Fluid flow modelling in oil reservoirs

Martí Burcet Rodríguez

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Abstract

The modelling of fluids flow in oil reservoirs is a complex problem because of multiple phases interaction, different physical and chemical processes occurring at the same time and the subjection to many input data uncertainties.

Water, oil and gas are almost always present in reservoirs what difficult the characterisation of the fluid as a single component and needs to be treated separately. The interaction between phases is normally presented as diffusion between phases and as resistance to change in inter-facial geometry. Apart of this there are differences in the ruling principles at different scales: while at microscopic scale surface tension controls the fluid configuration, at macro-scale the rock heterogeneity's and fluid mobility rule the flow. The construction of the geological model and the measurement of properties are also sources of errors due to the difficulty of interpretation of studies or disruption of tests.

All these uncertainties have to be accounted by the numerical model in order to get a feasible solution of the flow in porous media. The best approach nowadays is a fully implicit technique based on grid blocks, but can give very large systems and sometimes can be ill-conditioned. To avoid this it is possible to improve the character of the problem by splitting it into a general pressure equation plus one conservation equation per component (solved explicitly). Other possibilities are solving the three-dimension governing system using FDM and FEM, but they are very computational costly and therefore not useful to do several simulations. New numerical methods have been applied to this problem (mixed FEM, multi-block and multi-scale, Stochastic, etc.) but they are not yet enough well developed to be used in reservoir simulation.

The numerical approaches to the fluid flow problem in oil reservoirs and the pros and cons of each one will be widely developed in the final presentation.

1 Introduction:

Numerical simulations of oil reservoirs are widely used by companies in different phases: in the decision making stage basically to predict the recovery profit of the investment, in the exploitation period they are done to know the flow rate that can be pumped out, when it will become unprofitable to continue pumping... So it is important to have an efficient method that could be run many times for decision and design purposes.

However it is not the simulation the principle source of errors. The characterisation of a possible or actual reservoir is subjected to lots of uncertainties arising from the fact that the reservoir rock can be placed thousands of meters below ground or sea label, it can be a difficult geological environment subjected to many discontinuities (faults, fails, slides, lithology...). In many cases the only way to assess these unknowns is by indirect methods based on geophysics such as seismic reflection, gravity and magnetic anomalies... Only few exploration wells can be drilled in many cases due to the cost which will provide only punctual sources of data of a 3D complex geometry. A widely range of scales can be considered, from microscopic roughness and void connection to geological discontinuities that can be principle directions of flow. From all these and maybe other analysis a geological model will be constructed and also some rock parameters (phase fraction, effective porosity, permeability, friction coefficient...) will be guessed. So all these amount of data subjected to a margin of error non negligible will be the base for the construction of a numerical model.

Apart from the uncertainties coming from the creation of the geological model and from the estimation of rock and fluid parameters, another important drawback to deal with in the numerical model is the complexity of the governing equations of the problem. Multiple phases are interacting in the porous media (normally oil, gas and water) and the interaction between them can be different in each case: diffusion of one phase in the others, convection, chemical reactions... These processes complicate the classical Darcy's law of flow in porous media in something much more complex.

Therefore the purposed model should be able to deal with all these data uncertainties and particularities of the governing equations of flow in oil reservoirs.

2 Compositional model:

In order to make this problem treatable during the years several models have been proposed making admissible simplifications that could reduce the size of the problem by decreasing the number of degrees of freedom of the numerical simulation. One common simplification is that the composition of the oil and gas are assumed to be constant and that solubility of gas in oil only depends on pressure. However if during the pumping process big changes in temperature or pressure are produced this composition may vary due to higher solubility, phase changes or chemical reactions. In that case a state equation should be introduced in order to account for the variation in time and/or space of the composition of the phases flowing.

The common unknowns in the flow simulation are the **mass fraction** of each phase in the others, **volume fraction** and the **pressure** of all phases in the volume element. All these unknowns are the degrees of freedom of each element that have to be solved at each time step with the following equations: **mass conservation** for all the components, **capillarity pressure relations** for all the phases, **phase constrains** that assures that the sum of mass fraction of all components in all phases is 1, one **saturation constrain** that assures that all phases are occupying the whole volume and **equilibrium equations** that rules how components in different phases are in thermodynamical equilibrium between them.

Again some uncertainties arise from the constitutive relations, one of this is how the interaction between different phases affect the permeability. What has been doing to evaluate this effect is to introduce different permeabilities for different relations between phases based on experiments. Also some studies have been carried out to construct a fully theory.

One option to reduce the size of the problem is to consider that the oil is not volatile, then it is possible to treat separately the components of gas and oil which are assumed to don't change its composition from the standard conditions. This case leads to the so-called **Black-oil model**

A more drastic simplification is to consider no mass transference between phases and no compressibility neither of the rock nor the fluid. These models are used for development of new numerical simulations as well as for very simple real cases.

3 Numerical Formulations:

The compositional models seen above are normally solved using fully implicit methods, but it normally leads to ill-conditioned matrices that don't give good results. To avoid this what is normally done is to split the problem in a pressure problem (balance of volume of all phases) and an equilibrium equation per component. This reformulated problem is solved using Implicit Method in Pressure and Explicit in Composition (IMPEC). This technique is restricted in the time stepping because it can give unstable solutions. To overcome this instability, another option is to instead of using an explicit method for components use also an implicit scheme for the saturation, the so-called IMPSAT method. The combination of both methods can also be an option using depending on the implicitness of the element (boundary or internal) the IMPEC or IMPSAT methods. This method is called Adaptive Implicit (AIM).

As mentioned before the number of degrees of freedom can be large as well as the domain of study, so the problems can be too heavy to run for the whole domain with a good mesh grid. An option used to get better solutions where it is needed is the Adaptive Mesh Refinement (AMR) that can be applied to improve the mesh near moving boundaries where the oil is moving out. For the same reason of time consumption it cannot be useful to run the full 3D problem using FEM or Finite Differences. Instead of this what is mostly done is to consider volume elements and solve the flow problem between neighbour blocks (block-to-block method).

Other possibilities are mixed finite elements or Stochastic finite elements with porosity and permeability as random variables is also an option to account for the uncertainties derived from the characterisation of the rock. If a higher resolution is required it is also possible to use multiblocks and multiscale methods.

In many cases, since the problem is subjected to so many uncertainties and covers a big zone, the solutions given by fine scale models can be few interesting. Instead of this what is more interesting is to use a coarser mesh that could give results with enough resolution for estimation purposes. This is the case of Upscaling Techniques and Multiscale Methods.

3.1 Upscaling Techniques

The clue characteristic that share all these techniques is the use of an analytical solution in large scales with data from local scale analysis. To relate the parameters obtained with the fine mesh with the coarse scale ones some special circumstances have to be accomplished.

An example of upscaling technique would be the study of a single phase steady flow in 2D. If there are two very different permeabilities in the space (one much fewer than the other) then if the slow scale is bigger than the fast one, it is possible to homogenise the permeability in a tensor only depending on the slow dimension. After this calculus at fine scale the coarse permeability can be obtained with average pressure gradients and average velocity field. Once the average permeability is calculated this can be used to run simulations directly in the coarse grid.

An improvement to the case posed before is the use of information of an extended region where the Boundary Conditions are applied, but the average coarse parameters are computed over a reduced block. Therefore the resultant parameters are less "local" and less influenced by the arbitrary domain and boundary conditions.

However, the upscaling techniques numerically can result in negative permeabilities. This fact can be overcome by imposing that the permeabilites have to be positive and run some iterations until the resultant model equals the global flow field. Another limitation of the coarse grid method and specially the upscaling techniques is that they consider a uniform pressure gradient which is not the case of pumping wells, that reduce very locally the pressure levels. Although this fact after some iterations it is possible to stabilise the flow and find proper permeabilities.

After single-phase upscaling flow problems it is possible to construct two-phases upscaling procedures. This is due the fact that flow parameters mainly depend only on the saturation of the coarse scale. However the upscaling of two-phases problems are very sensitive to the local boundary conditions imposed in the fine scale study and may not be robust to compute coarse flow parameters.

3.2 Multiscale Methods

Analogously, the Multi-scale method uses the same principle but with coarse equations posted numerically instead of analytically. These methods are based on FEM procedures solving transport equations at the fine scale instead of the flow one which is computational costly. Other approaches have been proposed solving locally the pressure equation or including a dispersivity term to consider velocity fluctuations at the small scale level.

Another option could be to use Variational Multiscale FEM where the discrete solution is considered to be the sum of a component of the small scale plus another of the coarse scale. Mortar upscaling method can handle neighbour blocks with non matching flows and different physical models.

As a conclusion of both Upscaling techniques and Multiscale methods, the more sophisticated the upscaling method is, the more accurate the velocity reconstruction will be and hence more precise the fine-scale saturation solution will be. However in many cases is the solution of the transport equation at the fine scale what affects the most the upscaled solution, not the multiscale treatment of the pressure, therefore it is in the fine scale where more effort and precision should be put.

4 Conclusions:

The modeling of flow in porous media applied in the oil industry is a very important study because is used to make decisions that involve a lot of money. Therefore it is crucial to have good predictors of how much oil can be pumped from a reservoir although the uncertainties to what it is subjected from the construction of the geological model and from the estimation of flow parameters. The complex interaction between phases and components present in the reservoir also enlarge the size of the system which have many degrees of freedom and elements. The most common approach is a global balance of mass and pressures per time step between element blocks, thermodynamical equilibrium between phases of components plus a saturation equation.

Regarding the numerical approximation, several options are used: IMPEC method is an Implicit Method in Pressure and Explicit in Composition, but the level of implicitness of the equations can give ill-conditioned matrices. IMPSAT is an alternative to reduce the implicitness because is both implicit in Pressure and Saturation. The problem can be solved with FEM, Finite Differences or Finite Volumes, the last one a good option because for the precision required. Upscaling Techniques and Multiscale Methods combine information solved at small scale locally to predict flow parameters either analitically or numerically and then use them at corse scale for fast and several simulations.

References

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