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Well performance optimization for gas lift operation in a heterogeneous reservoir by fine zonation and different well type integration

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ABSTRACT

In this study, an integrated optimization procedure was proposed for well performance analysis in a heterogeneous oil field from southwest Iran. Proposed integrated strategy optimizes well performance in an iterative manner, while fluid properties, geological and petrophysical data were analyzed separately by new advanced methods. Subsequently, integrated solution was introduced by integrating various well types geometry and fine zonation of the target formation. Combination between each zone and each well type was based on three potential oil bearing zones predefined by well log data analysis. Target formation, the Sarvak formation limestone, was divided into 10 different zones and much more subzones according to the geological and petrophysical data. Afterwards, 17 wells with various geometries were modeled in the upscaled reservoir model. Fluid properties and reservoir characteristics were also obtained and analyzed from different samples taken from target formation. Results of applying the proposed integration strategy defined that the maximum production rate occurs while water cut does not exceed 10%. Performed analysis also suggest 15 MPa as the optimal value of the surface gas lift pressure and state that the gas oil ratio should not exceed this ratio at the flowing wells bottom condition. Sensitivity analysis on tube size expresses 4.67-inches tube as the optimum value. Meanwhile, sensitivity analysis on flow rate represents that optimal value of this parameter shows high sensitivity to changes in production index. Results showed that 7% change in production index will make 4% changes in optimal gas flow rate value.

1. Introduction

Total oil production from hydrocarbon reservoir greatly depends on well locations, petrophysical properties of the reservoir rock, geological properties of the reservoir, well performance condition and other operational parameters. Among these parameters, well geometry and well-pattern design have critical importance on hydrocarbon field development (Onwunalu and Durlofsky, 2011). Shadizadeh and Zoveidavianpoor (2009) stated that optimized production rate is a pursued goal which could be achieved only through well pattern and well performance optimization. Yang et al. (2016) stated that well placement optimization has less effect on homogenous and simple structure oil reservoir. However, considerable difference on the final profits would be observed in heterogeneous and anisotropic reservoir after well pattern and well performance optimization (Soleimani et al., 2016). Delalat and Kharrat (2013) stated that homogeneity of porous media has highest efficiency in production (namely 40%), while in heterogeneous media it decreases to 37%. The practical approach for incorporating impact of the reservoir heterogeneity in production scenario entails numerous (objective) function evaluations, each requiring a full set of reservoir simulation run (Balouchi et al., 2013; Nozohour-leilabady and Fazelabdolabad, 2015).

During application of advanced methods in petroleum engineering, early optimization studies on inflow performance relationship (IPR) featured simple reservoir models and linear programming techniques (Gharbi and Mansoori, 2005). Guo (2001) proposed pay zone thickness, reservoir rock permeability, fluid viscosity, wellbore radius, drainage area and skin factor as effectual parameters in IPR predication model, when bottom hole pressure data are not available. Hagoort (2007) studied vertical array of perforations for IPR prediction in production wells. This model was later modified by Lu and Tiab (2008), which presented steady state

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and pseudo-steady state productivity equations for an off-center partially penetrating vertical well in an anisotropic reservoir. Lu and Tiab (2011) also presented pseudo-steady-state productivity formula for a partially penetrating vertical well in a box-shaped reservoir. Bahadori et al. (2013) developed a simple-to-use equation for the oil flow rate prediction as a function of dimensionless length and ratio of horizontal displacement well length over drainage area side for various drainage areas. Ahmadi et al. (2015) developed a least square support vector machine (LSSVM) model for predicting pseudo skin factor of horizontal wells in the rectangular drainage area using artificial neural network (ANN) with linked to the particle swarm optimization (PSO). Tabatabaei and Zhu (2010) considered three different boundary conditions for analytical IPR prediction in horizontal wells. These boundary conditions were constant boundary pressure (steady-state flow condition), no-flow boundary (pseudo-steady-state flow) condition and infinite acting reservoir (transient flow) condition. The study of Tabatabaei and Zhu (2010) was complete in case of using various types of equation of states and boundary conditions. Due to the similarity of the reservoir in this study (this similarity refers to the fluid property, reservoir rock property and reservoir petrophysical characteristics) with the conditions of what were presented by Tabatabaei and Zhu (2010), their strategy was used here for IPR prediction.

However, production optimization process requires understanding of the actual characteristics of the reservoir (Soleimani and Jodeiri-Shokri, 2015). These characteristics consist of reservoir petrophysical properties, average reservoir pressure, drainage data, skin factor, bottom hole flow pressure and well head pressure. Several methods were introduced to use these data for well performance optimization which evolutionary strategies are currently the most popular methods. Sarma and Chen (2008) listed various methods for well system analysis with different algorithms like as stochastic directions, pattern searches, direct searches as well as derivative methods like as finite differences or adjoint gradient estimation methods. Nozohour-leilabady and Fazelabdolabad (2015) have drawn acceptable result by application the Artificial Bee Colony (ABC) algorithm in their study. Due to the similarity of the study reservoir in this research with what was studied by Nozohour-leilabady and Fazelabdolabad (2015), therefore the ABC algorithm was selected here for optimizing production.

To perform natural flow analysis and optimization, porosity and permeability values must be upscaled from the measurement scale to the grid-block scale. There exist numerous methods for upscaling porosity and permeability values (Wu et al., 2002; Rekdal, 2009; Chen, 2009; Sharifi and Kelkar, 2013; Noorbakhsh et al., 2014). Iliev and Rybak (2008) introduced a simple numerical upscaling approach by solving multiscale elliptic problems. The main components of their method are: i) local solution of auxiliary problems in grid blocks and formal upscaling of obtained results for building a coarse scale equation; ii) global solution of the upscaled coarse scale equation; and iii) reconstruction of a fine scale solution by solving local block problems on a dual coarse grid.

In this study, we used the numerical method of Iliev and Rybak (2008) for porosity and permeability upscaling. Afterwards natural fluid flow analysis could be performed by different geometry of production wells. However, it should be noted that various bottom hole conditions and different tubing size of each production well in a gas lifted oil field would cause the gas lift performance differ for each individual well. In other words, the productivity index (PI) for each tubing size may differ while each size may produce different amount of oil for equal amount of gas injected into them. Therefore, it is required to perform a sensitivity analysis for different tubing size. Due to high accuracy of nonlinear dynamic model presented by Sharma and Glemmestad (2013), this method was used for sensitivity analysis here in this study.

Yet, all the required steps and information were performed and prepared to pave the way for well performance analysis by an integration approach. In this study, we proposed an integrated strategy to resolve ambiguities and well performance analysis of a heterogeneous reservoir from southwest Iran. Hence, since the main concern was to study optimization of the well performance in a heterogeneous reservoir, and we should seek to methodologies that could handle heterogeneity of the media, we proposed an integrated solution by combining two strategies of using different well types in box shaped reservoir model combined by thin reservoir zonation. Thus specific method of well performance analysis in heterogeneous reservoir was performed in the first step, followed by well system analysis. This integration procedure was used to develop inflow and tubing performance curves from results of a multiphase flow simulator. Pressure drop, fluid properties and related changes in well column, inflow and tubing performance curve were also evaluated with proposing separate productivity equation for different well types. Subsequently, performance prediction for the study reservoir was accomplished succeeded by final natural flow analysis.

It should be again emphasized that due many advantages of the equation introduced by Lu and Tiab (2008), their equation was selected for this study. They have derived an equation for box shaped reservoir model, which is appropriate model for fine zonation of the study reservoir. They have also showed that the off-center of the production well could be ignored and also the equation could be applied perfectly for partially penetrated well, which is the case that we would have in fine zonation approach.

The study of Tabatabaei and Zhu (2010) was complete in case of using various types of equation of states and boundary conditions. They have considered three different boundary conditions for analytical IPR prediction in horizontal wells. These boundary conditions were constant boundary pressure (steady-state flow condition), no-flow boundary (pseudo-steady-state flow) condition and infinite acting reservoir (transient flow) condition. Besides that, due to the similarity of our well geometry and well conditions, we decided to use their equation for horizontal wells IPR analysis. This similarity refers to the fluid property, reservoir rock property and reservoir petrophysical characteristics. The conditions of Tabatabaei and Zhu (2010) for horizontal wells are in accordance with the conditions of Lu and Tiab (2008) for vertical wells, which makes ease use of the integration procedure.

2. Integrated strategy proposed in this study

Tabatabaei and Zhu (2010) derived various productivity equations with different boundary conditions for partially penetrating vertical well. Since various types of production wells are going to be combined with fine zonation in this study, equations derived by Lu and Tiab (2008); Tabatabaei and Zhu (2010) and Bahadori et al. (2013) were used for wells shown in Fig. 1. For bilateral well type, we used equation of Bahadori et al. (2013):

$$J_h = \frac{q_0}{\overline{P}_R - P_{wf}} = \frac{k_h}{141.2\beta_0\mu_0}\left(\frac{1}{\ln\left(\frac{r'_e}{r_w}\right) - A' + S_f + S_m + S_{CA,h} - C' + Dq_0}\right), \tag{1}$$