Critical Parameters Affecting Water Alternating Gas (WAG) Injection in an Iranian Fractured Reservoir

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ABSTRACT

Microscopic oil displacement of water flooding and sweep efficiency of continuous gas injection could be improved by water alternating gas (WAG) injection. The WAG injection process aims to squeeze more oil out of the reservoirs; in this method, water and gas are alternatively injected into the reservoir. Also, availability of hydrocarbon or CO_2 gases in the field makes it attractive for gas-based enhanced oil recovery (EOR) methods such as water alternating gas (WAG) injection. Conducting some simulations are required to optimize EOR methods for investigating the effect of parameters affecting WAG injection. Reducing and controlling the mobility ratio, creating stable front, and preventing early fingering of gas are the advantages of water alternating gas injection, which have promoted extensive applications throughout the world. Critical parameters, including WAG ratio, injection rates, gas composition variation, cycle times and some others which affect the WAG injection as an enhanced oil recovery method are studied thoroughly in this paper. Because of higher mobility of water relative to gas, injected water has more efficiency, but the excess use of water will cause early breakthrough. This study suggests that injecting proper volume at suitable times with different rates during injection time provides a 10 -15 % improvement in the recovery factor for one pore volume which is injected by using commercial reservoir simulator ECLIPSE 300. The best rate variation during a cycle time of WAG injection and choosing of first injection phase are discussed in this paper.

Keywords: Water Alternating Gas (WAG), Simulation, Mobility Ratio, WAG Ratio, Enhanced Oil Recovery (EOR), Permeability

INTRODUCTION

WAG process is one of the enhanced oil recovery methods that has the advantage of increasing microscopic efficiency by using a miscible displacement, while it is maintaining a good macroscopic efficiency by using alternating water. Many successful results have been reported in this EOR process, and it is widely used in the North Sea [1]. An increasing demand for energy has forced oil companies to think about secondary and tertiary oil recovery methods to increase the recovery from the existing reservoirs [2]. To increase the extent of

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Article history
Received: May 07, 2015
Received in revised form: September 21, 2015
Accepted: September 26, 2015
Available online: July 22, 2017

the reservoir contact by the injected gas, it must be injected alternatively with water. This mode of injection is called water alternating gas (WAG) it's the popularity of which has been increasing since 1950 [3]. This method is being widely practiced in the oil fields, e.g. in Gulfaks fields [4]. This EOR method also has been used in gas/condensate reservoirs [5]. Microscopic oil displacement of water flooding and consequently the sweep efficiency of continuous gas injection could be improved by water alternating gas injection. About 55% of the total oil productions by enhanced oil recovery (EOR) methods in the United States are resulted from gas-injection methods, most of which are WAG processes [6]. The WAG process improves the macroscopic and microscopic sweep efficiency of water and gas injection process at the same time. The cyclic nature of the WAG process causes (1) an increase in water saturation during the water injection half cycle and (2) a decrease in water saturation during the gas injection half cycle. This process of inducing cycles of imbibition and drainage causes the residual oil saturation to be typically lower than that of water flooding and similar to those of gas flooding. The key parameter, which could lead to frontal instability and by passing of oil by injection fluids are the heterogeneity of reservoir and the mobility ratio of the fluids. Gravity segregation is another factor that impacts the recovery [6]. The injected volume for each phase is an important factor to achieve a good sweep efficiency and economical process. Another important parameter is the composition of the injected fluid and its effect on model to predict the process so that operating strategy design can be performed [7]. Continuous slug injection performs better than WAG when the largest permeability layers are at the bottom of the aquifer, richer gases are used, and the vertical to horizontal permeability ratio is small [8]. Christensen et al. presented an extensive review of 59 field cases [9, 10]. WAG injection is used with immiscible and miscible gases [11, 12].

In this process, if the reservoir rock is water-wet, water fills the small pore spaces due to their high capillary pressure, and gas acts in an opposite fashion, which means that it goes through the larger pores. This shows that, in this process, gas acts as a complementary factor for the water flooding [13]. The WAG displacement will be optimized if the mobility ratio is favorable (less than 1). Increasing the viscosity of the gas or reducing the relative permeability of the gas can result in a reduction of the mobility ratio. The reduced mobility of the gas phase can be achieved by injecting water and gas alternately. It is important to adjust the amount of water and gas so that the best possible displacement efficiency will be achieved [14]. Too much water will result in poor microscopic displacement, and too much gas will result in poor vertical and maybe also horizontal sweep [15].

Layered reservoirs may represent favorable geological conditions for gas injection. For instance, if a high permeability layer is situated below a low permeability layer, it prevents quick gravity-segregated tonguing in the top zone towards the production intervals. The low vertical permeability of the layers also contributes to a better WAG sweep-out [16]. Furthermore, the studies indicate that the improved recovery by WAG method over regular water flood is possible mainly because of the trapped gas effect and better conformance. WAG flooding is a successful method for improving oil recovery. More than 80% of the WAG-flooded projects in the world have been reported profitable [17]. In recent decades, approximately 40% of big gas injection projects all over the world such as Canada, Russia, Turkey, and Norway have been performed as WAG [18]. Based on the results of an Iranian study on an Asmari reservoir portion of Mansoori oil field, it was shown that the WAG process can be optimized in order to have more efficiency than either water or gas injection. In addition, lower costs and the production conditions are kept in more desirable conditions [19].

Kharrat et al. in 2010 studied the parametric investigation of WAG injection process in naturally fractured reservoirs in Iran, and they concluded that by the optimization of significant parameters in WAG injection process more enhanced oil recovery can be expected than either water or gas injection alone [20].

Jafari et al. in 2008 conduct a series of experiments with the numerical simulation of different EOR techniques in a non-fractured carbonate core from an Iranian offshore oil reservoir. The results showed that the implementation of the WAG process at an optimal injection volume, optimum rate of injection fluids, and optimum WAG ratio can lead to a higher oil recovery in comparison with the other alternating scenarios such as gas injection and water injection [21].

The main purpose of this work is an investigation of the effect of parameters affecting WAG injection, and consequently the optimization of the crucial parameters of WAG process. In this study, the simulation studies are run on a synthetic model with real PVT data of the reservoir fluid in order to perform a qualitative study of the parameters which are crucial for a WAG process design by using a commercial reservoir simulator ECLIPSE 300. Firstly, a synthetic model was simulated, and then reservoir fluid was simulated by using the real PVT data. As the main procedure of this paper, 8 critical parameters affecting the incremental oil recovery, namely injected gas variation, cycle time of injection, first phase to inject, WAG ratio, water rate, gas rate, best period, and time of injection were investigated. The oil recovery was considered as the main indicator for choosing the optimized scenario.

FIELD DESCRIPTION

The investigated oil reservoir in this paper is located in an Iranian central oil field. For a better evaluation of the effect of several parameters, it is better to use a synthetic geological model. This synthetic model has a length of 2000 ft., a width of 1000 ft., and a thickness of 150 ft. The real model fluid and rock data and reservoir initial conditions were used. The oil was light oil with a gravity of 35° API and an oil formation volume factor of 1.39 RB/STB. Rock and reservoir fluid characteristics of this study are illustrated in Table 1.

Table 1: Rock and reservoir fluid characteristics.

Datum depth (ft.)	6100-6210	Total pore volume (MM Reservoir barrel)	21.373
Average reservoir pressure @ datum depth (psia)	3035	Reservoir temperature (°F)	210
Reservoir oil °API	35	Initial gas saturation (%) Two rock types	0
Initial oil saturation (%) (water wet rock)	0.85	Initial oil saturation (%) (oil wet rock)	0.807

MODEL DESCRIPTION

In this study, different injection scenarios were simulated through a commercial simulator, and a gridding network of reservoir was designed using geological data (Figure 1). In this network, the reservoir was divided longitudinally and latitudinally into 20 and 10 grid blocks. 5 grid blocks were defined for the reservoir in vertical direction (Table 2). Simplicity Block Center method was used to grade the reservoir. Geological indications and the information related to well drilling showed no fracture in the reservoir rock; therefore, single porosity model was used for the simulation of reservoir.

For better investigating the critical parameters affecting oil production, two rock types with different wettability conditions were chosen. The oil wet rock, which was from one of Iranian central oil fields, and water wet rock were chosen from one of Iranian southern fields. Reservoir rock has the same rock type in the model with rock compressibility of 3.4×10-7 (1/psi). The relative permeability of two types of rocks is shown in Figures 2 and 3. PVT data were prepared using the results of experiments on reservoir fluid. The reservoir fluid model was simulated by a commercial simulator PVTI © 2009 Schlumberger.

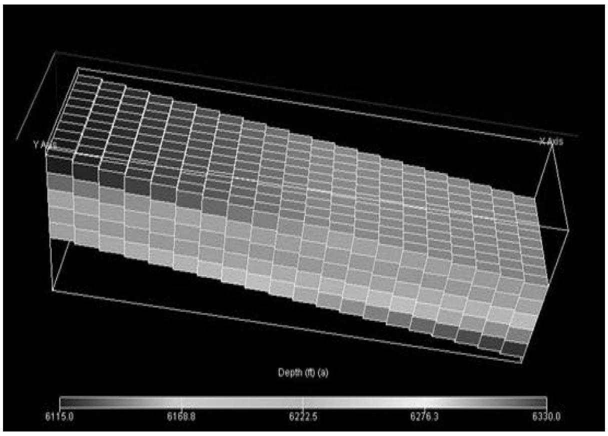

Figure 1: A three dimensional view of a synthetic model.

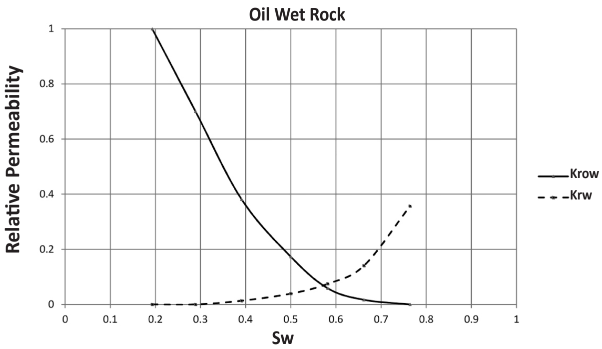

Figure 2: Relative permeability curves for oil wet rock (from one of Iranian central oil field).

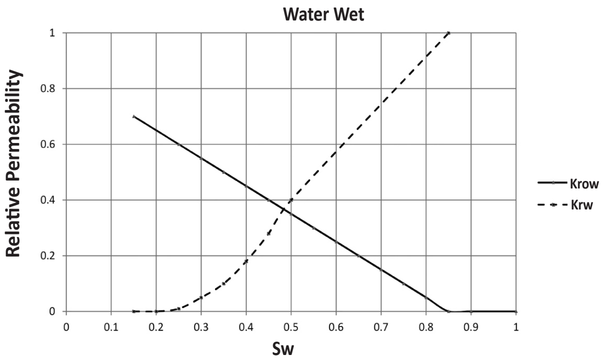

Figure 3: Relative permeability curves for water wet rock (from one of Iranian southern field).

Table 2: Model characteristics.

Type of porous medium	conventional	***x* grid block size (ft.)**	100
Number of cell in *x*-direction (Nx)	20	***y* grid block size (ft.)**	100
Number of cell in *y*-direction (Ny)	10	***z* grid block size (ft.)**	30
Number of cell in *z*-direction(Nz)	5	**Permeability in x, y, and z direction (m/day)**	80
Number of cell	1000	**Porosity(%)**	16

RESULTS AND DISCUSSIONS

Gas variation effect on oil recovery

In this case, water and gas were injected at a rate of 5000 STB/day and 3000 Mscf/day respectively. In WAG simulation, alternatively, the injected pressure is set at 3050 psia, which is equal to average reservoir pressure; the total amount of one pore volume was also injected. The results are listed in Table 4. Water wet rock has a higher incremental recovery compared to oil wet rock due to WAG injection process. In oil wet rocks, water cannot produce the oil which is wetted the walls of rock, but in water-wet rock, wetting phase is water, thereby pushing non-wetting oil through the production well so easier. Since the initial oil saturation for water-wet rock is different from oil-wet rock, for the correct comparison of the recovery for both rock types, the incremental recovery, which is equal to the difference between the recoveries due to WAG injection and the recovery obtained by natural depletion at the same time, was used.

Since minimum miscibility pressure (MMP) for carbon dioxide is less than other gases, so this gas can make miscibility at a low injected pressure, whereas other gas cannot do the same. Thus, by using this gas at a low injected pressure, high oil recovery can be obtained. In this part of study, first contact miscibility pressure (FCMP) and MMP for four different possible injecting gases were simulated by PVTI and ECLIPSE300 software (© 2009) Schlumberger respectively. It is well worth mentioning that for obtaining the more accurate MMP results, the dynamic slim tube simulator was chosen. In Table 3, the FCMP and MMP results for CO_2, solvent (40% C_2 and 60% C_1), N_2, and C_1 are presented.

Table 3: The amount of MMP and FCMP for different gases.

Component	CO_2	Solvent (40% C_2 and 60% C_1)	N_2	C_1
First Contact Miscibility Pressure (psia) Simulated by PVTI software	3400	3980	14600	6400
Minimum Miscibility Pressure (psia) Simulated by dynamic Slim tube	3000	3970	13200	5500

Table 4: Gas variation effect on oil recovery.

Component	CO_2	Solvent (40% C_2 and 60% C_1)	N_2	C_1
Incremental Recovery for Water Wet rock	37.45	37	33.07	22.1
Incremental Recovery for Oil Wet rock	29.53	26.40	22.91	16.94

Effect of Cycle Time of Injection

To investigate the effect of the injection period for each fluid (gas and water) on the efficiency of oil production, several cycle times were used. It was assumed that the cycle time for each injection fluid is the same. For example, if cycle time for water was one year, this value would be inserted into the software. The results of these simulations are shown in Figures 4 to 6. As the cycle time of injection increases, the recovery of producing oil increases (Figure 5). When gas is injected after water injection, water retains the easier flow of gas in the reservoir, so it makes higher sharing of gas in production. As the cycle time period increases, recovery rises, but increasing this parameter would cause the high production of water in production wells. When water reaches its breakthrough point, the effectiveness of water injection for gas phase will be reduced.

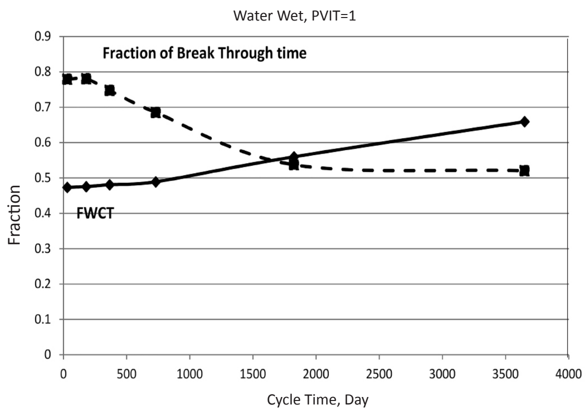

Figure 4: Fraction of break through time and FWCT (total field water cut) at different cycle times in water wet rock, total pore volume of injection (PVIT) =1; vertical axes is total field water cut (FWCT) based on the number of fractions, and it is dimensionless.

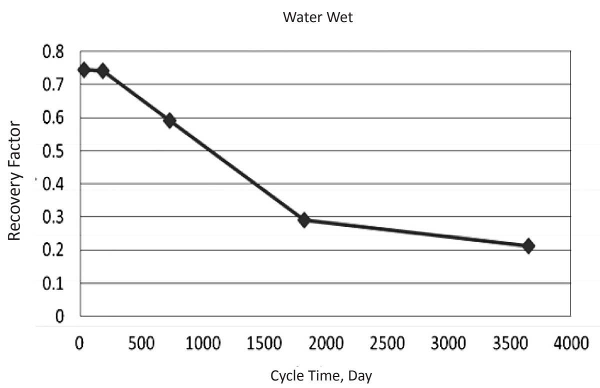

Figure 5: Recovery of oil production at different cycle times in water wet rock (PVIT=1).

Cycle time has an optimum value for each reservoir which must be obtained in order to minimize the amount of total field water cut (FWCT) and increase the breakthrough time for each injected phase. By increasing cycle time, one of the facilities (water or g=as) should be hung off, so it is unfavorable from economical points of view. To make breakthrough time dimensionless, each breakthrough time was divided by the total time of injection, which is a number between zero and one i.e.:

Fraction of breakthrough time = Breakthrough time / total time of injection (1)

To include economic dimension in the recovery for choosing the best cycle time, a new value was introduced as:

A= (B×C/D) (2)

where, *A* is a dimensionless value for the recovery of oil production (from economical view); *B* is the fraction of breakthrough time; *C* is recovery, and *D* is the dimensionless field water cut (FWCT).

By plotting *A* in terms of the logarithm of cycle time, the best cycle time could be determined, which is shown in Figure 6. When *A* value decreases, production is not economical. Since *A* has a constant value for a year cycle time, it must be concluded that the optimal value is one year cycle time.

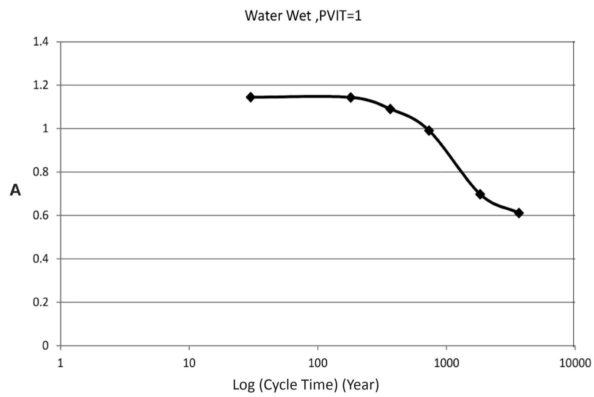

Figure 6: A value (recovery from economical view) at different cycle times in water-wet rock (PVIT=1).

Selecting the First Phase to Inject

Selecting the first phase to inject in the WAG injection process is one of key parameters which must be determined. Water and gas rates were selected 2000 STB/day and 1500 MSCF/day respectively. The total injected pore volume was 0.7 PV, and water-wet rock data were chosen as the input to the simulator. Injecting water phase as a first phase produces higher recovery value than the gas phase. At the beginning of injection, the reservoir oil saturation (also the permeability of oil phase) is high enough, and this value decreases over times of injection, so it is better to use a fluid (like water) which has higher mobility than gas and can produce more oil at the early times of injection. If gas phase was chosen as the first injected fluid, then the gas breakthroughs very soon and cannot produce oil like before the breakthrough time; thus, if water was injected after gas phase, the saturation and also permeability of oil phase would be decreased, and water could not produce high oil volume in comparison with the time when water was injected as the first fluid. In the case of injecting gas as the first fluid, if the cycle time of injection was increased, it would result in low oil production after early breakthrough times.

The results of these simulation scenarios are illustrated in Figures 7 and 8. Figure 7 shows the recovery comparison for several cycle times for the two conditions (W-G) and (G-W). (W-G) means injecting the water phase first, while (G-W) means injecting the gas phase first. Figure 8 shows the fraction of breakthrough time (FBT) of injection. As mentioned before, when water was first injected, FBT would be decreased, which means water very quickly reaches the producing well. When the gas was the first injected fluid, water FBT would then be increased. In this kind of injection, for the highest cycle time of injection, FWCT would be the minimum.

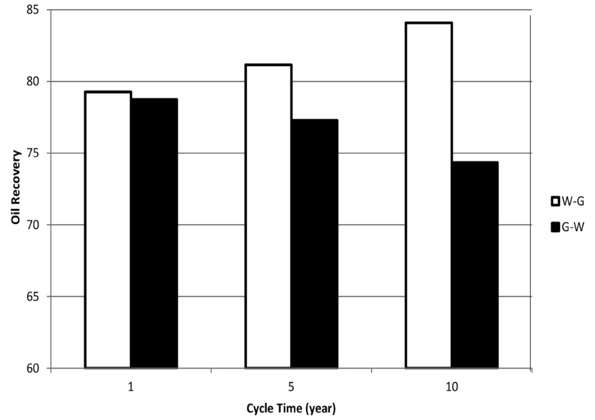

Figure 7: Recovery comparison for several cycle times for two conditions, namely W-G and G-W in water wet rock.

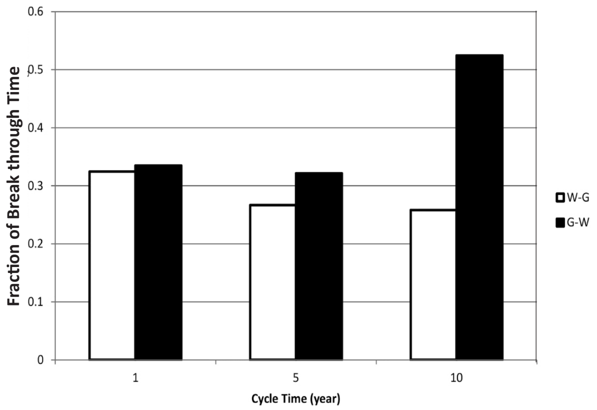

Figure 8: FBT comparison at several cycle times for two conditions, namely W-G and G-W in water wet rock.

Selecting the Best WAG Ratio

WAG ratio is defined as the total volume of water injection divided by the total volume of gas injection, i.e.:

$$WAG\,Ratio = \frac{Total\,Volume\,of\;\;Water\,injection}{Total\,Volume\,of\,Gas\,injection} \quad (3)$$

A new parameter was defined to better investigate the simulation scenarios. This parameter is TWAG ratio which is defined as the time of water injection in one cycle divided by the time of gas injection in one cycle, i.e.:

$$\text{TWAG ratio} = \frac{\text{Time of water injection in one cycle}}{\text{Time of gas injection in one cycle}} \quad (4)$$

Although by increasing WAG, ratio recovery increases, this is not the general rule, and, in addition to the WAG ratio, recovery depends on the water and gas rates. Two scenarios were defined, first water rate was considered constant, and to obtain the same amount of fluid injection at different TWAG ratios, the rate of gas injection was varied; in the second scenario, the gas rate was kept constant, and the water rate varied to have the same amount of fluid injection at several TWAG ratios. To investigate both total field water cut (FWCT) and breakthrough time, a dimensionless parameter was defined as:

$$FWCTT = \left[\frac{t_f}{t_o}(FWCT)\right] \quad (5)$$

where, t_f is equal to the total time of injection, and t_o is the time at which breakthrough is started. From the mathematical point of view, FWCTT is between zero and infinite. The brief review of the simulation process is presented below.

Constant Water Rate

In this part of the simulation, four water injection rates were selected: 7000 STB/day, 4000 STB/day, 3000 STB/day, and 1500 STB/day. At water injection rates, in order to inject one pore volume (1 PV) of the reservoir model, by choosing different TWAG ratios and using Equation 10, the appropriate gas injection rate could be chosen.

Total pore volume injected to the reservoir (PVIT) is equal to the sum of total water injected (PVIW) in the reservoir conditions plus the total gas injection in the reservoir (PVIG) conditions.

$$PVIT=PVIW+PVIG \quad (6)$$

$$PVIT= q_w \times t_w \times B_w + q_w \times t_w \times B_w \quad (7)$$

$$t_{total} = t_w + t_g \quad (8)$$

$$TWAG\,ratio = TWAG = \frac{t_w}{t_g} \quad (9)$$

$$q_g = \frac{PVIT(1+TWAG)}{t_{total}B_g} - q_w \frac{B_w}{B_g} TWAG \quad (10)$$

where, t_{total} is the total time of injection. When the water injection rate is constant, we perform simulation for a constant period of time in all the conditions. Hence, by knowing TWAG, gas rate can be obtained. When the water rate is low, gas must be injected at a high rate, and this could be uneconomical to prepare the facilities to inject gas at high rates. To involve the economic dimensions, a dimensionless parameter was introduced for WAG ratio as:

$$WAGG\,Ratio = WAG\,Ratio \times \frac{q_w}{q_g} \quad (11)$$

$$Economic\,desire \propto low\,gas\,rates \propto 1/q_g. \quad (12)$$

The results are shown in Figures 9 and 10. By increasing the WAG ratio at all water rates, the recovery would be increased. Also, at a constant WAGG ratio, by increasing the water rate the recovery and FWCTT increases are not desirable, and in order to maximize recovery and minimize FWCTT, the optimized WAGG ratio must be determined.

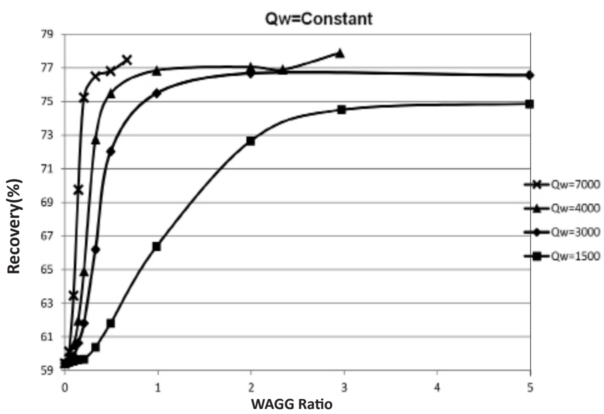

Figure 9: Recovery at different WAGG ratios; water rate is kept constant for each curve.

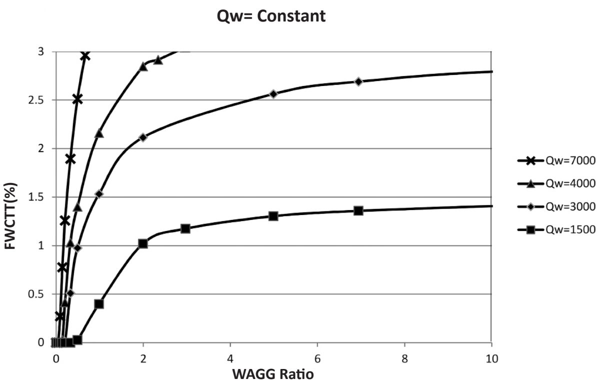

Figure 10: FWCTT at different WAGG ratios; water rate is kept constant for each curve.

Constant Gas Rate

For this type of simulation, the gas rates were remained constant. For having a constant volume of fluid injection, the water rates varied at different TWAG ratios. Two gas rates, namely 4000 MSCF/day and 1000 MSCF/day, were chosen for this purpose. The results of this simulation are shown in Figure 11. When gas was injected at a rate of 4000 MSCF/day, it resulted in a sharp increase in recovery from zero WAG ratios, and this reflects the water rate effect on production; after a quick increase in recovery, it reaches the optimized value and increasing WAG ratio after this stage does not affect the recovery; thus, it is very important to choose the optimized WAG ratio when gas rates remain constant. When the gas rate is 1000 MSCF/day for the same TWAG ratio of 4000 MSCF/day, a greater volume of water must be injected to have the same total volume of injection, and because of this, at low rates (like 1000 MSCF/day), recovery is higher in the range of low WAG ratios. However, by increasing the WAG ratio, it reaches the optimized value. FWCT for both gas rates has the same trend. Total pore volume injected to the reservoir is equal to the sum of total water injected in the reservoir conditions plus the total gas injected in the reservoir conditions, i.e:

$$PVIT=PVIW+PVIG \quad (13)$$

$$q_w = \frac{PVIT(1+TWAG)}{t_{total}B_w TWAG} - \frac{q_g B_g}{B_w(TWAG)} \quad (14)$$

where, B_g and B_w are gas and water formation volume factors respectively. When the gas injection rate is constant and the simulations are held for a constant period of time in all the conditions, water rate could be obtained by knowing TWAG and using Equation 14.

Selecting the Optimum Period and Time of Injection

In order to obtain the optimum time to inject after starting oil production and to select the best period of injection, three periods of 10 years, 20 years, and 40 years of injection were selected for a total of 40 years of production. For ten years of injection period, there were four possible statuses, namely an injection in the first decade, the second decade, the third decade, or the fourth decade of the production period. For a twenty-year injection period, there were two statuses of injections in the first half of the production or in the second period of the production time period. The best time to start injection is when the reservoir has not produced much oil and there is sufficient oil in the reservoir. This technique will be successful, if the saturation of oil is not reduced severely. This point is important to prevent the reservoir from reducing its productivity, and this is possible when the reservoir pressure and oil saturation does not reduce too much; in fact, when oil saturation and reservoir pressure reduces, the injection could not produce much oil from the reservoir, so for investigating the effect of these two parameters in oil recovery in different scenarios, a new value was introduced as defined by:

$$X=\Delta S_o \times P_{\text{start time of injection}} \quad (15)$$

$$X=(S_{wf} - S_{wi}) \times P_{\text{start time of injection}} \quad (16)$$

The results are depicted in Figures 11-13. It is important to note that when the productivity of oil reduces, the injection does not play an important role in production.

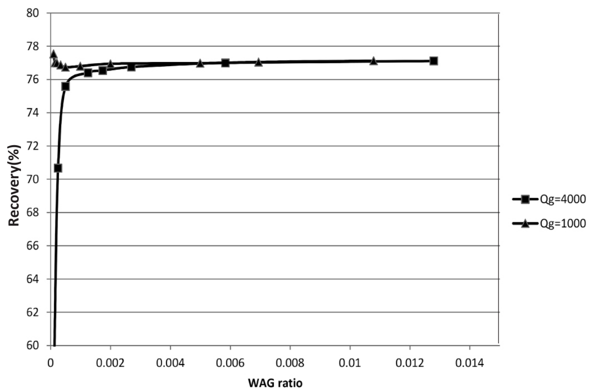

Figure 11: Recovery at different WAG ratios; gas rate is kept constant for each curve.

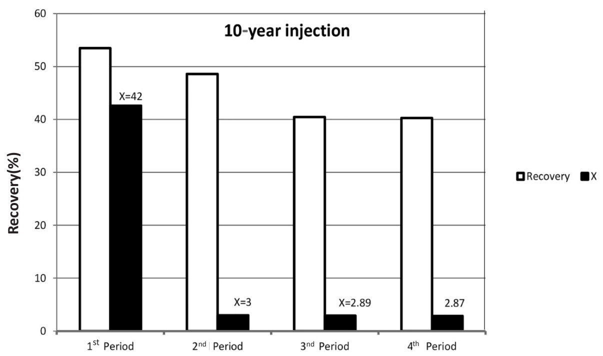

Figure 12: Recovery and X value for four possible statuses in a ten-year injection period.

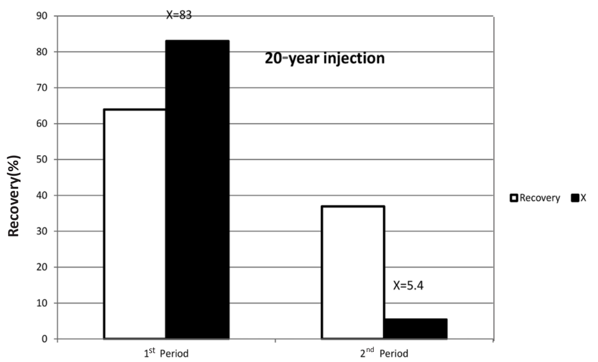

Figure 13: Recovery and X value for two possible statuses in a twenty-year injection period.

Figure 14 shows the amount of oil production based on injection time. For ten and twenty years of injections, the first injection modes were chosen; it is clear that increasing the time of injection does not mean higher oil production. For up to twenty years of injection, we could expect almost the same production, but when the injection process continues for forty years, recovery rate decreases, and, from an economical point of view, it is not an optimized period for the injection.

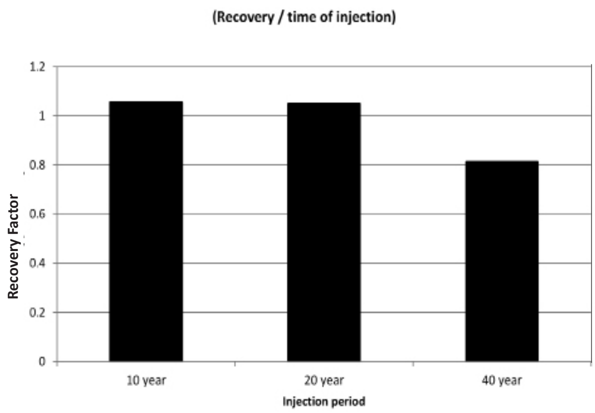

Figure 14: Recovery per time of injection for three different injection periods.

CONCLUSIONS

Based on the studies of different parameters affecting the WAG process, it is concluded that:

1- Carbone dioxide is miscible with oil at low pressures, so by using this gas in WAG injection process, the highest recovery will be achieved.

2- By increasing the cycle time of injection, recovery increases; however, increasing cycle time causes high water production, so the optimum value of cycle time must be found.

3- If water is first injected, recovery will be higher compared to when gas is first injected.

4- By increasing WAG ratio from zero, recovery increases dramatically; however, recovery increases very slowly by further increasing WAG ratio.

5- From an economical point of view, the optimum period of injection must be determined to have the maximum oil production at a minimum time of injection, and this depends on the reservoir pressure and oil saturation.

Abbreviation

API: American Petroleum Institute
EOR: Enhanced Oil Recovery
FCMP: First Contact Miscibility Pressure
FWCT: Total Field Water Cut
IOR: Improved Oil Recovery
K_{row}: Oil Relative permeability in presence of water
K_{rw}: Water Relative Permeability
MMP: Minimum Miscibility Pressure
Mscf: Thousand Standard Cubic feet
PVIG: Total gas injected
PVIT: Total Injected Pore Volume
PVIW: Total Water Injected
RB: Real Barrel
STB: Stock Tank Barrel
S_w: Water Saturation
WAG: Water Alternative Gas injection

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