WATER ALTERNATING GAS INJECTION FOR ENHANCED OIL RECOVERY IN THE PHITSANULOK BASIN

Suphattra Jaturakhanawanit* and Akkhapun Wannakomol

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Abstract

There are many methods that can be applied to increase recovery from hydrocarbon reservoirs. Water alternating gas injection (WAG) is one of them, which combines the advantages of the waterflooding and gas injection methods. Repetition of the WAG process can further improve the sweep efficiency on a micro scale. In this study, application of WAG was studied for conditions of an oil field in the Phitsanulok Basin by reservoir simulation using Eclipse 300. The sandbox model with both a production and an injection well is set up at 5 MMSTB. The miscibility flood is also set up for the WAG reservoir simulation setting. The reservoir was set the bottom hole pressure of production above 2165 psia for hydraulic pressure and 90% water cut as limitation in producing period. Results from the simulation testing indicate that the cumulative oil production was 3.35 MMSTB (4.44 MMRB) at the end of production.

Keywords: Water alternating gas injection, computer reservoir simulation, Phitsanulok Basin, optimized technical parameters

Introduction

Water alternating gas injection (WAG) is one of the most popular methods for enhanced oil recovery. Injected gas can occupy parts of the pore space being occupied by oil, and can reduce the viscosity of the remaining oil to make it more mobile. Water is injected subsequently to displace the remaining oil and gas. Repetition of the WAG process can further improve the recovery of the remaining oil in the reservoir (Tehrani, *et al.*, 2001). The Phitsanulok Basin is an appropriate choice to apply the WAG process for 2 reasons. First, the waterflooding method has been applied successfully in this oil field since 1980 (Rattanapranudej, 2004). Second, there is enough free gas and ground water for injection in this oil field (Chumkratoke, 2004). The objectives of this study are (1) to determine the appropriate operational program of the study field and, (2) to estimate the recovery efficiency of the WAG method. In this study the reservoir simulation Eclipse_300 software is used for these purposes. Reservoir simulation is a powerful and inexpensive tool which can predict what is going on in the

School of Geotechnology, Institute of Engineering, Suranaree University of Technology, 111 University Avenue, Muang District, Nakhon Ratchasima 30000, Thailand. E-mail: suphattra.ja@gmail.com
** Corresponding author*

reservoir and the amount of production from alternative operations.

Materials and Methods

Materials

Reservoir Simulation Input Data

The input data for each model were collected and obtained from a review of concessionaire results, laboratory measurement, and assumptions. The required data for the simulation comprise the reservoir, and rock and fluid properties as presented in Tables 1 and 2, respectively (Yaemphiphat, 2009). The other necessary data for WAG come from relative permeability which has a direct effect on the WAG process. It is shown in Figures 1, 2, and 3 for gas, oil, and water, respectively. A set of the composition of the injected fluid and reservoir fluid is also needed, as shown in Table 3. The mole fractions of the gas injection are from the separator. The properties of the fluid used in the equation of state are shown in Tables 4 and 5. Binary interaction coefficients are generated from PVT, which is a subprogram of Eclipse, by inputting the fluid properties in the reservoir. The PVT tables of oil and gas were calculated from the built-in software of the Eclipse Office software.

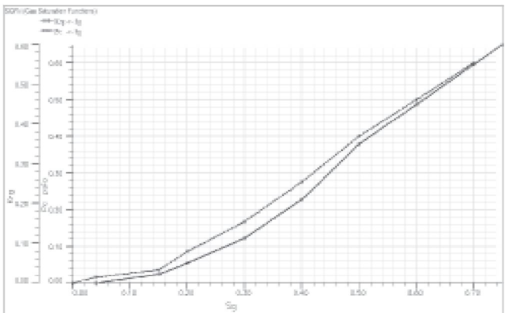

Figure 1. Relative permeability to gas

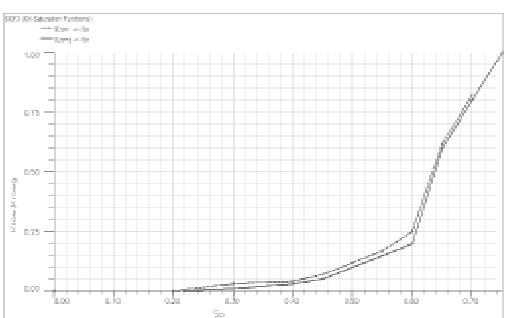

Figure 2. Relative permeability to oil

Sensitivity Analysis

The sensitivity analysis was to compare the recovery efficiency by varying parameters, to observe, and to analyse as follows:

a) Rate of Production and Injection Wells

The case will vary the production and injection rates by starting the injection at the first

Table 1. Reservoir properties

Properties	
Initial reservoir pressure	3000 psia
Bubble point pressure	1800 psia
Depth Oil-Water contact	5000 ft
Thickness	44 ft
Formation temperature	203°F
Pressure gradient	0.7 psi/ft

Table 2. Rock and fluid properties

Properties	
Rock type	Consolidated Sandstone
Porosity	0.2225 - 0.2325
Permeability	105.439 - 195.434 md
Vertical relative permeability = 0.1 ratio of Horizontal relative permeability	
Properties	
Oil gravity	39.4 API
Gas gravity	0.8 (SG Air = 1)
Densities of water	62.43 lb/ft^3
Water compressibility @ 3500 psi	3.08 x 106/psi
Viscosity of water	0.296 cp
Salinity	0 (fraction)
Surface condition	
Standard temperature	60°F
Standard pressure	14.7 psia

year of production. The results will be compared with the recovery factor under the limitations. The reservoir pressure is not constant during the WAG process and the formation volume factor of oil and gas is a strong function of the reservoir pressure. Control of the injection rate at the surface is impossible. For the injection well, water and gas are injected at the same fluid rate alternately and controlled by the downhole rate.

b) Slug Size

The ratio of water injection alternated to gas is 1. Cycles of alternated injection are 1 to 15 months.

Methods

Reservoir Simulation

Reservoir simulation, or modeling, is one of the most powerful techniques currently available to the reservoir engineer. Modeling requires a computer, because there are large amounts of data compared with most other reservoir calculations. Basically, the model requires that the field under study be described by a grid system, usually referred to as cells or gridblocks. Each cell must be assigned reservoir properties to describe the reservoir.

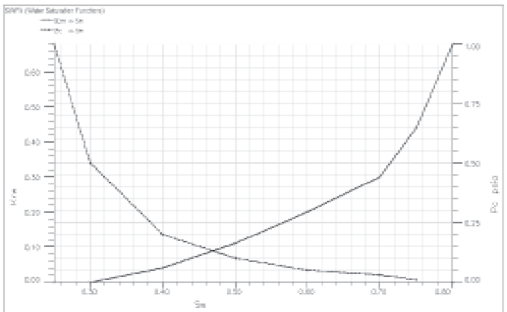

Figure 3. Relative permeability to water

Table 3. Composition of fluid

Composition	Mole fraction of reservoir fluid
C1	0.50
C2	0.04
C3	0.02
C4	0.01
C5	0.01
C6	0.03
C7+	0.39

Table 4. Fluid properties of composition in reservoir

Composition	Pc (Psia)	Tc (R)	MW	Acentric factor	Critical Z
C1	666.40	343.33	16.04	0.0104	0.2902
C2	706.50	549.92	30.07	0.0979	0.2830
C3	616.00	666.06	44.10	0.1522	0.2785
C4	550.60	765.62	58.12	0.1852	0.2756
C5	488.60	845.80	72.15	0.1995	0.2744
C6	436.90	913.60	86.18	0.2280	0.2719
C7+	285.00	1287.00	215.00	0.5200	0.2451

Table 5. Composition of fluid

Composition	C1	C2	C3	C4	C5	C6	C7+
C1	0	0	0	0	0	0.029	0.049
C2	0	0	0	0	0	0.010	0.010
C3	0	0	0	0	0	0.010	0.010
C4	0	0	0	0	0	0	0
C5	0	0	0	0	0	0	0
C6	0.029	0.010	0.010	0	0	0	0
C7+	0.049	0.010	0.010	0	0	0	0

Compositional Model

The components in the reservoir are calculated individually (methane, ethane, propane etc.). In a reservoir containing light oil, the hydrocarbon composition as well as the pressure affects the fluid properties. The equilibrium flash calculation using K values and equation of state must be used to determine the hydrocarbon phase compositions. In a compositional model, we in principle make mass balance for each hydrocarbon component, such as methane, ethane, propane etc. In practice, we limit the number of components included and group components into pseudo-components (Elizabeth, 2005).

The size of the reservoir simulation model of 5 MMSTB oil in place was developed by utilizing "Eclipse Office" software. This model has been constructed in sandbox geometry. The grid blocks are 25x25x5 in the x-, y-, and z-directions, and active in all cells. The created reservoir model dimensions are 87.5 ft in the x- and y-directions, and 8.8 ft in the z-direction. The boundary effect was concerned to the reservoir model. The well pressures will overestimate when the well gets very close to the boundary (in this case, less than 50 ft) (Shu, 2005). The production and injection wells are located at the x-y coordinates 5, 12 and 20, 12 respectively. The depth of the top of the reservoir is 4956 ft below the surface datum. The geometry of the model is shown in Figure 4. For the production well, the minimum bottom hole pressure was set to 2165 psia, in order to prevent the reservoir pressure dropping to below the hydraulic pressure. The 50 STB/D minimum oil production rate and the 90% water cut are 2 economic limits to be specified for the production well. When one or both is reached, the well will be shut down. Both the injection and production wells are controlled by the same downhole rate.

Results and Discussions

All results of simulations are presented in Table 6. The production and injection pattern for each case resulted from trial and error to obtain the optimum recovery.

The production and injection rates were maintained at the rate of 700 RB/D. There is a switching injection between 12 months of water and 1 month of gas. After running the program, the result is a 10-year plateau production and the final rate is 270 RB/D (Figure 5). The cumulative oil production is 4.44 million reservoir barrels at the end of the 20th year of production with recovery of 65.13% of the original oil in place (Figure 6). The reservoir pressure slightly fluctuated in the range of 2980 to 3020 psia due to the alternation of fluid injection. The reservoir pressure had been increased when the water was injected, and had been decreased when the gas was injected (Figure 7). In comparison with 13 months' water and 1 month's gas injection, the case yields the highest recovery but the bottom hole pressure of the injection well is higher than the fracture

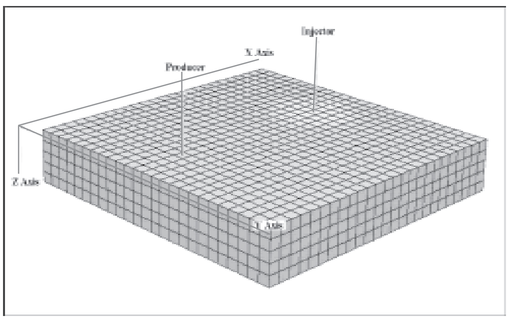

Figure 4. Geometry of reservoir model and well locations

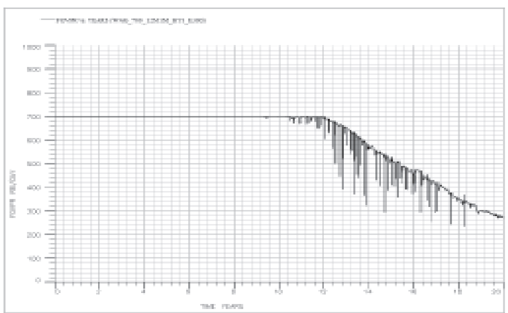

Figure 5. Oil production rate vs. Time plot of 700 RB/D

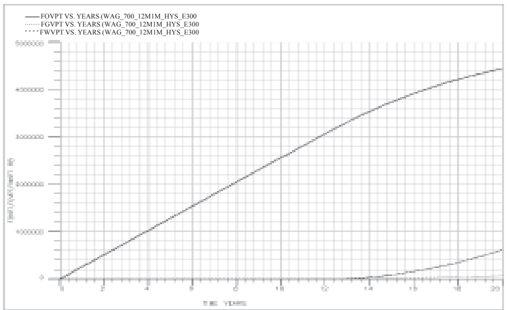

Figure 6. Cumulative fluid production vs. Time plot of 700 RB/D

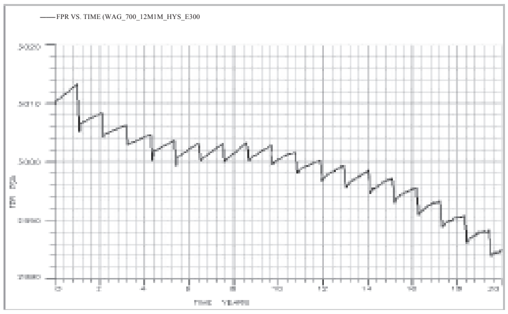

Figure 7. Pressure of reservoir vs. Time plot of 700 RB/D

Table 6. Recovery factor

Production rate, RB/D	Injection rate, RB/D	Water period, months	Gas period, months	RF, %	BHP $(max)_i$, psi
700	700	11	1	64.95	3483
700	700	12	1	65.13	3498
700	700	13	1	65.26	3520
800	800	10	1	68.57	3570
800	800	12	1	68.63	3576

pressure limit. At the same condition, although maintaining the oil production rate at 800 RB/D recovers more than at the rate of 700RB/D for the same 12 months' water and 1 month's gas injection, the bottom hole pressure of the injection well reaches the fracture pressure (Table 6).

The high injection rate yields more oil recovery, because of a more sweeping volume of the displacement, but it is not always the appropriate condition if the water cut is too high or the bottom hole pressure is greater than the fracture pressure. Also, control of the gas is necessary in order to prevent the gas fingering effect that reduces the recovery. Moreover, the excessive water rate causes early water breakthrough.

Conclusions

Reservoir simulation is a powerful and flexible tool to predict reservoir performance in many operational designs. The most suitable condition for individual projects can be achieved by performing reservoir simulation with the WAG method. The WAG method achieves the optimized recovery of 65.13% of the original oil in place at 700 RB/D with 1 month's gas injection and 12 months' water injection. Use of trial and error to get the best fit for individual projects is needed.

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