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Optimizing production from water drive gas reservoirs based on desirability concept

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ABSTRACT

There are various factors which determine the optimization and economic production from water drive gas reservoirs. These factors play an important role in designing an effective reservoir development plan. The present study, in the first step, investigates the relation between recovery factor, volumetric sweep efficiency and cumulative water production with six different engineering and geologic factors using design of experiments (DOE) and response surface methodology (RSM). Next, all derived response functions are optimized simultaneously based on the concept of desirability. In this manner, part of water drive gas reservoirs is simulated using Box–Behnken design. Important factors that have been studied include reservoir horizontal permeability (K_h), permeability anisotropy (K_v/K_h), aquifer size (V_{aq}), gas production rate (Q_g), perforated thickness (H_p) and tubing head pressure (THP). The results indicate that by combining various levels of factors and considering relative importance of each response function, optimized conditions could be raised in order to maximizing recovery factor, volumetric sweep efficiency and minimizing cumulative water production. Also high rates of gas production result poor volumetric sweep efficiency and early water breakthrough, hence ultimate recovery factor decreases by 3.2–8.4%.

1. Introduction

Prediction of gas production is an important part of reservoir development, management and economic evaluation. Today, with the increasing growth of need to use of fossil fuels and the high volume of trapped gas in reservoir, it is crucial to optimize production from water drive gas reservoirs. Without investigating and understanding the production sensitivities to parameters such as gas production rate, tubing head pressure, perforated length from these reservoirs, it is not possible to reach predetermined goals to increase profitability and reduce costs. Considering that a large part of gas reserves are recovered using the water drive process, it is very important to understand the mechanisms affecting the production from these types of reservoirs. The experimental study of Geffen et al. (1952) on core plugs revealed that the trapped gas saturation varied from 15 to 50 percent of the pore space for various porous media. Agarwal (1965) demonstrated that the ultimate recovery factor is a function of production rate, residual gas saturation, aquifer permeability and volumetric sweep efficiency. Gas recovery factor increases with increasing production rate and decreasing aquifer permeability. Knapp et al. (1968) developed a two-phase two-dimensional model for predicting the gas recovery from aquifer storage fields as a function of production rate, aquifer strength and reservoir heterogeneity. Lutes et al. (1977) reported that the final blowdown of a Gulf Coast water drive gas reservoir at a reserves/production ratio of less than 2 provided an increase in gas recovery. Brinkman (1981) reported that accelerated gas withdrawals of up to 115 MMSCF/D from a U.S. gulf coast water drive gas reservoir resulted in a 20% increase in remaining gas recovery versus continued low-rate depletion. Al-Hashim (1998) studied the effect of aquifer size on partial water drive gas reservoirs. They concluded that if the ratio of aquifer external radius to reservoir external radius be less than two, the effect of aquifer on performance of the gas reservoir can be neglected. For ratios greater than two, gas recovery is sensitive to both initial reservoir pressure and aquifer size. Increasing aquifer size and initial reservoir pressure reduces gas recovery. A simulation study by Cohen (1989) determined that accelerating production rate and coproduction increases recovery by 2.3% and 5.6% respectively. A reservoir simulation study by Hower and Jones (1991) showed that to increase recovery, the production rate should be lowered rather than accelerated because of improved volumetric sweep efficiency. El-Ahmady et al. (2002) studied the effect of aquifer on estimation

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of the original gas in place. They showed that the unsteady state nature of aquifers can lead to overestimation of the original gas in place. Armenta and Wojtanowicz (2002), Armenta et al. (2003), Armenta and Wojtanowicz (2005) studied the effect of well completion on performance of gas wells. Sech et al. (2007) simulated the effect of production rate on recovery factor in horizontal wells. They found that recovery reduces by increasing the production rate and permeability anisotropy due to water cresting. Wang (2009) studied the impact of turbulence and the importance of hydraulic fracturing on well deliverability for both vertical and horizontal gas wells. Lee et al. (2010) presented a correlation for predicting recovery factor changes with aquifer size, ratio of residual to initial gas saturation, ultimate volumetric sweep efficiency, abandonment and average reservoir pressure. Wang (2012) studied the tubing limitation and turbulence effects on well deliverability of both vertical and horizontal wells with and without artificially induced hydraulic fractures. Sedaghatzadeh et al. (2013) investigated the optimum accelerating production rate from water drive gas reservoirs in laboratory scale systems. Rezaee et al. (2013) studied the effect of heterogeneity and aquifer to gas zone permeability on the gas phase trapping in water drive gas reservoir. Results of their study in laboratory scale show that heterogeneity is not always detrimental to gas recovery and it may be improved with increasing heterogeneity when ratio of aquifer to gas zone permeability is less than one. Review of previous studies shows that the simultaneous optimization of recovery factor, volumetric sweep efficiency and cumulative water production from water drive gas reservoirs has never been investigated. This objective is studied by applying design of experiments, response surface methodology and desirability concept. Experimental design and response surface methodology has been used in petroleum engineering applications including performance prediction (Chu, 1990), uncertainty modelling (Damsleth et al., 1991; Van Elk et al., 2000; Friedmann et al., 2001), sensitivity studies (White et al., 2000), upscaling (Narayanan et al., 1999), history matching (Anonsen et al., 1995) and development optimization (Dejean and Blanc, 1999). Also multiple response optimization based on desirability concept is widely used in numerous engineering fields (Harrington, 1965; Derringer and Suich, 1980). This study is one of the earliest ones taking advantages of design of experiments, response surface methodology and desirability concept for optimizing production from water drive gas reservoirs. Production optimization will be based on maximizing recovery factor and volumetric sweep efficiency and also minimizing cumulative water production.

2. Model description

The model described here simulates gas reservoirs with an active bottom aquifer using a radial system (Fig. 1). The reservoir zone measures 3300 feet in the radial direction and has a maximum gas column thickness of 300 feet. A bottom water aquifer is connected to the base of reservoir. The aquifer measures 6600 feet in the radial direction, extending beyond the reservoir. The aquifer thickness is not constant and changes in order to modify aquifer size during simulation. Flow is simulated using a gridding scheme that is locally refined around the well, and coarsened away from the well in the radial direction. The width of cells increases exponentially and highest resolution cells are located close to the well. Grid layering in the vertical direction is considered 120 layers, 100 layers with thickness of 300 feet for reservoir and 20 layers for aquifer section. The first 10 layers of the aquifer has constant thickness of 100 feet and the second 10 layers has a variable thickness to be able to set the ratio of aquifer to reservoir volume namely aquifer size. Reservoir and aquifer porosity is constant in all simulation and it

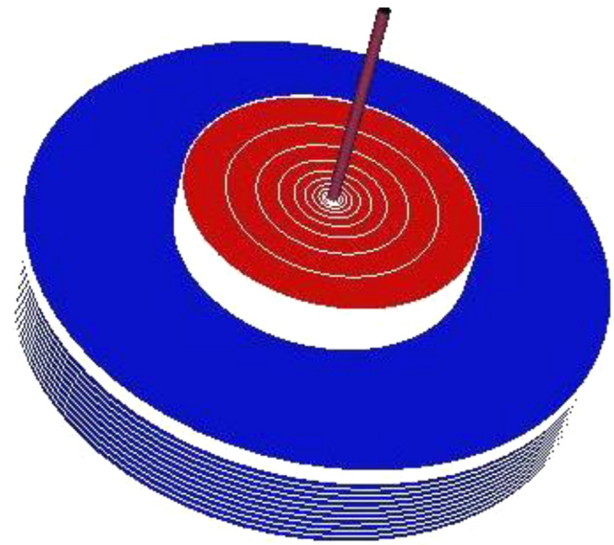

Fig. 1. Simulated model. The reservoir is shown in red with 3300 ft external radius, and the aquifer in blue with 6600 ft. The reservoir has 100 layers with constant thickness of 300 ft and the aquifer with 20 layers of variable thickness. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

was set to 25%. The reservoir temperature and initial reservoir pressure at datum depth of 8530 feet were fixed to 220 °F and 5290 psi, respectively. The gas viscosity was estimated using the correlation developed by Lee et al. (1966). The gas deviation factor was estimated using correlations presented by Dranchuk et al. (1974). Relative permeability and capillary pressure data measured for gas–water systems in the experimental work of Chierici et al. (1963) has been used in this survey. Production is via a single vertical well with 7 inch internal – tubing diameter. Reservoir horizontal permeability, permeability anisotropy, aquifer size, gas production rate, perforated thickness and tubing head pressure are varied simultaneously in simulation tests that are described in the following section. In this study, the well produces at constant tubing head pressure until production rate is greater than 10% of maximum initial gas production rate and bottom hole pressure is more than 500 psi. The Petalas and Aziz (2000) mechanistic model has been used to calculate vertical flow performance curves. This model is very accurate and it can be used for up and downhill flow, and for all pipe geometries.

3. Methodology

3.1. Determination of the response functions

The following study, inspect the effect of six engineering and geologic factors on gas recovery factor, volumetric sweep efficiency and cumulative water production. In this regard, design of experiment and response surface methodology was employed. Design of experiments (DOE) is a well known technique to get maximum information with simultaneous varying of all parameters and required less number of performing time consuming numerical tests. Response surface methodology (RSM) explores the relationships between several explanatory variables and one or more response variables to obtain an optimal response. More details about design of experiments and response surface methodology are given in Box and Wilson (1951). Based on Box–Behnken Design (1960), it is required to design and simulate 49 different models to extract necessary information such as reservoir pressure,