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 two-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.

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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 and Ros (1963), Hagedorn and Brown (1965), Orkiszewski (1967) and Beggs and Brill (1973). 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 Kabir (1988), Ansari et al. (1994) and Aziz and Petalas (1998) are available in the 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 "compositional" implies that the in-situ fluid composition may vary point by point in the wellbore as functions of pressure, temperature and slip between the phases. When the compositions are known, fluid-flow properties are obtained from the phase behavior calculations. Several authors such as Gregory

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Nomenclature

A	Wellbore area, ft^2
f	Fugacity
F	Molar rate of production, lbm mol/(ft^3 day)
g	Acceleration owing to gravity, ft/s^2
h	Fluid enthalpy, Btu/lbm
H	Liquid holdup
G	Gas phase fraction in equilibrium
K	Equilibrium ratio
$\overline{K}$	Permeability tensor, Darcy
k_r	Relative permeability
L	Phase mole ratio in mixture
L_e	Liquid phase fraction in equilibrium
L_{ne}	Liquid phase fraction not in equilibrium
$m_t^{\cdot}$	Molar flow rate for ith component between wellbore and reservoir, lbm mol/day
M	Molecular weight, lbm mol/lbm
n_c	Number of components
n_p	Number of phases
N	Overall concentration of component i
$\overline{N}$	Molar flux vector, lbm mol/ft
P	Pressure, psi
q	Molar flow rate, lbm mol/day
q_H	Enthalpy injection rate per unit rock volume, Btu/lbm s
q_L	Heat loss to the over- and underburdens per unit rock volume, Btu/lbm s
Q	Heat transfer rate to the wellbore, Btu/(h ft)
R	Gas constant
S	Saturation
T	Temperature, °F
u	Sum of internal energies per unit rock and the fluid contained in the unit rock, Btu/lbm
v	Fluid velocity, ft/s
v	Mole fraction of gas in absence of water
$\overline{v}_j$	Molar volume of phase j
V	Volume, ft^3
W	Overall concentration, lbm mol/ft^3
x_i	Molar fraction of ith component in liquid phase
y_i	Molar fraction of ith component in gas phase
z	Phase compressibility
Z	Overall hydrocarbon composition

Greek symbols

α	Phase volumetric fraction
ρ	Density, lbm/ft^3
θ	Wellbore angle, radian
ϕ	Porosity
ϕ_{ij}	Fugacity coefficient of component i in phase j
ξ	Molar density, lbm mol/ft^3
λ	Mobility ratio, Darcy/cp
γ_j	Gravity term for phase j, defined as $p_j\, g$
μ	Viscosity, cp

Subscripts

b	Bulk
i	Component
j	Phase (1 for oil, 2 for gas)
g	Gas
l	Liquid
o	Oil
S	Standard condition
T	Total