PETROLEUM RESERVOIR MODELLING – SCOPE FOR APPLICATIONS OF NEW TOOLS AND INSIGHTS IN GEOTHERMAL?

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ABSTRACT

This paper briefly reviews the currently available modelling tools in the petroleum industry in terms of solver strategies, well modelling, uncertainty modelling, geomechanical modelling and fracture flow. While the modelling problems that geothermal reservoir engineers face have some different physics involved since transport of both mass and energy is relevant in geothermal systems, it is still appropriate to try to understand where the state of the art lies in the petroleum industry lies. The works cited show that the petroleum reservoir engineering community has access to tools which can solve problems with large numbers of unknowns that allow highly resolved models of reservoir geology to be incorporated. Current well modelling methods allows for refinement of detail around and along wellbores. Sophisticated methods are also now being developed in the petroleum industry to tackle uncertainty modelling, and to handle coupled geomechanical modelling. Finally advances are being made in the suite of tools available to model fractured reservoirs.

1. INTRODUCTION

Reservoir engineers in the petroleum industry use flow simulation codes which solve for multiphase mass transfer in porous media (which may include fractures). In "black oil" models the model solves for mass transfer of oil, gas and water within the system – with pressure and phase saturations as unknowns. More complex "compositional" models track chemical composition of the phases in space and time with unknowns describing pressure, overall composition and vapour fraction. Finally "thermal" model include an energy balance in the system of equation being solved. These models are the most similar to the systems of equations addressed by geothermal flow models. In the petroleum industry such models are generally only used when additional thermal energy is injected into reservoirs in the form of hot water or steam. Other related modelling problems being addressed with petroleum engineering related reservoir simulation modelling codes include geo-sequestration of carbon dioxide in the sub-surface, production of coal-bed methane, and production of gas from gas hydrate reservoirs.

The petroleum industry has a much larger base of reservoir modelling researchers, code developers and users. The industry is concurrently trying to increase the numbers of unknowns that can be practically addressed in their modelling runs, and is finding ways to address the inherent uncertainty in the modelling process.

This paper outlines the current of state of the art in petroleum reservoir modelling technology in an effort to highlight technology which may have the potential to cross over into use in the geothermal community. For the mathematics which underlies each of the methods which is discussed readers are referred to relevant literature cited in the references section.

2. SOLVERS AND COMPUTING STRATEGIES

Code developers in the petroleum industry are reporting near linear- scaling of solution time with the number of unknowns in reservoir simulation codes that exploit GPUs. For example Esler et al. (2014) report on the performance of a black oil model that can solve equations governing multiphase phase fluid flow (without a corresponding energy) equation with up to 55 million model cells and achieve both very rapid run times and near linear scaling. That works uses a server that has eight NVDIA Tesla K40 GPUs and 12GB of graphics memory. Their GPU code is written using C for CUDA.

Esler et al. compare their run times to a non-GPU version of their code and report speed up factors of 27 to 430 in single CPU core runs, and 6 and 45 on multi CPU core runs for three field case studies. The greatest speed ups are observed in a field case study with 1.3 million modelling cells.

Researchers are also developing solvers and preconditioning strategies to tackle the systems of equations which arise from flow in heterogeneous porous media. In the petroleum problem the reservoir permeability can easily varying over several orders of magnitude within the domain. This typically leads to a system of rather ill-conditioned equations that can exhibit poor convergence. The equations are nearly elliptic in nature. To accelerate the solution process Manea et al. (2014) recently demonstrated that a two-stage algebraic multiscale (AMS) formulation (proposed by Wang et al., 2014) provides an efficient and scalable preconditioning strategy that they applied to models with up to 100 million cells. At its heart the multiscale method gains its advantages by being able to build an approximate fine scale pressure solution from a coarse scale solution using grid transfer operators. Manea et al.'s numerical experiments were performed on large shared memory machines.

3. WELL MODELLING

As in geothermal models it is typical in petroleum flow simulation models to use refined cells around wells to provide greater accuracy. These small cells are in regions where the flow velocity is at its highest which can limit the size of timestep that the models can take. Kheriji et al. (2014) have developed a novel approach that shows promising results by using a domain decomposition style method which allows for local time-stepping within the near well region, while the rest of the domain is time-stepped using larger timesteps. The efficacy of this approach is demonstrated on a gas injection gas model, and on a gas condensate model – both of which involves significant gradients in phase saturations near the well.

The details of near wellbore heterogeneity can also be captured through coupled simulation of the near-wellbore

and reservoir regions using updates to the well productivity (for example Ding, 2010.

Petroleum reservoirs run and develop codes which couple flow in the reservoir with flow in the wellbore (and beyond). Pourafshary et al. (2012) represents an example of current capability in this area. In this work a well model is demonstrated which can handle multiphase, compositional flow with a wellbore. Flash calculations are performed a long the wellbore and a temperature profile through the well's depth is predicted. The model is able to capture multiphase flow physics such as liquid hold-up.

4. UNCERTAINTY

Well placements in petroleum reservoirs are generally planned using reservoir simulation models. These models are subject to uncertainty since the underlying geological properties of the reservoir at any point in space are not typically known precisely. This means that any approach that aims to optimize well placements must do so under uncertainty. A modern approach to that problem is typified by Chang et al. (2014). Their work uses a multi-objective approach that allows many geological realisations to be considered. The method simultaneously maximises the mean net present value of the well (over the geological scenario) while simultaneously minimising the standard deviation of the net present value (i.e. minimising the risk of an extremely poor well performance by placing a well at a particular location). The underlying optimization method uses a form of the genetic algorithm to search the possible space of well locations.

Uncertainty evaluation/optimization approaches generally need many flow simulation runs to be performed compute their results. In the petroleum community the speed ups in the underlying simulation technology have paved the way for uncertainty and optimization problems to be addressed. Despite the advances in simulator design and in the ability of simulators to exploit modern computer architectures many in the petroleum reservoir engineering community agree that reduced order models, or proxy models, are likely to be an important part of the toolbox required to address uncertainty evaluation. Fillacier et al. (2014) demonstrates the use of proxy modelling in conjunction with Markov Chain Monte Carlo methods to quantify the uncertainty in future oil production from a field. Vidal and Archer (2014) present some initial results documenting applications of a Bayesian emulation proxy in a geothermal context.

5. COUPLED GEOMECHANICS

In both petroleum engineering and in geothermal coupled modelling of fluid flow and geomechanics is relevant. Microseismic monitoring is used in both domains to try to gain a better of understanding of geological structure and of the response of the subsurface to production or injection of fluid. Recent work by Jha and Juanes (2014) documents and compares the coupling of Abaqus to a commercial petroleum simulation code, and also of the open-source PyLith code to a research code for petroleum reservoir simulation. With the latter combination Jha and Juanes were able to run the model with two-way coupling between fluid flow and geomechanics. The coupling assumed quasi-static mechanical deformation by neglecting the inertia term in the momentum balance equation for the solid. This would be appropriate before fault rupture, but could not capture seismic wave propagation.

Jha and Juanes applied their modelling applied to CO2 sequestation, subsidence in producing oil fields and to flow along fractures and faults. In their subsidence modelling they found that the two way coupling approach did generate results which were different to any of the one-way coupling approaches they had considered.

Coupling PyLith to a geothermal simulator such as TOUGH2 (Press, 1990) is a research avenue that is worth of further consideration.

6. FRACTURE FLOW

Petroleum engineering has a range of tools available to characterise natural fractures and to model flow within them. Discrete fracture network models are gaining popularity where populations of fractures are stochastically populated into models with parameters that allow for a spatial varying fracture density and orientation. These models can be conditioned to well log and other geological data. Pressure transient analysis is also being used increasingly to condition discrete fracture network models, e.g. Pan et al. (2013), though in that case the authors acknowledge that characterizing natural fractures is a complex problem with a high degree of uncertainty.

The pressure dependent nature of fracture permeability is also receiving attention in the petroleum engineering community as the amount of natural gas produced from low permeability, naturally fractured shales increases in the US. Cho et al. (2012) observe that "correlations over practical ranges of pressure drop in shale reservoirs indicate over 80% reduction in fracture permeability, with most of the permeability loss occurring during the initial pressure drop". In any medium which is stress-sensitive this highlight to either acknowledge possible productivity drops, or to avoid them through pressure maintenance operations.

Simulation approaches which over the potential to model for induced seismicity have been demonstrated for test cases with a single fracture, e.g. McClure and Horne's (2011) study in an EGS context. It is not yet practical to extend the methodology they proposed to full field simulation with the full detail of geological structure and spatial hetereogenity in rock properties.

It is anticipated that progress on modelling in domains with geologically based fracture descriptions in the near term will come from methods that model large scale fractures specifically and then integrate the effects of smaller scale fractures into a dual continuum formulation. The embedded discrete fracture method (EDFM) method, exemplified by Moinfar et al. (2013), has been applied in unconventional hydrocarbon reservoirs to predict production. The method is computationally efficient and provides a means to calculate transfer properties between the fracture and dual continuum domains.

Detailed simulation of flow in fracture networks is possible using methods such as the Lattice Boltzmann method which does not require a computational grid to be generated. Archer (2014) demonstrated the application of this method to small 3D volumes containing both smooth and rough fractures. Geiger and Matthai (2012) used finite element methods to develop high resolution models of based on fracture patterns observed in outcrop. These models suggest that traditional dual continua models may oversimplify the physics of multi-phase flow in fractured media.

7. CONCLUSIONS

This paper has summarised some of the most recent developments in the modelling tools available in the petroleum industry. That industry has a large R&D basis and develops techniques that may be able to be leveraged for application in the geothermal community by careful consideration of the similarities and differences of the two subsurface flow problems. Strategies to do that are the subject of ongoing research.

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