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Production Enhancement of an Oil Field using Integrated Modeling and Optimal Control

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INTRODUCTION

Usually, as the oil production continues, the reservoir pressure declines and the oil production rate falls below the economical rate. In these cases, one way to increase the oil rate is using artificial lift methods and one of the most common methods is gas lift [1]. Instability phenomenon sometimes observed in gas lift operation and causes periodically stopping production and vibrations that damage downhole and surface facilities [2]. During the artificial gas lift process, reservoir, wells, and surface equipment conditions are continuously changing. Therefore, gas lift operation must be monitored and injection conditions have to be updated with respect to the condition variation in order to obtain the optimum production rate and predict the performance of a hydrocarbon field [3]. In most gas lift projects, there is usually a limited amount of lift gas that should be allocated between different wells. Each well response differently to the injected gas and its production increment would be different based on its properties. Finding an allocation that maximizes the total oil production or maximizes the cashflow and prevents instability is an important issue.

METHODOLOGY

In the current study, Eclipse was used to simulate reservoir. Table 1 shows the properties of the simulated reservoir. Then, wells and surface flow pipeline network were modeled using Prosper. Eventually, MATLAB was used for connecting reservoir, wells and flow pipeline network to create an integrated model and allocate optimized lift gas rate among wells, by genetic algorithm.

Injection gas was allocated among wells according to different scenarios. These scenarios were included (1) natural reservoir production without using gas lift method (2) equal allocation of injection gas between producing wells (3) optimal allocation of injection gas without instability consideration, and (4) optimal allocation of injection gas with instability consideration as a constraint. The cashflow is considered as an objective function. The objective function and constraints in this current study are as follow:

$$\sum_{i=1}^{6} Q_{Oi} = f\,(q_{g_{injection}}) \quad (1)$$

$$Cashflows = \sum_{i=1}^{6} (Q_{O_i} \times P_O) + (Q_{G_i} \times P_G) - (Q_{W_i} \times P_W) \quad (2)$$

$$\sum_{i=1}^{6} q_{g_i} \le 12MMscf \quad (3)$$

$$q_{g_{i,\min}} \le q_{g_i} \le q_{g_{i,\max}} \quad (4)$$

RESULTS AND DISCUSSION

The production of the reservoir was begun in 2001 and continues until 2017. Then the production continued for 20-timesteps in the form of an integrated production model. In the first scenario, the oil production rate and cashflow are severely reduced due to increased water cut. Cumulative oil production increased 73652 barrel during the second scenario in comparison with the first scenario. Moreover, reduction of average fluids density and hydrostatic pressure drop in wells are the reasons of production improvement. Using the integrated production model with the optimal control system in gas lift process without considering instability as a constraint in the third scenario, improves cumulative oil production by 101% over the second scenario. The cumulative oil production in this scenario is 386786 barrels. Considering instability as a constraint in an optimal control system of integrated production model reduces cumulative oil production by 11293 barrels in comparison with the previous scenario. Also, during the fourth scenario, oil production rate fluctuations were eliminated. Comparison of Cashflow from different scenarios in each time step is shown in Figure 1.

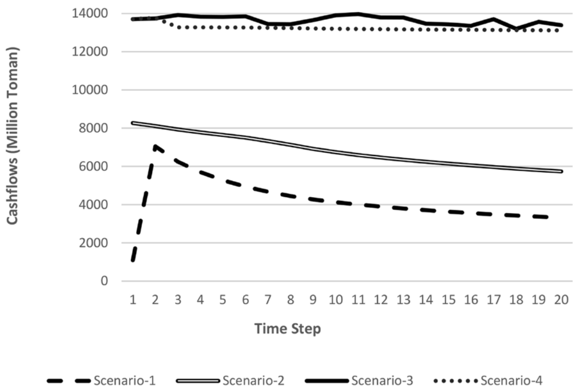

Figure 1: Comparison cashflow for different scenarios.

CONCLUSIONS

Using the integrated production model as a dynamic system for allocating injection gas among wells improves the prediction of an oil field performance because it considers parameters change over time. Results showed that using the artificial gas lift in the studied case had operational justification according to the condition of reservoir parameters such as bottomhole pressure, gas oil ratio and water cut. According to the results, using the integrated production model with the optimal control system in an artificial gas lift process improves cashflow by 224.86% over natural production condition in a hydrocarbon reservoir. Also, the amount of production loss that considering stability causes is very small, thus considering the stability as a constraint for the optimizer is a good way for escaping unstable flow.

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