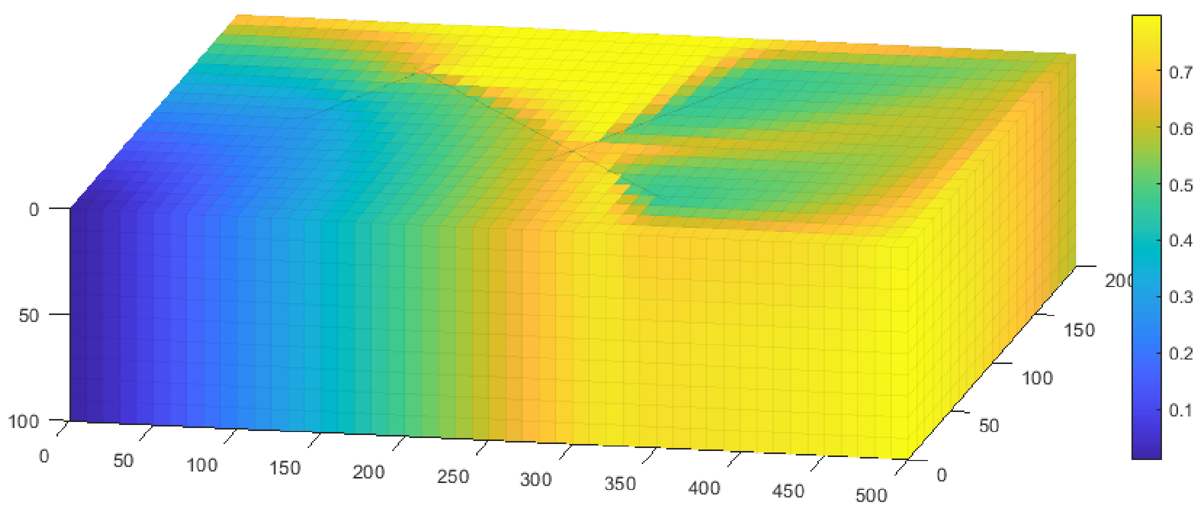

Figure No. 5: Distribution of saturations with oil (yellow) and water (blue) after 1820 day of injection of water with the implementation of Darcy-Stokes-Brinkmanformulation in fracture vuggy carbonate reservoir

In the following figures, we show the evolution of water injection well pressure performance for 1820 days and the corresponded oil reservoir rate from the producer.

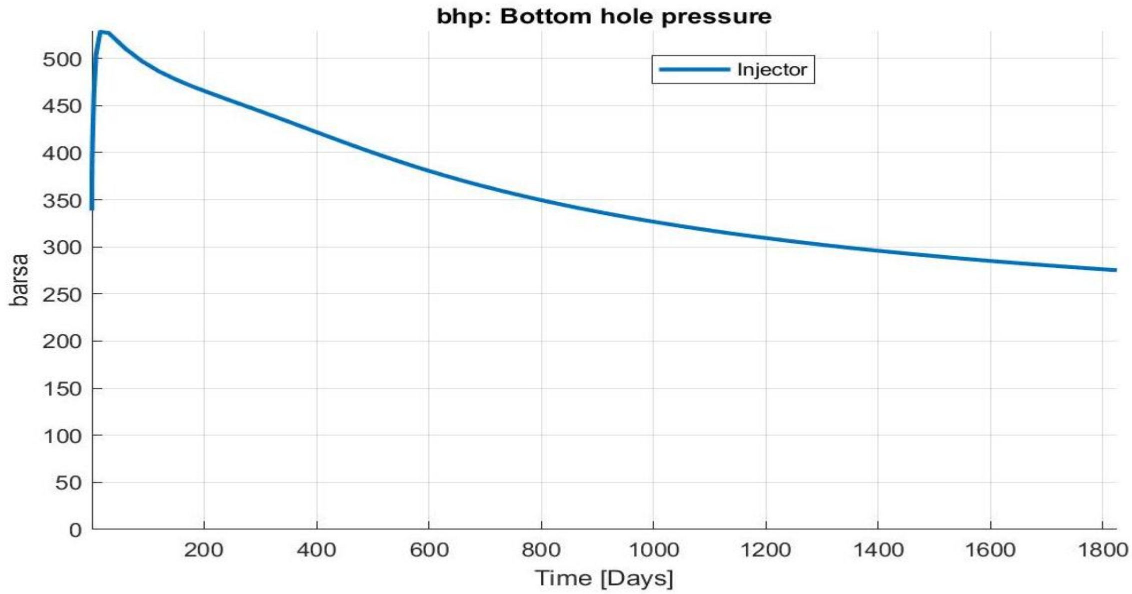

Figure No. 6: Evolution of water injection well pressure performance for 1820 days

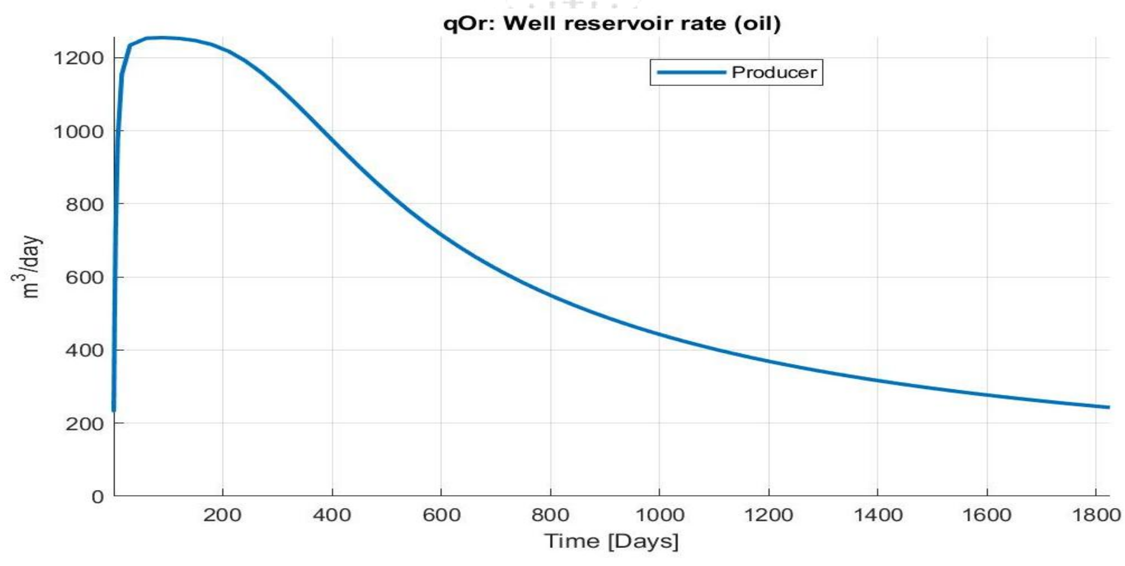

Figure No. 7: Evolution of well reservoir rate (oil) for 1820 days

CONCLUSIONS

As we see from figure no.4 and 5 there is a significant difference in considering both methods, when considering simply Darcy flow and the hybrid Darcy-Stokes-Brinkman one. In the second case, the yellow color predominates, which means there is more oil in the reservoir. But this does not mean that this method secures always a better or worst result. It only indicates that the two results are different and making complex, robust, rigorous, physical, and mathematical analyses we can show the existence and unicity of converged Darcy-Stokes-Brinkman formulation comparing with Darcy one. But this can be done in future work. Although the Darcy - Stokes–Brinkman model is a promising approach for simulating vuggy-fractured reservoirs, its discretization using the Taylor–Hood elements is relatively time-consuming and computationally expensive because of the high number of degrees of freedom. Hence, flow problems may fast become computationally intractable with increasing model sizes, in particular in 3-D. The method developed here has natural parallelism in the computation of basis function and also has the potential for reduced memory requirements, and may therefore be an efficient approach for hunting high-resolution 3-D models.

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