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A Compositional Wellbore/Reservoir Simulator to Model Multiphase Flow and Temperature Distribution

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Abstract

Production of hydrocarbon often involves gas and liquid (oil/water) concurrent flow in the wellbore. As a multi-phase/multi-component gas-oil mixture flows from the reservoir to the surface, pressure, temperature, composition and liquid holdup distributions are interrelated. However, nearly all two-phase wellbore simulations are currently performed using “black oil” simulators. In this paper, a compositional-wellbore model coupled with a reservoir simulator to compute pressure and temperature distribution is presented. In this work, compositions of liquid and gaseous phases in the wellbore can be determined by three-phase equilibrium flash calculations and by considering the slip between phases. Our simulator has the capability of predicting the temperature profile in the wellbore, which helps to predict multiphase flow physics such as liquid holdup and pressure drop more accurately. As the wellbore model is coupled with a reservoir simulator, it can be used as a tool to calculate fluid-flow compositions between reservoir and wellbore. The simulated results of our compositional model were compared to the equivalent blackoil model for pressure and temperature distribution. Although the input requirements and computing expenses are higher for compositional calculations than for blackoil, our simulations show that in some cases, such as those involving highly-volatile oil and retrograde condensate gas, ignoring compositional effects may lead to errors in pressure profile prediction for the wellbore.

1. Introduction

As hydrocarbon is produced from a wellbore, pressure drop occurs due to gravity, friction and acceleration. Correct estimation of pressure drop is essential in artificial lift design calculations and well productivity computations. Different empirical correlations are available to model pressure drop in wellbores, such correlations have been published by Duns et al.¹, Hagedorn et al.², Orkiszewski³ and Beggs et al.⁴. The range of applicability of these correlations depends on several factors, such as tubing size, oil gravity, gas-liquid ratio and water cut. Solution methods have recently shifted to the mechanistic modeling approach due to the inability of correlations to simulate various cases. The main procedure of mechanistic modeling consists of the determination of flow regimes and the prediction of flow characteristics in the wellbore. Different mechanistic models such as Hasan and Kabir⁵, Ansari et al.⁶ and Aziz et al.⁷ are available in literature. Produced gas and oil phases consist of different components such as methane, ethane, propane and other hydrocarbons. However, in most of the available pressure loss models, pressure calculations are performed based on the simplified blackoil equations. The basic assumption in the blackoil approach is to consider three distinct phases: gas, oil and water phase. Oil and gas phases are recognized with oil specific gravity and gas specific gravity, respectively, which are assumed to remain constant in the wellbore. In a blackoil model, the gas can be dissolved in the oil phase. A blackoil model usually treats PVT properties of hydrocarbon phases as single functions of pressure and temperature. Hence, oil and gas properties such as density, viscosity and specific volume are computed by experimental correlations at each pressure and temperature. Empirical correlations are applied to calculate dissolved gas in the oil phase. With the blackoil approach, the effect of compositions on pressure and temperature changes is neglected.

The main question in using blackoil approximation is its validity. When the flowing liquid and gas are composed of more than one component, the effect of compositions on pressure profile, temperature distribution and fluid flow properties should be considered. One approach is to use a more complicated compositional method instead of blackoil approximation. The term