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Nonisothermal and Productivity Behavior of High Pressure Reservoirs

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Abstract

High pressure, low permeability reservoirs have been encountered in various parts of the world within the past few years. Commercial development of these reservoirs may require high drawdowns, possibly in excess of 6,000 psi. The impacts of drawdown in this range are: 1) increases in near wellbore temperatures due to Joule-Thomson expansion of the reservoir fluids and, 2) significant reductions in oil viscosity. The effects of large drawdown are evaluated with a transient, single-phase thermal simulator in which the oil viscosity is modeled as both temperature and pressure dependent and Joule-Thomson expansion of the reservoir fluids is considered. Results indicate near wellbore temperature increases of 4 to 24 ºF for drawdowns between 2,000 to 10,000 psia due to Joule-Thomson expansion of the reservoir oil and connate water. Furthermore, if oil viscosity is not modeled as pressure dependent productivity indices will be under predicted and analysis of well tests will result in estimated skin values lower than actual. Temperature profiles within the formation are presented for a range of rates and drawdowns. Additionally, a comparison of maximum wellbore temperatures and profiles between transient, steady state and macroscopic energy models is presented. Technical rationale is also presented to explain the transient heating or cooling phenomena which occur immediately after a rate change. Synthetic well tests are generated to illustrate the impact of high drawdown on well test interpretation. These tests show a region of improved mobility in the near wellbore region due to the reduction in the oil viscosity.

Introduction

Commercial production rates for deep, high pressure and low permeability reservoirs may require high drawdowns. This is particularly true if stimulation techniques such as hydraulic fracturing or acidizing are not feasible due to technical limitations, operational constraints or cost. Oil viscosity must be modeled as a function of pressure, and to a lesser extent temperature, for accurate productivity predictions and well test analysis. While the dependency of oil viscosity on pressure and temperature is well established (Bird et al. 2002), applications to drawdowns in the range of 6,000 to 10,000 psi have rarely been considered. The definition of drawdown considered in this study refers to the difference between the pressure at the reservoir outer radius and the wellbore flowing pressure. It does not refer to pressure gradients within the near wellbore region. Drawdowns of this magnitude constrained to the near wellbore region would certainly be catastrophic for either the completion equipment and/or the formation.

Joule-Thomson expansion thermal effects within a reservoir are rarely considered as drawdowns are generally not high enough for Joule-Thomson expansion effects to be significant. Most commonly, Joule-Thomson expansion effects are considered as part of wellbore and completion modeling where pressure drops can be considerable (Ouyang and Belanger, 2006). This includes flow within the wellbore, through perforations, liners and sand control equipment. An early study by Steffensen and Smith (1973) discussed Joule-Thomson heating in relation to water injection wells and Joule-Thomson cooling in relation to gas wells. Their objective was to improve the interpretation of temperature logs by accounting for the impact of Joule-Thomson expansion thermal effects on the measured temperatures. They developed a steady state model to predict the temperature change within the near wellbore region due to Joule-Thomson expansion but ignored the heat capacity of the formation. As part of a horizontal wellbore modeling study, Yoshioka et al. (2007) developed a transient, coupled reservoir and wellbore model to predict the temperature changes caused by water or gas entry into the wellbore. However, reservoir drawdowns investigated in this study were low, ranging from 100 to 500 psi, which are typical horizontal well operating conditions.