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Liquid loading in gas wells: Experimental investigation of back pressure effects on the near-wellbore reservoir

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A B S T R A C T

A large-scale core-flooding experimental setup was designed and constructed to investigate the back pressure effects on transient flow through porous medium, and so mimic the physical process of liquid loading and reservoir response. Between initial and final steady-state flowing conditions, where inlet pressure was maintained at a constant level while initiating a transient pressure build up at the core sample end, an "U-shaped" temporal distribution of pore fluid pressure within the medium itself was observed, which is in direct contrast to the conventional reservoir pressure profile.

1. Introduction

In recent decades, considerable research has been conducted on liquid loading and many well established approaches have been used to alleviate its effects on gas production. However, the current methods for modeling/predicting liquid loading have oversimplified the role of transient phenomena in the near-wellbore reservoir.

After the onset of liquid loading, accumulated liquids at the bottomhole will create a back pressure, at a given instant, to restrict gas flow from the near wellbore region. Once the hydraulic head is equal to the reservoir pressure, the gas flow in the wellbore will cease. Considering these subsequent transient phenomena, liquid loading is a dynamic issue that involves both wellbore and reservoir. This research focused on experimental and numerical investigations of back pressure effects on transient flow through the near-wellbore reservoir.

In this study, the concept of the U-shaped pressure profile along the near-wellbore region of a reservoir under transient flow conditions was experimentally and numerically reproduced for single-phase gas flow in large-scale tests for the first time.

1.1. Liquid loading

In theory, every gas well will experience liquid loading in the latter stages of its producing life, becoming incapable of carrying liquids associated with produced gas to the surface. This leads to an increasing back pressure due to a rising liquid column at the bottomhole, which initially decreases deliverability, then prevents gas flow from reservoir, and eventually kills the well (Falcone and Barbosa Jr., 2013).

To identify associated subsequent dynamic behaviors in liquid loading, such as liquids accumulation and fluids re-injection, the relevant loading evolution over time must be investigated. The liquids accumulation process in loaded gas wells begins with the gas flow rate being greater than its critical flow rate, so all liquids in the tubing can be lifted to the surface by a gas core under steady state conditions (Coleman et al., 1991). With reservoir pressure depletion, the actual gas flow rate in the wellbore becomes less than the critical flow rate, causing liquids to holdup at the bottomhole. Once the hydraulic back pressure due to a column of accumulated liquids balances the reservoir pressure, the well will be completely loaded and the gas flow will decrease to zero.

To better understand reservoir behaviors in liquid loading, Zhang et al. (2010) developed a transient near-wellbore reservoir simulator based on a numerical 1-D, two-phase system code using an IMPES method to implicitly solve for pressures and explicitly

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solve for phase saturations. The authors stated that a "U-shaped" pressure profile can be generated along the near-wellbore region by reason of the pressure variation in the wellbore (Fig. 1). When the bottomhole pressure oscillates, the reservoir pressure response is not instantaneous and can even be particularly slow in low permeability formations due to a combination of inertia and compressibility effects. The "U-shaped" pressure profile could also explain the re-injection of the heavier phase into the reservoir. The bottomhole pressure oscillations acted as a boundary condition in this modeling effort.

One of the key objectives of this study was to verify the concept of the U-shaped pressure profile experimentally and numerically. Initially, to avoid the complexity of two-phase flow, single gas was used as the test fluid in our study.

Wang (2012) and Liu (2016) experimentally verified the U-shaped pressure concept through a small-scale core-flooding facility with single-phase compressible flows. A Hassler cell, which could accommodate a core sample of 30 cm length and 2.58 cm diameter, was modified to mimic the effect of varying downhole pressure on gas flows in the near-wellbore region of a reservoir. Pressure sensors were attached along the sandstone core and recorded the U-shaped pressure distribution generated during the transient experiments. Additionally, Obernkirchener Sandstone was selected as the core raw material for the experiments. However, the small rock sample size and relatively low injection pressure (5 barg) may have limited the laboratory evaluation to a certain degree, so a novel large-scale core-flooding experimental setup is designed and constructed in this study, allowing tests to be performed at a greater working pressure.

1.2. Core-flooding experiments

The properties of reservoir rock and fluid are universally investigated by the core-flooding experiments in the laboratory, where an elastic rubber sleeve that contains a core sample is placed in a cylindrical cavity with open ends (referred to as a core holder). The ends of the rubber sleeve are fitted over end plugs, where solid contacts are setup between the faces of end plugs and ends of the core sample. The open ends of the core holder can be sealed by end caps with O-rings. During a core-flooding experiment, the rubber sleeve will be compressed by the pressurized fluid in the annular space surrounding it to provide radial overburden pressure on the core sample. Axial overburden pressure can also be added, depending on the type of the core holder. The tested fluid is forced into one end of the core sample through the end plug with an inlet pressure/temperature and emerges at the other end of the core sample with an outlet pressure/temperature.

2. Review of existing core-flooding research facilities in the public domain

This section presents some selected core-flooding experimental setups from published laboratory studies, focusing on setup purpose, tested phases, core dimensions, core holder types, rock properties, produced fluids' separation and corresponding working conditions. This extended literature review is a preparation for the design of the core-flooding apparatus in this study.

Different porous media are chosen based on various experimental purposes, including sandstone, limestone, sand mixture and glass beads (Table 1). Most popular is sandstones due to its qualified permeability and porosity. In some cases, composite cores were applied in tests to obtain a core sample with larger dimensions (Alvarado et al., 2001). Large scale samples were only apparent in tests with unconsolidated artificial porous medium. The maximum length of sample was a test cell of 83.82 cm, packed with a mixture of sand, oil and water (Rivero and Mamora, 2005); the maximum length/diameter ratio was 18.13, using various diameter glass beads as artificial porous medium (Jamialahmadi et al., 2005).

Differences between designed laboratory and actual reservoir conditions need to be compensated for. The inlet pressure of injected fluids was generally provided by fluids pumps or gas compressors; the largest being 300 bars (Darvish et al., 2006). Temperature was usually controlled via heating cables twined on the core holder. Alternatively, a temperature controllable compartment that could accommodate the entire holder was used; a maximum temperature of 160 °C was achieved for three-phase flow apparatus with an accuracy of ±0.1 °C (Ebeltoft et al., 1998).

Few core-flooding experimental setups in Table 1 are capable of measuring pressure distribution along the core sample, as this type of measurement can only be realized by the specially made core holder with pressure taps molded. Also, laboratory tests tend to be under steady state or unsteady state conditions; very few involve time as a factor in their experiments.

3. Design and construction of the experimental apparatus

3.1. Core sample preparation

One of the essential objectives of this study was to upscale the

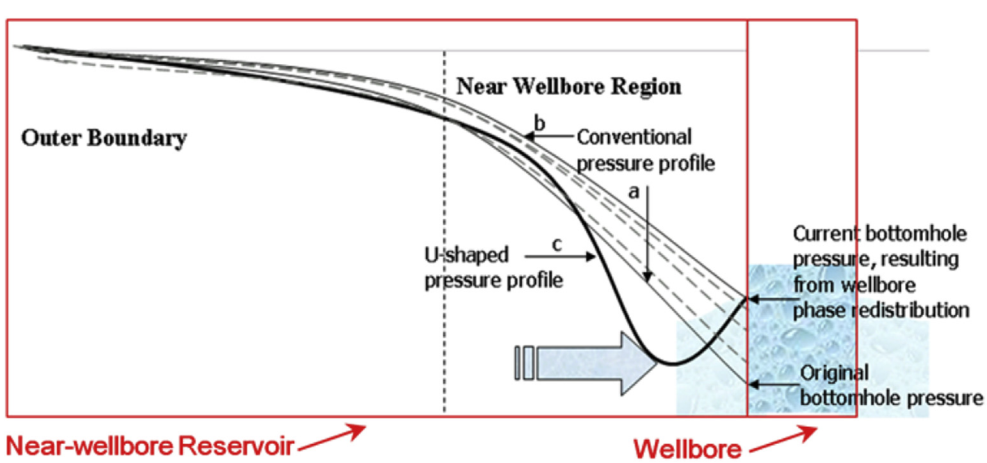

Fig. 1. Schematic of the "U-shaped" pressure profile generated by the transient reservoir simulator developed by Zhang et al. (2010).