SPE 115946

Numerical Modeling of Pressure and Temperature Profiles Including Phase Transitions in Carbon Dioxide Wells

Lincoln Paterson, SPE, CO2CRC, CSIRO; Meng Lu, SPE, CSIRO; Luke D. Connell, SPE, CSIRO; and Jonathan Ennis-King, SPE, CO2CRC, CSIRO

This paper was prepared for presentation at the 2008 SPE Annual Technical Conference and Exhibition held in Denver, Colorado, USA, 21–24 September 2008.

Abstract

Geological storage of carbon dioxide will usually be at conditions above the critical temperature and pressure, so the carbon dioxide will exist as a single dense phase. However, conditions in the upper part of a carbon dioxide well with surface temperatures below the critical point of 31 C can lead to boiling and condensation in the well. The consequences of this are most apparent when flow rate changes, for example when a well is shut-in or if there is a well blowout.

We have calculated density profiles for wells experiencing different thermal conditions to determine how bottom-hole pressures are related to wellhead pressures. There are two limiting cases, one when the fluid is in thermal equilibrium with the rock at the same horizon, the other when there is no heat exchange with the casing or the rock. We find that in deeper wells static columns can exist in a stable state with liquid to the surface, but for shallower wells or wells in depleted reservoirs that a static column can be initially unstable with two-phase conditions near the surface.

In producing wells, as the flow rate increases from static conditions, the pressure and temperature at the wellhead increases until high production rates are reached when the wellhead temperature then decreases, which can be to very low values. For injection wells, bottom-hole conditions are confined between the wellhead and the reservoir temperature.

In general, phase change does not prevent carbon dioxide injection. Nevertheless care is needed in shallower or depleted reservoirs for the interpretation of reservoir pressure, the use of pressure for monitoring, and in all reservoirs for the management of blowouts.

Introduction

Carbon dioxide (CO_2) wells are used for both injection and production. Injection wells have been used in enhanced oil recovery (EOR) for many decades (Jarrell et al. 2002). CO_2 wells for production from underground natural accumulations have been used to provide a source of CO_2 for EOR and other industrial uses. Recently, however, interest in CO_2 wells has intensified as a result of investigation into geological storage as a means of reducing atmospheric greenhouse gases.

Accurate determination of downhole pressures is particularly important if pressure is being used to monitor the performance of a geological storage reservoir. Reliable knowledge of bottom hole pressure is also helpful in preventing injection above the pressures than can damage the formation (Kelly, 2006). While bottom-hole pressure can be measured using gauges, there is always the prospect that over a long period of time downhole gauges may fail. Hence it is convenient to be able to calculate downhole pressure from wellhead pressure. CO_2 has a critical pressure of 7.38 MPa [1071 psi] and critical temperature of 31.0 C, so if the fluid is near usual surface temperatures, conditions in the upper part of a well can cross the saturation line of CO_2 with boiling and condensation in the well if fluid pressures are in the vicinity of the critical pressure. Furthermore, near the saturation line of CO_2, fluid properties display severely nonlinear behavior that makes numerical simulation challenging. This parallels the situation in gas condensate wellbore modeling where retrograde condensation, liquid holdup and varying fluid composition make pressure drop calculations difficult (Sadegh et al 2006).

This issue of phase change is usually not of concern during injection of CO_2 for EOR, as EOR normally involves continuous columns of liquid to the surface because of the reservoir pressures required for minimum miscibility. For example, in the Denver Unit CO_2 flood, injection pressure is around 12.4 MPa (Fleming et al. 1992), far above the critical pressure at 7.38 MPa. As another example, measurements of pressure and temperature during EOR described by Kelly (2006) have surface pressures always above 8.6 MPa even though some of the wells have fluid temperatures at the surface around 27 C, hence below the critical temperature.