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Development and application of near-well multiphase upscaling for forecasting of heavy oil primary production

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ABSTRACT

Near-well effects can have a strong impact on reservoir flow. Current reservoir modeling practice often uses coarse-scale flow simulation models, which may lead to biased results, compared with fine-scale models. In this work, we extend and apply a recently developed near-well multiphase flow upscaling technique to the coarse-scale simulation of heavy-oil primary production. For heavy oils, oil viscosity is a strong function of pressure when the pressure is below the bubble point. Therefore, the upscaled mobility functions (from near-well multiphase upscaling) depend on both pressure and saturation, which cannot be directly input to general purpose reservoir simulators. This is very different than the upscaled mobility functions for typical black-oil fluids, in which oil viscosity does not vary significantly with pressure. Accordingly, the upscaled mobility functions are often equivalent to upscaled relative permeabilities (as functions of saturation only). In this work, we develop two procedures to derive either the upscaled relative permeability or viscosity functions from the phase mobility functions, thus decoupling the dependency on pressure and saturation. It is found that the upscaled oil viscosity provides more accurate predictions than the upscaled relative permeabilities, especially at early time. This is because that the rapid change of pressure at the early stage of production is captured sufficiently in the upscaled oil viscosity (as a function of pressure). The use of upscaled viscosity function in multiphase upscaling is new, and has not been presented in previous studies. We also introduce a grouping technique to reduce the number of upscaled flow functions in coarse-scale models. This is based on an observation that there is a strong correlation between the upscaled flow functions and the coarse-scale well-block permeabilities. The proposed methods are applied to realistic models from heavy-oil fields. For cases considered, the near-well multiphase flow upscaling considerably improves upon the standard coarse-scale models. The use of upscaled relative permeability and viscosity functions, as well as the grouping of upscaled flow functions, provides practical applicability of the proposed method.

1. Introduction

Subsurface reservoirs are characterized by strong heterogeneity over multiple length scales. Highly detailed geological realizations are often generated to capture key fine-scale heterogeneity, which can strongly affect reservoir flow performance. Current reservoir modeling practice often applies coarse-scale simulation models, which may introduce significant bias with reference to the fine-scale models. To address this issue, various upscaling (coarse-scale modeling) techniques are developed to effectively capture the important fine-scale features in coarse-scale models. This work is focused on the modeling of near-well effects for heavy-oil reservoirs under primary production. In particular, we extend and apply a recently developed near-well multiphase flow upscaling technique to the coarse-scale simulation of heavy-oil production.

In reservoir simulation, upscaling techniques in general can be classified as upscaling of single-phase flow parameters and upscaling of multiphase flow functions. Recent reviews (e.g., Farmer, 2002; Gerritsen and Durlofsky, 2005; Durlofsky and Chen, 2012) provided discussions on various methods and outstanding issues. Single-phase flow upscaling considers absolute permeability, and is the most commonly applied upscaling technique in practice (e.g., Durlofsky, 1991; Pickup et al., 1994; Chen et al., 2003; Zhang et al., 2008; Wu et al., 2008). The upscaling of multiphase flow functions involves, in addition, rock-fluid properties (e.g., phase relative permeabilities). Those upscaled functions, often time dependent (e.g., as functions of saturation), are more challenging

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to compute than the single-phase flow parameters. Multiphase flow upscaling is especially needed for cases with large coarsening ratios and/or high fluid-mobility ratios. For reviews and recent developments of multiphase flow upscaling, refer to, e.g., Barker and Thibeau (1997), Christie (2001), and Chen and Li (2009).

For oil recovery from petroleum reservoirs, most flow is driven by wells. Therefore, the modeling of near-well effects is of practical importance. For example, in primary production (considered in this work), reservoir pressure decreases with time due to the lack of injection to maintain the reservoir pressure. At the early time of production, there can be a rapid pressure change (decline) in near-well regions, which can significantly impact the oil production. In fact, with the pressure decreasing, solution gas that is initially dissolved in oil will be released as free gas. The appearance of the free gas can then act to reduce the oil (and water) flow rates in the near-well regions due to the relative permeability effects. As a result, the grid resolution around wells can be crucial for appropriately modeling the release of free gas and the phase interference effects. It is known that standard coarse-scale models are often not sufficient to capture the interactions between multiphase flow effects and the subgrid variation of pressure and saturation within coarse blocks.

Previous studies on the coarse-scale modeling in near-well regions range from the near-well single-phase flow upscaling (e.g., Ding, 1995; Durlofsky et al., 2000; Muggeridge et al., 2002; Chen and Wu, 2008) to specialized near-well treatments on multiphase flow functions (e.g., Emanuel and Cook, 1974; Hui and Durlofsky, 2005; Nakashima and Durlofsky, 2010). Related work also includes a generalized pseudopressure well treatment (Fevang and Whitson, 1996), which was specifically applied to the modeling of gas-condensate well deliverability. Most recently, Nakashima et al. (2012) introduced a near-well multiphase (NWMP) upscaling procedure for general three-phase black-oil models. This approach entails solving local fine-scale well-driven flow problems in near-well regions to determine the appropriate multiphase flow functions. Those upscaled flow functions (i.e., formation volume factors, solution gas-oil ratio, and phase mobility functions) are computed in a manner to maintain the fine-scale near-well flow behaviors in the coarse-scale models.

In this work, we consider the near-well multiphase upscaling approach presented by Nakashima et al. (2012), and apply it to the coarse-scale simulation of heavy-oil primary production. Note that for typical black-oil fluids, the upscaled phase mobility functions (from the NWMP upscaling) depend only on saturation, as phase viscosities are almost constant to pressure. However, for the heavy-oil fluid system considered here, the oil viscosity is a strong function of pressure, especially in the near-well region, where the pressure is below the bubble point. Therefore, the upscaled phase mobility functions here depend on both the saturation and pressure, which cannot be directly input to general purpose reservoir simulators. To address this issue, we develop two procedures to decouple the dependency of the upscaled mobility functions on saturation and pressure. Specifically, we compute either the upscaled relative permeability (as a function of saturation) or the upscaled viscosity (as a function of pressure) from the mobility functions. Those upscaled relative permeability and viscosity functions can then be readily applied in any existing reservoir simulator.

To our knowledge, the use of upscaled viscosity functions in multiphase flow upscaling is new. It has not been studied in any previous work for the multiphase flow upscaling. This approach is introduced here, uniquely for the modeling of heavy oil production, as the oil viscosity depends strongly on pressure. In fact, it is shown that the use of the upscaled viscosity provides better accuracy than the upscaled relative permeabilities (which are often applied in multiphase flow upscaling), especially at the early stage of production. This is due to the fact that at the early time, there is a steep change (decline) of pressure in the near-well region, and this effect is sufficiently captured by the upscaled oil viscosity (as a function of pressure), but not by the upscaled relative permeability (as a function of saturation).

We apply our proposed methods to several sector models with realistic heavy oil fluid properties (covering a wide range of oil viscosities, from 10^2 cp to 10^4 cp), and under primary production from horizontal wells. For heterogeneous permeability fields, a grouping technique is also introduced to reduce the number of upscaled flow functions in the coarse-scale models. It is based on the observation that there exists a strong correlation between the upscaled flow functions and the coarse-scale well-block permeabilities. For all the cases considered, the coarse-scale models with near-well multiphase flow upscaling significantly improve upon the standard coarse models, providing solutions very close to the fine-scale predictions. The calculation of upscaled relative permeability and viscosity functions, as well as the grouping of upscaled flow functions, provides practical applicability of the NWMP upscaling in coarse-scale simulation.

This paper proceeds as follows. We first present the governing equations and coarse-scale models for general three-phase black-oil problems, including the modeling of near-well effects. Next, the near-well multiphase upscaling procedure (Nakashima et al., 2012) is briefly described. We then present our methodology to compute the upscaled relative permeability and viscosity functions, and the grouping of upscaled flow functions. The methods are applied to three sector models for the heavy-oil primary production from horizontal wells. Detailed numerical results demonstrate the efficacy and practical applicability of the proposed methods. We conclude with discussion and summary in the last section.

2. Governing equations

2.1. Fine-scale equations

We consider a three-phase, three-component system containing oil, gas and water in porous media. The oil and water components exist only in their respective phases, i.e., there is no mass transfer between these two phases. The gas component, however, can exist in either the gas phase or the oil phase (i.e., as dissolved gas). The governing equations describing the flow are formed by combining Darcy's law for each phase with a statement of mass conservation for each component. With capillary pressure effects being neglected (as in field-scale simulations, convection and/or gravity are the dominant flow mechanisms), the governing equations can be written as

$$\nabla \cdot \left[\frac{\lambda_o}{B_o}\mathbf{k}\cdot(\nabla p-\rho_o g\nabla D)\right]=\frac{\partial}{\partial t}\left(\phi\frac{S_o}{B_o}\right)+q_o^w, \tag{1}$$

$$\nabla \cdot \left[\frac{\lambda_w}{B_w}\mathbf{k}\cdot(\nabla p-\rho_w g\nabla D)\right]=\frac{\partial}{\partial t}\left(\phi\frac{S_w}{B_w}\right)+q_w^w, \tag{2}$$

$$\nabla \cdot \left[\frac{\lambda_g}{B_g}\mathbf{k}\cdot(\nabla p-\rho_g g\nabla D)+R_s\frac{\lambda_o}{B_o}\mathbf{k}\cdot(\nabla p-\rho_o g\nabla D)\right]$$
$$=\frac{\partial}{\partial t}\left[\phi\left(\frac{S_g}{B_g}+R_s\frac{S_o}{B_o}\right)\right]+q_g^w, \tag{3}$$

where $\mathbf{k}$ is the absolute permeability tensor (assumed to be diagonal here, but can be highly variable in space), ϕ is the porosity, p is the pressure, S_j designates saturation (volume fraction) of phase j (where $j=o$, w, g, representing oil, water, and gas), $\lambda_j=k_{rj}/\mu_j$ is the phase mobility (with k_{rj} being the relative permeability to phase j, and μ_j the phase viscosity), B_j is the formation volume factor, defined as the ratio of the volume of