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Numerical modeling of steam injection in heavy oil reservoirs

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HIGHLIGHTS

- A reliable model is introduced for studying steam injection in heavy oil systems.
- A robust numerical solution is proposed to solve the latter model.
- Its reliability is successfully examined against independent data.

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ABSTRACT

In this communication, a three-dimensional, three-phase numerical model is presented for simulation of steam injection in heavy oil reservoirs. Formulation details, numerical solution method, and computational results are presented. The model includes the effects of three-phase relative permeability, capillary pressure, and temperature and pressure-dependent fluid properties. Interphase mass transfer of water-steam is allowed, but the oil is assumed nonvolatile and the hydrocarbon gas is insoluble in liquid phases. The three-phase mass balance and the energy balance equations are solved simultaneously using finite difference method. Some steam injection laboratory data are used for studying the accuracy of this model. Comprehensive and comparative studies together with extensive sensitivity analysis among various important parameters are conducted to understand steam injection performance in the heavy oil reservoir. This work indicates that steam injection can improve oil recovery from almost zero up to nearly 60% during a fixed period of time. In addition, it shows that only 30% of OOIP can be recovered by hot water injection method. The results demonstrate that there is an optimum time for oil production that is determined according to the flow of oil production and steam–oil ratio (SOR).

1. Introduction

Low API and high viscosity of heavy oil cause low primary production from heavy oil reservoirs. EOR processes attempt to recover oil beyond the primary production methods, or what is left. EOR methods are classified by the main mechanism of oil displacement. There are really just three basic mechanisms for recovering oil from rock other than by water alone. The methods are grouped according to those which rely on (a) a reduction of oil viscosity, (b) the extraction of the oil with a solvent, and (c) the alteration of capillary and viscous forces between the oil, injected fluid, and the rock surface. Enhanced oil recovery (EOR) methods are therefore classified into the following three categories [1]:

- Chemical methods (injection of chemicals/surfactants).

Chemical EOR, including polymer and surfactant-based processes [2,3], commonly requires large volumes of injection chemicals, as well as demulsifiers to recover more oil by either one or a combination of the following processes: (1) mobility control by adding polymers to reduce the mobility of the injected water, and (2) interfacial tension (IFT) reduction by using surfactants, and/or alkalis [4]. In addition, the amphipathic emulsifiers, due to its high affinity for the oil–water interface and its ability to orient itself at the interface to form a hydrophilic film around the oil droplets help the recovery process from oil reservoirs [5,6]. In recent years, the proportion of the amount of oil production obtained by using the Chemical EOR techniques to the total

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Nomenclature

A	block area, ft^2	U_w	internal energy of water, Btu/lbm
c_i	heat capacity of phase i	v_b	block volume, ft^3
c_R	compressibility of reservoir rock	α_c	unit conversion coefficient
H	height, ft	β_c	unit conversion coefficient
k	permeability, Darcy	β_i	thermal expansion coefficient, $°F^{-1}$
k_{ri}	relative permeability of phase i	γ	specific gravity, $\gamma = \rho_g$, psi/ft
k_{rs}	relative permeability of steam	γ_g	gas specific gravity, psi/ft
k_{ro}	relative permeability of oil	γ_o	oil specific gravity, psi/ft
k_{rw}	relative permeability of water	γ_w	water specific gravity, psi/ft
k_H	heat capacity of rock reservoir, Btu/°F ft day	δ	time difference operator, $\delta T = T^{n+1} - T^n$
p_i	pressure of phase i, psi	Δ	difference operator
p_c	capillary pressure, psi	ρ_i	density of phase I, lbm/ft^3.
p_s	gas pressure, psi	ρ_{ref}	reference density, lbm/ft^3.
p_o	oil pressure, psi	ρ_g	gas density, lbm/ft^3.
p_{wf}	well pressure, psi	ρ_o	oil density, lbm/ft^3.
q_{conv}	steam condensation rate, bbl/day	ρ_R	rock density, (lbm/ft^3).
q_H	heat flow rate, Btu/day	ρ_w	water density, lbm/ft^3.
q_i	flow rate of fluid of i, bbl/day	μ_g	gas viscosity, cp
q_L	heat loss, Btu/day	μ_o	oil viscosity, cp
T	time, day	μ_w	water viscosity, cp
U_R	internal energy of rock reservoir, Btu/lbm	φ	porosity
U_s	internal energy of steam, Btu/lbm	φ_0	initial porosity
u_i	velocity of fluid i		

annual amount of oil production has been increased rapidly. For instance, in China, the production by using the Chemical flooding method has been increased almost 10 times [7].

- Miscible gas injection methods (injection of a solvent).

Gas injection, especially CO_2, is another popular EOR method, and is applicable to light oil reservoirs, in both carbonates and sandstones. Gases used include CO_2, natural gas or nitrogen. Natural gas is injected in order to increase the pressure within the reservoir and thus induce the flow of crude oil or else sequester gas that cannot be exported [8]. The fluid most commonly used for miscible displacement is carbon dioxide because it reduces the oil viscosity and is less expensive than liquefied petroleum gas. Its popularity is expected to increase for two reasons: increased oil recovery through miscibility and disposal of a greenhouse gas.

- Thermal methods (injection of heat).

Thermal EOR methods are generally applicable to heavy, viscous crudes, and involve the introduction of thermal energy or heat into the reservoir to raise the temperature of the oil and reduce its viscosity. Steam (or hot water) injection and in situ combustion are the popular thermal recovery methods.

Three common methods involving steam injection are cyclic steam stimulation (huff and puff), steam flooding and steam assisted gravity drainage (SAGD). In situ combustion involves the injection of air, where the oil is ignited, generates heat internally and also produces combustion gases, which enhance recovery [1].

Thermal recovery methods are the most best for increasing production from heavy oil reservoirs, because thermal methods reduce the viscosity of heavy oil and increase its mobility and as a result, make the economical use of heavy oil reservoirs possible. Steam injection is currently used as one of the most successful enhanced oil recovery methods for heavy oil reservoirs [9]. This process involves simultaneous heat, mass, and fluid transport in the heavy oil reservoir, which aims to increase the oil recovery efficiency. It has been widely claimed that viscosity reduction plays a key role in increasing the oil recovery efficiency during thermal processes. Extensive studies have been performed to model steam injection process mathematically for prediction of oil recovery. Early efforts in mathematical modeling of thermal methods [10] concentrated on simulation of heat flow and heat loss. Later, series of linear and two-dimensional models were developed that solve mass balance along with the energy balance equation [11]. Shutler [12,13] presented one- and two-dimensional models with some assumptions such as constant porosity, non-volatile oil, and gas phase containing gas and vapor and insoluble in the oil. In this model, the convective terms, production and injection terms (the production and injection flow rates) are calculated in term of time, but condensation rate is expressed implicitly. Moreover, the gas phase temperature and composition are considered constant and equal to the previous time step. The energy equation is solved in the new time step. Finally, using the obtained pressure, temperature and fluid saturation, the equation of gas phase composition is solved. Another two-dimensional model has been presented in which, porosity is not considered constant and the effect of gravity is neglected in the Darcy equation. In addition, steam has been assumed as the only component of the gas phase [14]. A similar two-dimensional model is also presented in which, gravity was considered in Darcy equation and enthalpy was replaced with internal energy in the energy balance equation [15]. Coats et al. have presented series of studies [16–18] that finally lead to a developed model with three oil phases – light oil and gas, heavy oil and non-volatile part. In their model, relative permeability and capillary pressure were expressed implicitly.

According to the recent studies, it can be concluded that the model assumptions can be changed based on the reservoir properties. The results of some studies, [19,20] show that there is an optimum steam injection rate for a specified reservoir and matrix grid block size. Besides, oil production rate should be considered alone. Higher permeability can cause very high steam–oil ratio (SOR) which affect the economy of the process. It is obvious that the higher injection rate improves the oil recovery. However, SOR should also be considered at the same time. There is a trade-off between recovery and SOR [21]. Thus, in addition to modeling the