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Managing Gas-Injection-Induced Excessive Water Production in Tight Oil Reservoirs by Optimizing Operational Constraints

Chi Zhang, Ye Tian, and Yu-Shu Wu, Colorado School of Mines

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Abstract

A CO_2 huff-n-puff pilot implemented in the Midland Basin demonstrated a significant oil rate improvement, but also witnessed an escalation in water-cut up to 0.3. A compositional model was established to consider the complex physics including cyclic stress changes, reopening of water-bearing layers, reopening of unpropped fractures and its resulting relative permeability shift. Our previously published work suggested that the reopening of unpropped fractures and its resulting relative permeability shift contributes most to the abnormal water cut surge after gas injection. In this study, we further proposed several operational constraints to manage such high water-cut occurrence after gas injection. The optimized simulation results suggested that around 1.5 times increase in recovery factor can be achieved after six CO_2 huff-n-puff cycles. Sensitivity analysis was subsequently conducted regarding parameters such as soaking time, injection time, and bottom-hole pressure. It was found that soaking time and bottom-hole pressure did not have much influence on cumulative oil production. Setting injection time as 150 days in each cycle can achieve the highest net present value. The primary objective of this study is aimed at optimizing techniques for conducting CO_2 huff and puff process to maximize oil production and minimize CO_2 emission.

Introduction

Horizontal well and multistage fracturing technologies have contributed to practical and economical shale oil production over the last decade. However, sharp decline production rate and low oil recovery still are challenging problems we need to solve. Gas injection turns out to be an efficient method to improve oil recovery from tight oil reservoirs. Mohammad et al. (2017) have investigated several designing parameters in cyclic CO_2 injection process to identify the effects of parameters on oil recovery, thus grasping the cyclic CO_2 injection behavior. They concluded injecting CO_2 too early or too late would adversely impact the injection efficiency and cut down the net present value. Longer injection time leads to higher oil recovery under a specific soaking time. Li and Sheng (2017) provided a basic understanding of key parameters which control cyclic CH_4 injection in shale rocks. It was found the incremental oil recovery from a single cycle decreased with the number in cycles increasing. For the soaking time, a shorter soaking time was able to

re-pressurize core more frequently to achieve higher oil recovery provided that in a fixed operation period. Within a single cycle, they concluded a longer soaking time was needed for a larger core to maximize oil recovery compared with a smaller core. Gamadi et al. (2014) evaluated the potential of CO_2 huff and puff according to many operating parameters in their lab-scale model. Their laboratory results suggested that injection pressure depends on shut-in time, while injecting CO_2 at a pressure higher than MMP makes no difference on ultimate recovery factor. In addition, short shut-in periods outperformed using long shut-in period with fewer cycles in terms of oil recovery factor. Yu et al. (2016) discussed the roles of soaking time in shale core plugs during huff-n-puff process. The experimental results showed that recovery factor increases with soaking time within limits and a longer time makes no benefit on recovery factory. The soaking times in their lab-scale model varied from 0.25 hours to 48 hours. The general trend was some earlier cycles yield more oil than the rest cycles and an optimal soaking period existed, which was not only beneficial to improve oil recovery, but also shortened the operation time and reduced costs. Wang et al. (2013) conducted cyclic CO_2 injection in a 973 mm-long composite core. Operational parameters, such as injection pressure, slug size and CO_2 injection rate, have been analyzed. Their experimental results showed that the response of CO_2 injection heavily declines in the subsequent cycles in comparison with previous cycles. A longer soaking time has a larger impact in the third cycle than the first two cycles. Jeong and Lee (2015) performed a pilot scale simulation to maximize the oil recovery. It suggested oil recovery of the optimized case has increased by 9.8% and 12% compared with stimulated case without optimization and primary production, respectively. Yu et al. (2014) conducted a series of sensitivity studies in a numerical model for Bakken Formation and identified that CO_2 injection rate was the most critical parameter in huff-n-puff process, CO_2 injection time and number of cycles followed by it.

Model build up

A compositional model was established to consider the complex physics including cyclic stress changes, reopening of water-bearing layers, reopening of unpropped fractures and its resulting relative permeability shift. The set-up of the model was discussed in detail in our previous work (Zhang et al., 2019).

Results and discussions

Sensitivity analysis was primarily used to identify the simulation results under variation of different reservoir parameters thus guiding practical production. Generally, operating conditions in sensitivity analysis include parameters, such as injection rate, injection temperature, injection time, soaking time and production time. In this study, soaking time, injection time, and bottom hole pressure will be investigated concretely. The case that already matched field observation (Zhang et al, 2019) was utilized as the base case for sensitivity analysis here, and we attempt to adjust the period of injection and soaking phases to identify whether the economic benefits will be improved. The base case started with CO_2 injection on October 1st, 2021 for 50 days, then shut in the well for 10 days during soaking period and reopened the well to production for 300 days. Injection rate was set as 60,000 ft^3/day and bottom-hole pressure of producer was maintained at 1,200 psi. Six cycles were conducted to predict the cumulative oil and water production.

Effect of soaking time

First, we investigated the effect of soaking time on cumulative oil production. The cumulative oil production histories at different soaking times (soaking 1D, 5D, 10D, 50D and 100D) for six cycles were shown in Figure 1. The cumulative oil production of those five cases were summarized in Table 1. There was a general trend that late cycles yielded more oil than the earlier cycles among five cases. Cumulative oil production ranges from about 3,428 to 3,462 bbl, and a longer soaking time did achieve a slightly higher cumulative oil production. However, the small increase might not make up for the operating costs. Therefore, a shorter soaking time is suggested to the development plan of this reservoir so as to shorten the development time.

Also, it was probably because of the instantaneous equilibrium within the CMG-GEM simulator, the soaking time thus does not make any major difference on enhancing cumulative oil production.

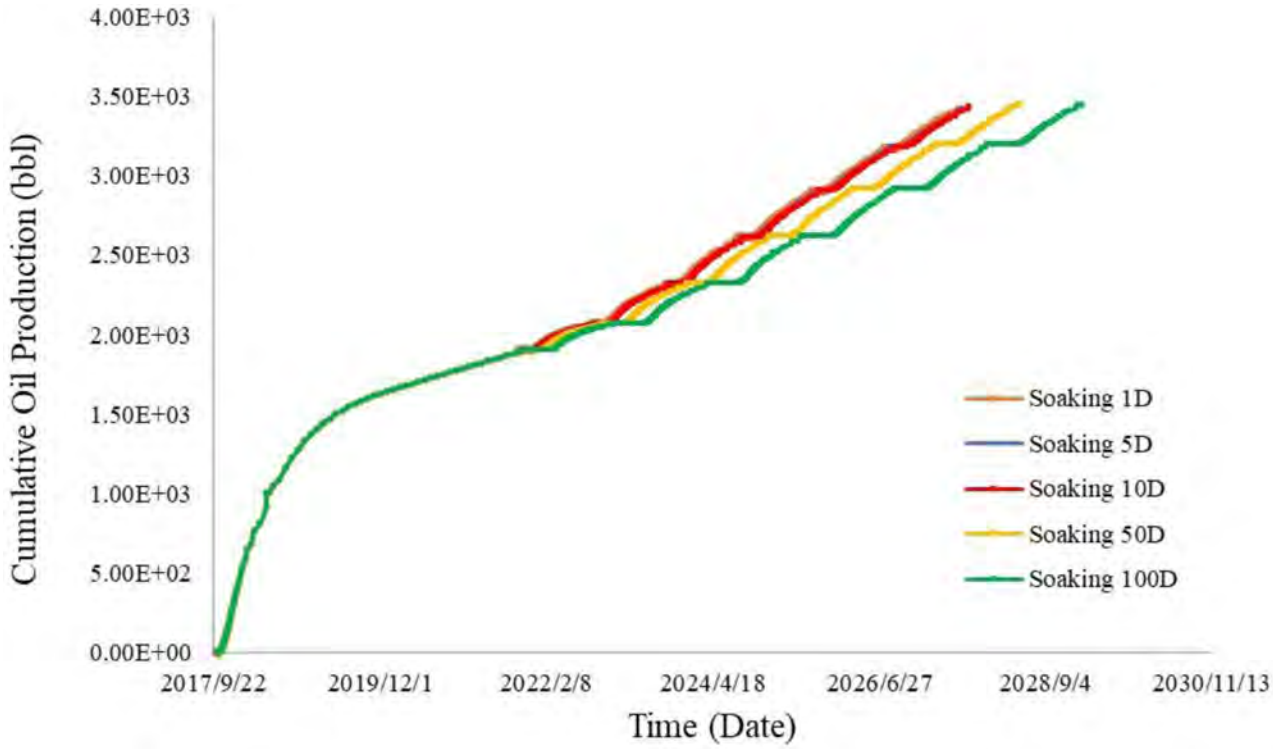

Figure 1—Cumulative Oil Production at different soaking times.

Table 1—Cumulative Oil Production at different soaking times

Soaking Time in Each Cycle	Injection Starts Date	End Date After Six Cycles	Cumulative Oil Production (bbl)
1	2021-10-01	2027-07-08	3428.64
5	2021-10-01	2027-08-01	3436.22
10	2021-10-01	2027-08-31	3443.95
50	2021-10-01	2028-04-27	3458.19
100	2021-10-01	2029-02-21	3462.41

To further analyze the change during the soaking period, the matrix pressure variations and fracture gas saturation variations in one cycle of huff-n-puff process (before CO_2 injection, soaking 11D, 42D, 73D and 100D) were examined (Figure 2 to Figure 6). We chose first I plane and J, K 2D view of matrix pressure as the representative to identify the variation. The 15th plane and I, K 2D view was chosen to study the gas saturation in fracture system (Figure 7 to Figure 11). The reason why we chose the 15th plane was because the well was located in this plane. Thus, apprent vaiations may appear and were better to identify. It was observed that the matrix pressure gently decreased with the increase of soaking time and became stable after soaking 42 days. Also, gas saturation in fracture nearly had no decrease after soaking 42 days, which means that the gas have diffused the whole reservoir in a short time and longer soaking time turned out to be meaningless.

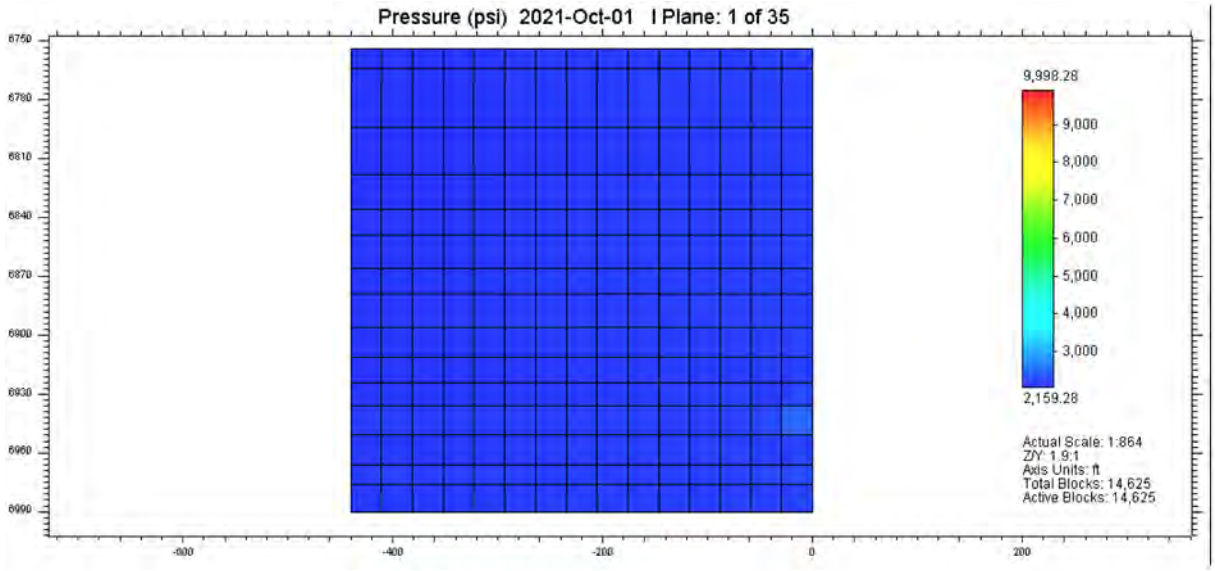

Figure 2—Matrix pressure before CO_2 injection.

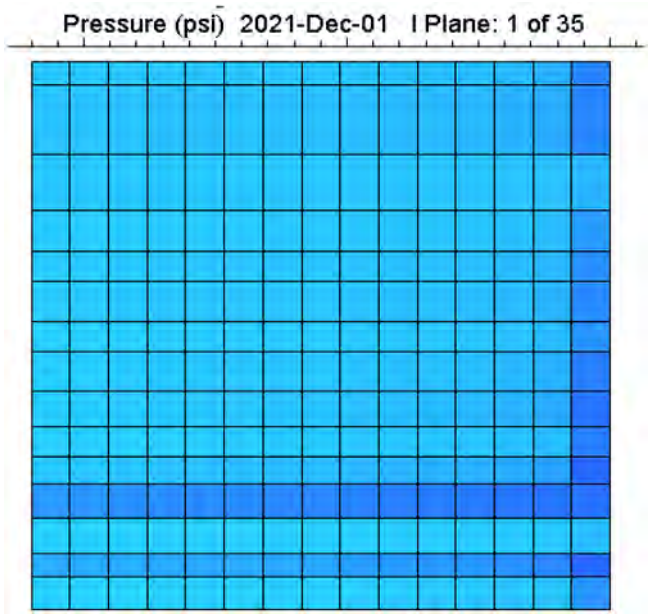

Figure 3—Matrix pressure at soaking 11D.

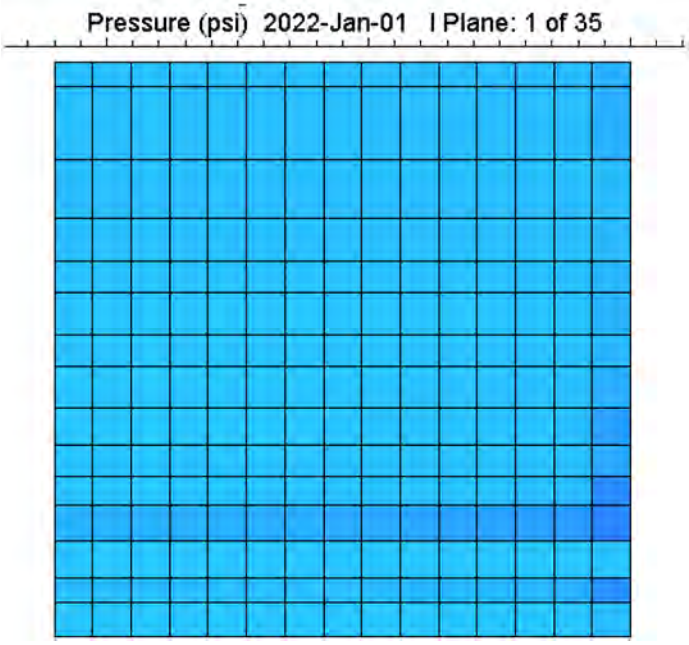

Figure 4—Matrix pressure at soaking 42D.

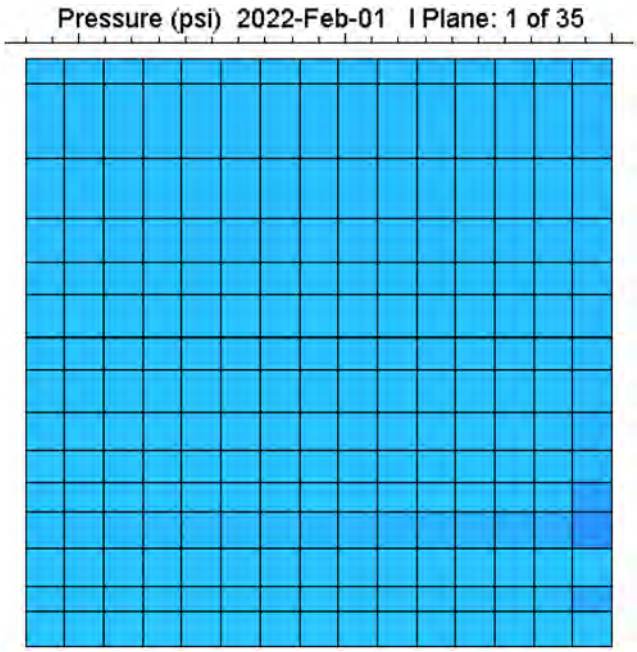

Figure 5—Matrix pressure at soaking 73D.

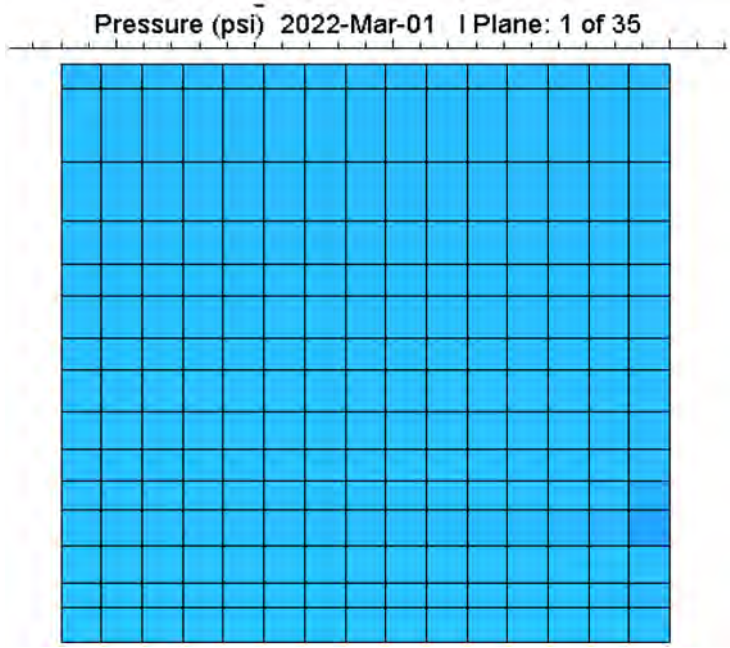

Figure 6—Matrix pressure at soaking 100D.

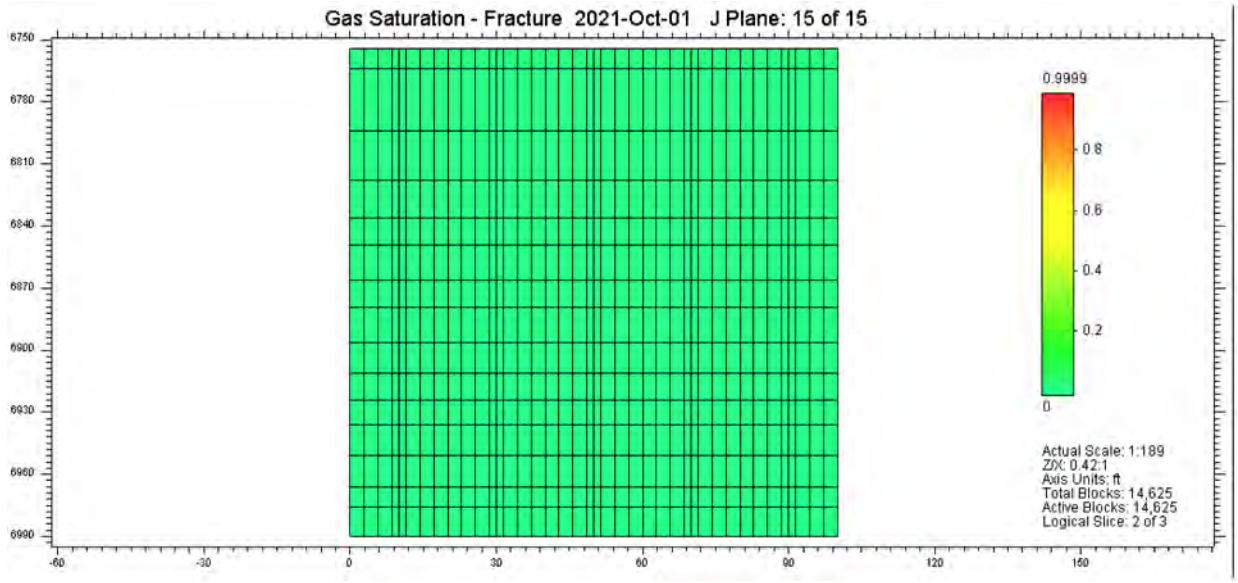

Figure 7—Gas saturation in fracture system before CO_2 injection.

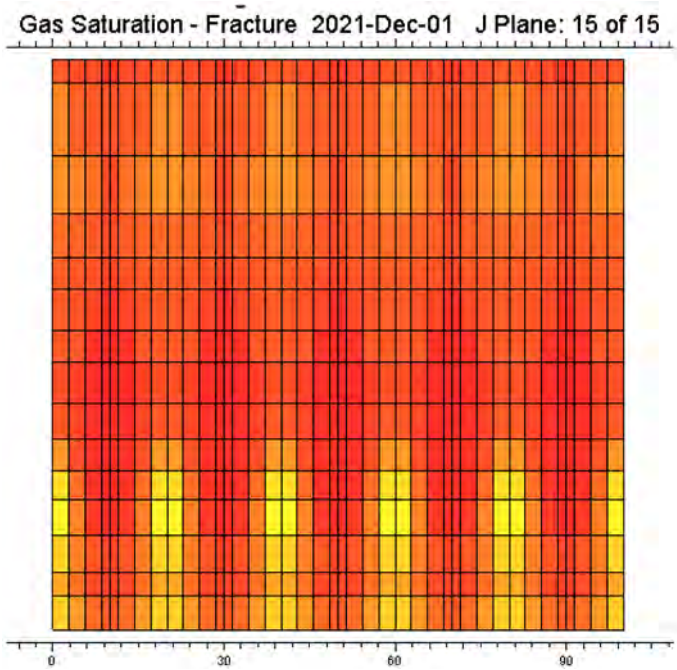

Figure 8—Gas saturation in fracture at soaking 11D.

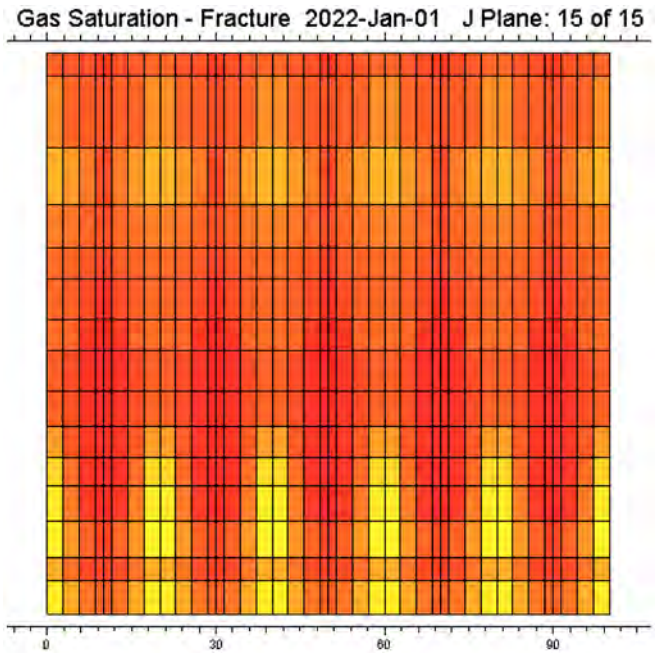

Figure 9—Gas saturation in fracture at soaking 42D.

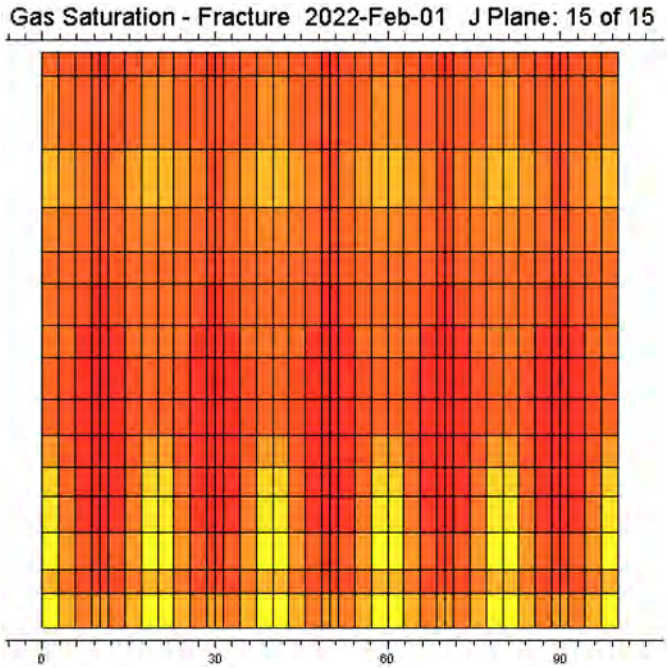

Figure 10—Gas saturation in fracture at soaking 73D.

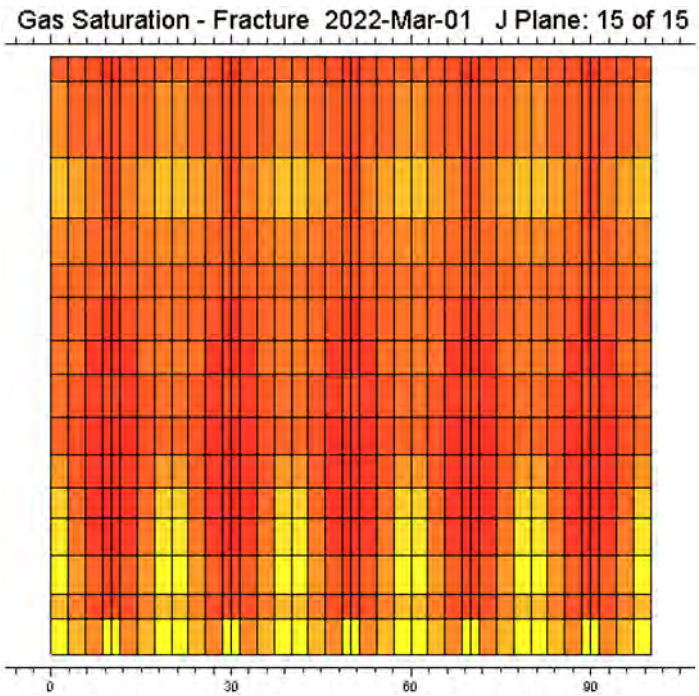

Figure 11—Gas saturation in fracture at soaking 100D.

Effect of bottom-hole pressure

Bottom-hole pressure was recognized as the most crucial operating parameter in oil industry. Four cases were run under conditions that bottom-hole pressure (BHP) of the producer maintained at 800 psi, 1,000 psi, 1,200 psi, and 1,500 psi. The case that well produced at a constant BHP 1,200 psi was used as the base case. Profiles of bottom-hole pressure of producer were shown in Figure 12. It was found that the well bottom hole pressures were strictly followed the BHP constrains. Table 2 gives the detailed results of cumulative oil production after conducting six huff-n-puff cycles. From the table, even cumulative oil production did increase as the BHP decreased, the increased amount was insignificant. Figure 13 exhibits that the water-

cuts behave in the same trend at four different bottom-hole pressure. Thus, well produced at condition BHP 1,500 psi is suggested. In addition, we concluded BHP is not a crucial factor, and tight control over BHP may not yield benefits both in rising oil production and reducing water production.

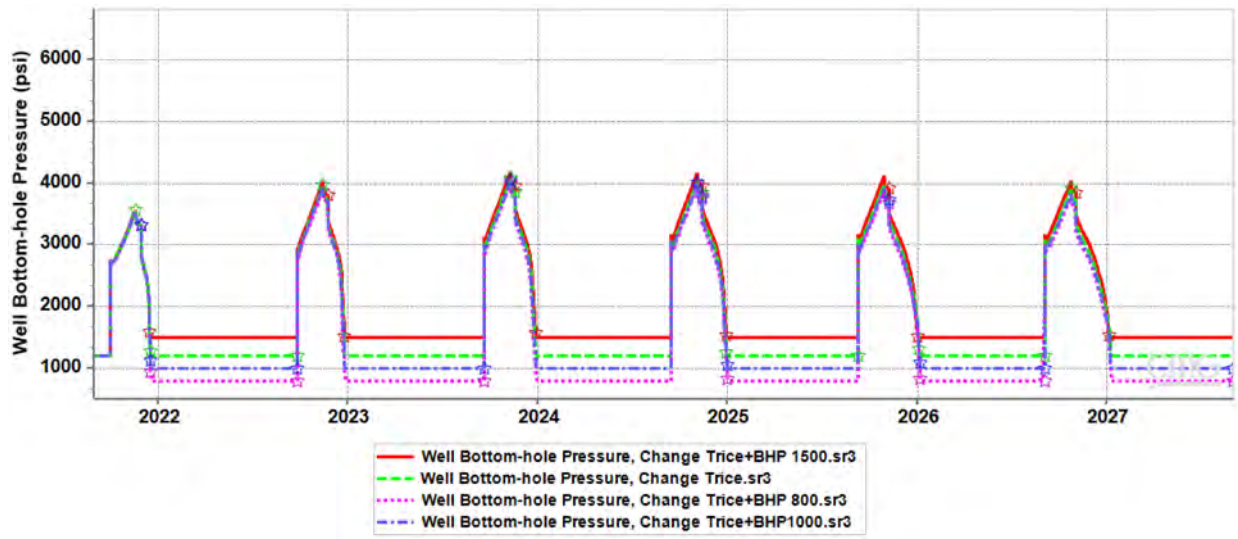

Figure 12—Profiles of well bottom-hole pressure of producer.

Figure 13—Profiles of water cut at different bottom-hole pressure.

Table 2—Cumulative Oil Production under different BHP

Well Bottom-hole Pressure (psi)	Cumulative Oil Production (bbl)
1500	3395.76
1200	3440.50
1000	3442.64
800	3481.33

Effect of injection time and economic analysis

In this section, effect of injection time (30 days, 50 days, 100 days, 150 days, and 200 days) on production in each cycle was investigated and an economic analysis was conducted. Figure 14 to Figure 17 illustrate

profiles of oil rate at five different injection times, respectively. The highest oil rate reached to 5.3 bbl/d, which occurred at the case injecting 200 days. The lowest oil rate was around 0.5 bbl/d when injecting 30 days. Figure 18 gives the cumulative oil production at different injection times. The maximum cumulative oil production was 5,649.1 bbl, which was achieved at condition injecting 150 days. The minimum cumulative oil production was 2,845.3 bbl when injecting 30 days.

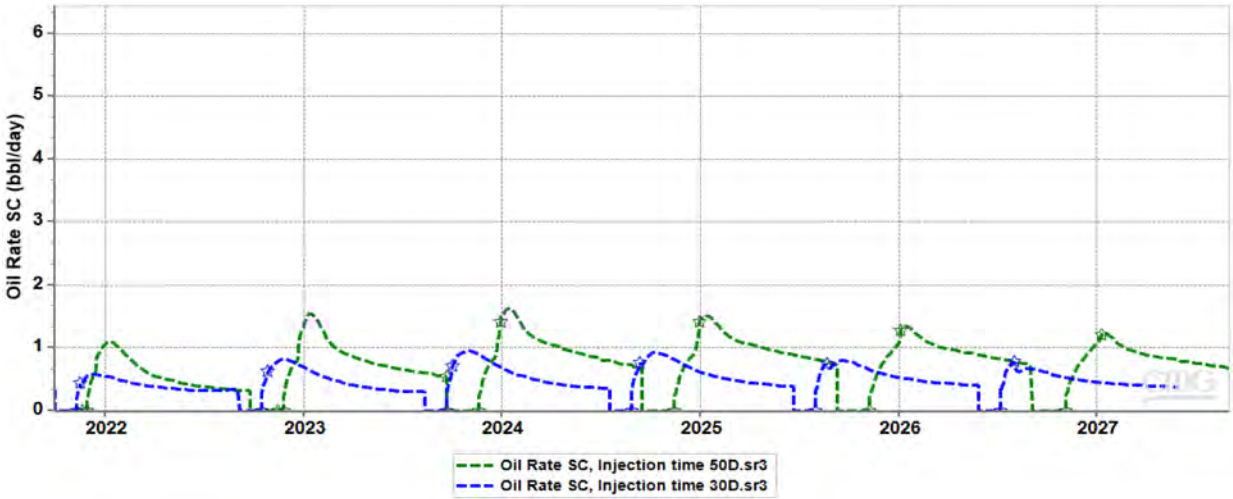

Figure 14—Oil rate when injecting 50 days and 30 days.

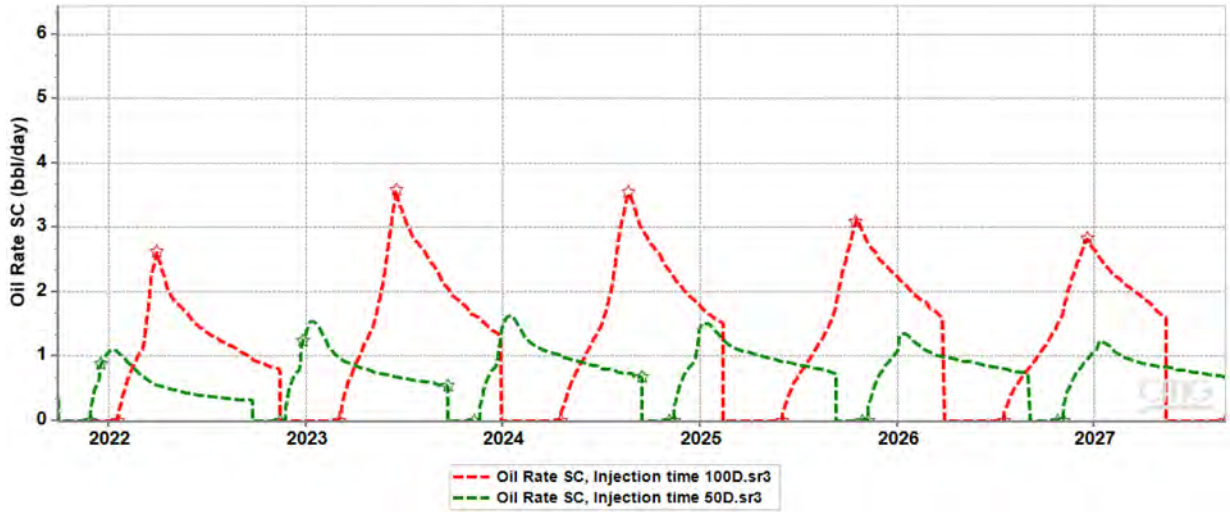

Figure 15—Oil rate when injecting 50 days and 100 days.

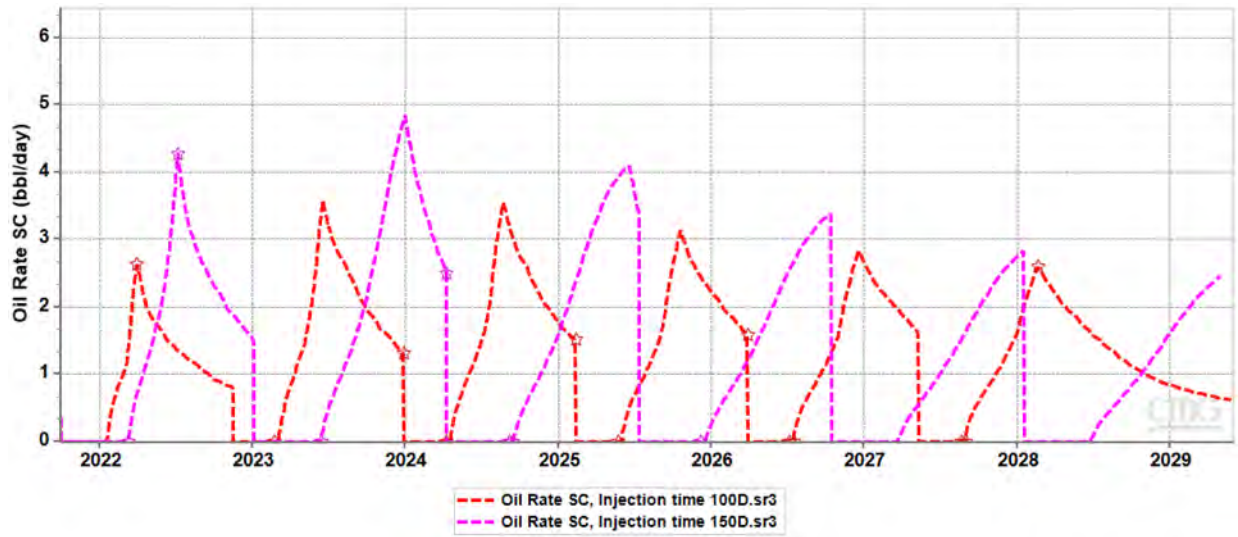

Figure 16—Oil rate when injecting 150 days and 100 day.

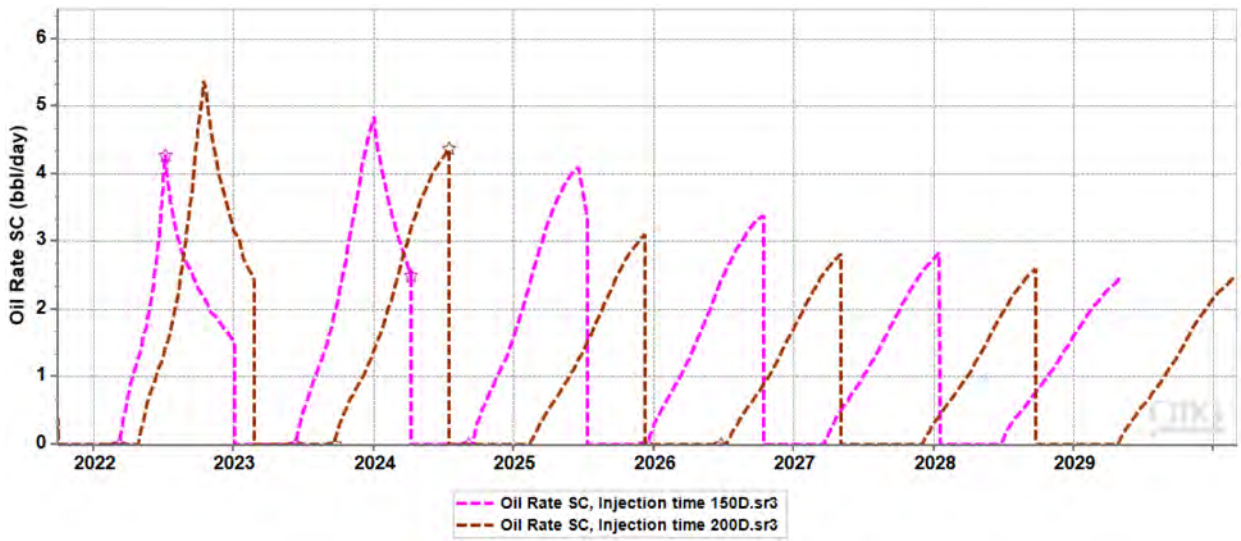

Figure 17—Oil rate when injecting 150 days and 200 days.

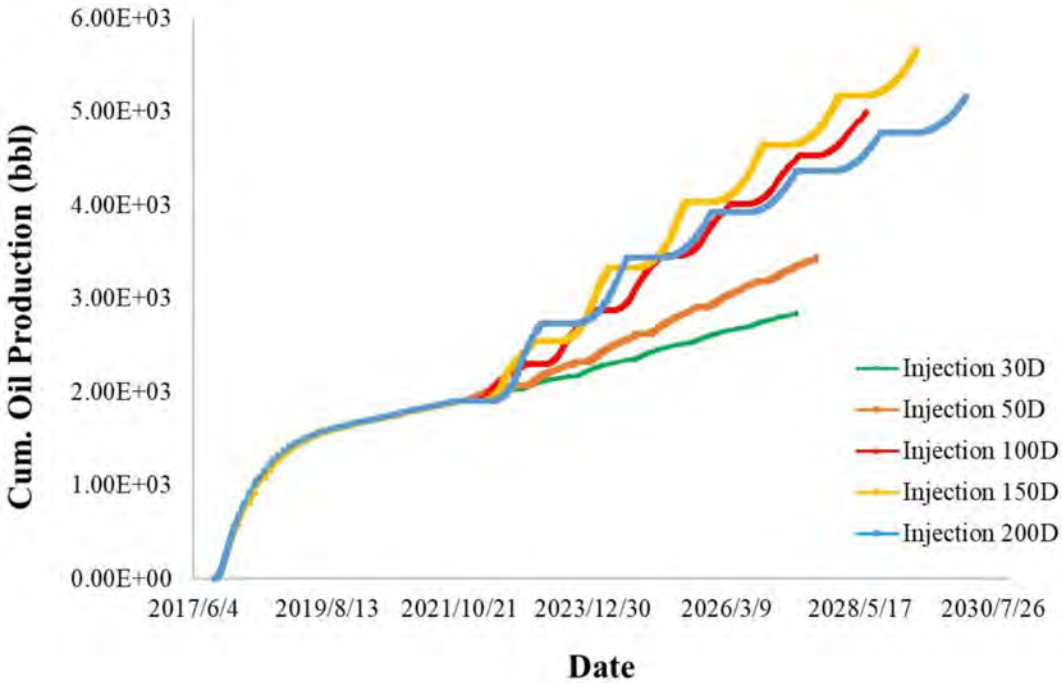

Figure 18—Cumulative oil production at different injection time.

It was observed the cumulative oil production of injecting 150 days was larger than the case of injecting 200 days. Figure 17 suggests oil rate of the first cycle when injecting 200 days is larger than injecting 150 days while next five cycles becomes smaller than it. Then, we found more CO_2 was produced from producer when injecting 200 days from Table 3. Therefore, we concluded that larger amount CO_2 injection has displaced oil into far places in reservoirs and away from wellbore, thus less oil production was achieved when injecting 200 days.

Table 3—Components produced in oil and gas phases between injecting 150 and 200 days

	150 Days			200 Days		
	Produced in Oil (moles)	Produced in Gas (moles)	Total (moles)	Produced in Oil (moles)	Produced in Gas (moles)	Total (moles)
CO_2	4.12E+04	2.57E+07	2.57E+07	3.74E+04	2.72E+07	2.72E+07
CH_4	2.86E+03	3.54E+06	3.54E+06	2.75E+03	3.33E+06	3.33E+06
N_2-C_2	1.64E+04	9.62E+05	9.78E+05	1.57E+04	9.06E+05	9.22E+05
C_3	9.42E+04	7.12E+05	8.06E+05	8.91E+04	6.71E+05	7.60E+05
C_{4-6}	6.28E+05	5.52E+05	1.18E+06	5.81E+05	5.31E+05	1.11E+06
C_{7-15}	2.39E+06	2.03E+04	2.41E+06	2.26E+06	2.15E+04	2.28E+06
C_{16-24}	5.95E+05	5.67E-02	5.95E+05	5.62E+05	6.14E-02	5.62E+05
C_{25+}	4.98E+05	4.63E-08	4.98E+05	4.70E+05	4.97E-08	4.70E+05

Figure 19 to Figure 22 show the profiles of water-cut when injecting different days. All cases showed that water-cut decreased with the number of cycles increasing except the case injecting 30 days. Generally, average water-cut decreased as injection time increasing. However, the case injecting 150 days owned a lowest average water-cut compared with the other four cases. Its water-cut was around 0.6 in the first cycle and stabilized at 0.5 in the following cycles.

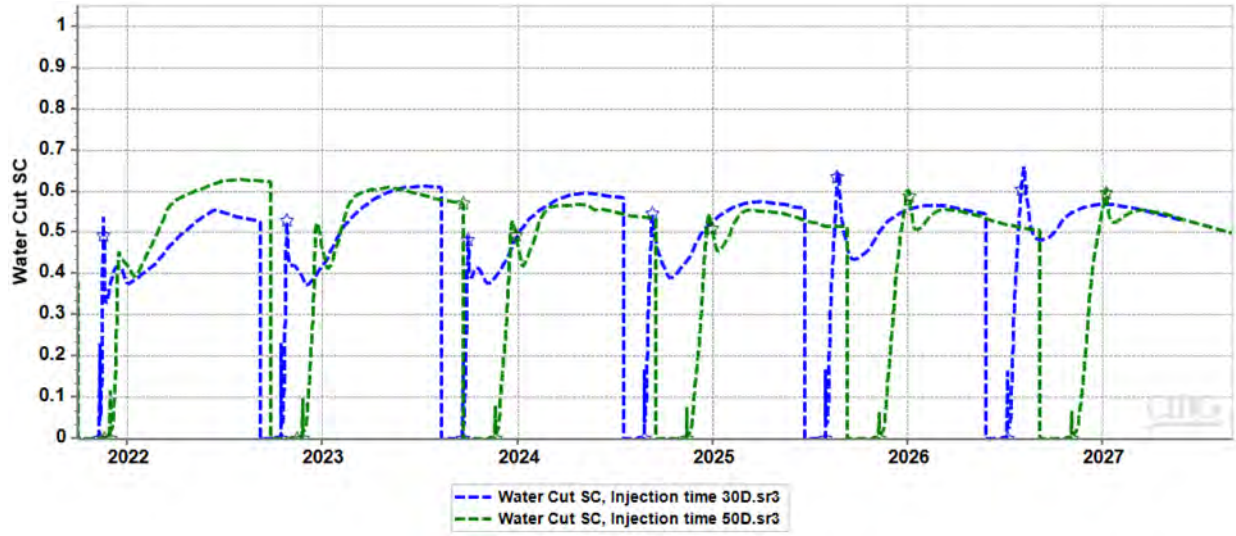

Figure 19—Water-cut when injecting 50 days and 30 days.

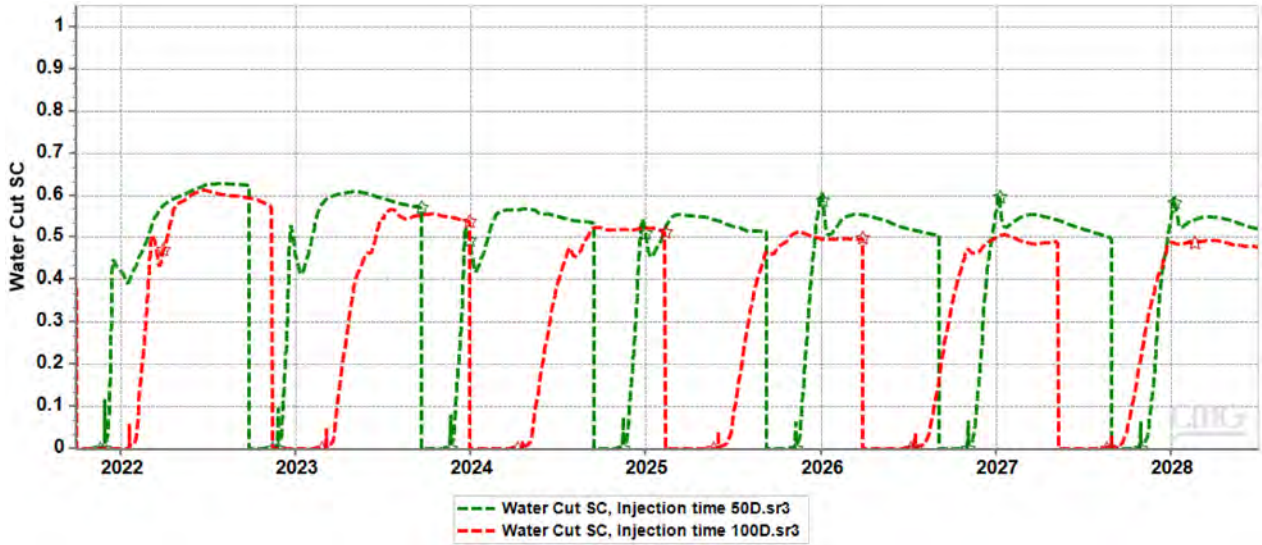

Figure 20—Water-cut when injecting 50 days and 100 days.

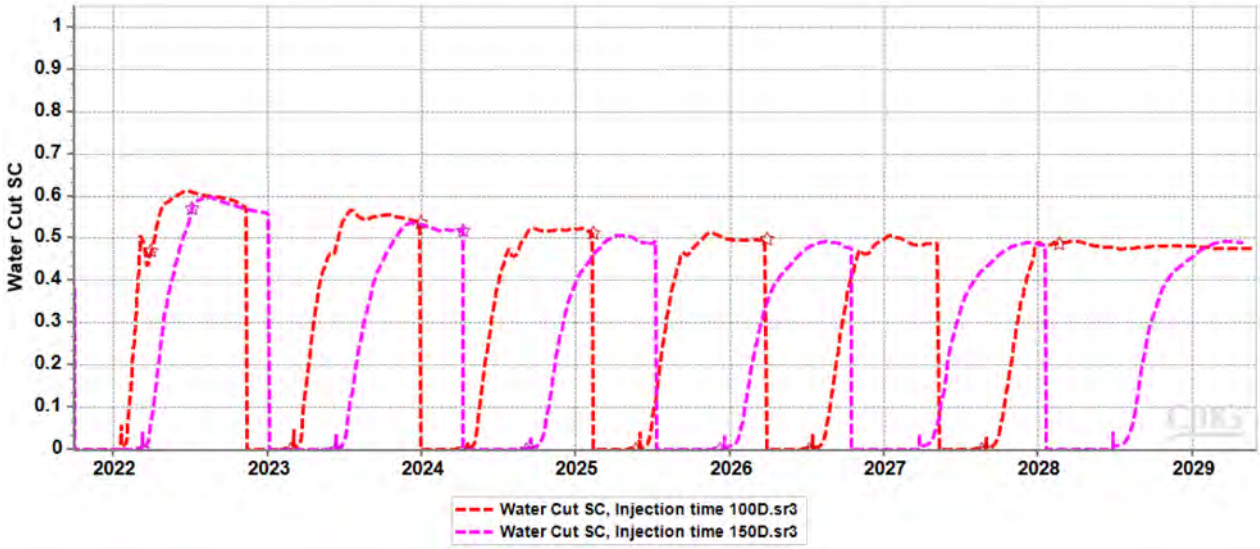

Figure 21—Water-cut when injecting 150 days and 100 days.

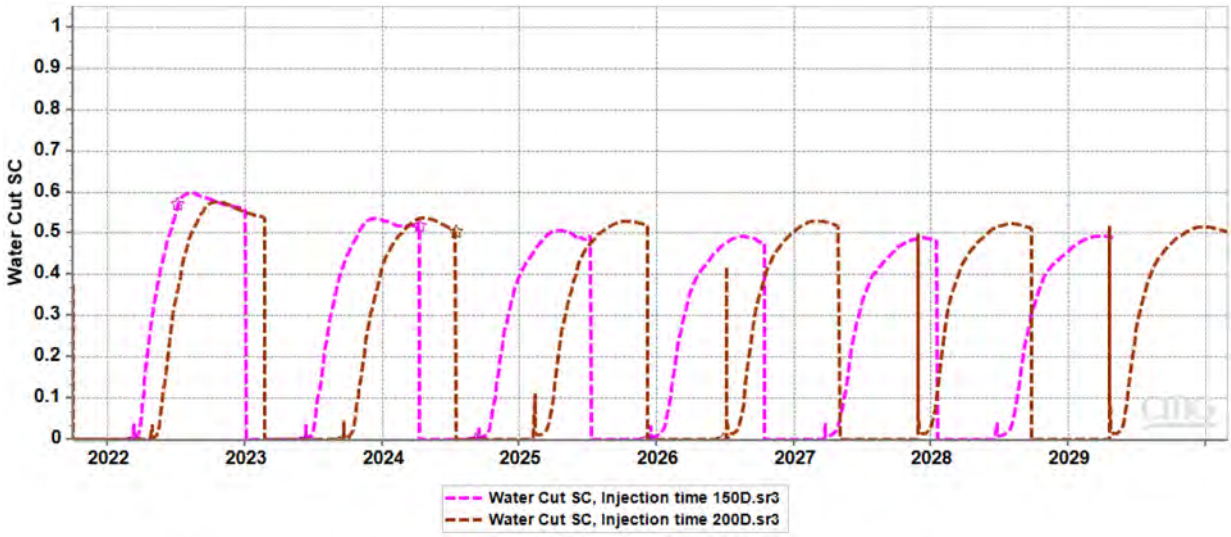

Figure 22—Water-cut when injecting 150 days and 200 days.

In this sensitivity analysis, we found that soaking time and bottom-hole pressure did not have much influence on cumulative oil production. However, injection time did exert a significant effect on it. It needs to mention that injection time may not be conducted in such a long time in real field operation. For the case of injecting 200 days, the bottom hole pressure of injector already exceeded 10,000 psi and reaches breakdown pressure, while we only investigate the sensitivity of injection time in theory.

To compare the profits of different schemes, Net present value (NPV) is taken as our objective function in economic analysis. NPV is the difference between the present value of cash inflows and cash outflows during a period of time. Oil production is the source of income and gas injection costs. We set monthly discount rate at i=0.008, CO_2 price at \$1.5/Mcf and oil price at \$70/bbl. The purchase of CO_2 usually accounts for the largest project cost. The value of CO_2 behaves as a commodity and its price was determined by pressure, pipeline quality, and accessibility (National Energy Technology Laboratory, 2010). The oil company has its own pipeline in our case thus the CO_2 is cheaper than common market price. The NPV evaluation is performed for six cycles among five cases, and 2021 Oct 1st was set as the start of prediction.

$$NPV = \sum_{k=0}^{t} \frac{(NCF)_k}{(1+i)^k}$$

where

k= month

t= project life

$(NCF)_k$= net cash flow for period k

i= discount rate (fraction)

According to Figure 23, NPV was largely improved when the injection time increased. We found that injecting 150 days is the optimal scheme among all cases. Thus, NPV can be further improved with the injection time increasing. However, when the injection time was set as 200 days, NPV decreased with the increase of injection time in comparison with injecting 150 days. It was because the benefit of increment oil production cannot make up for the costs due to gas injection in a certain degree. Compared with base case (injecting 50 days), the optimal simulation case has a longer cycle period and NPV will reach to $125,825 on April 22nd, 2029. It did produce more oil, while more gas was injected into the well.

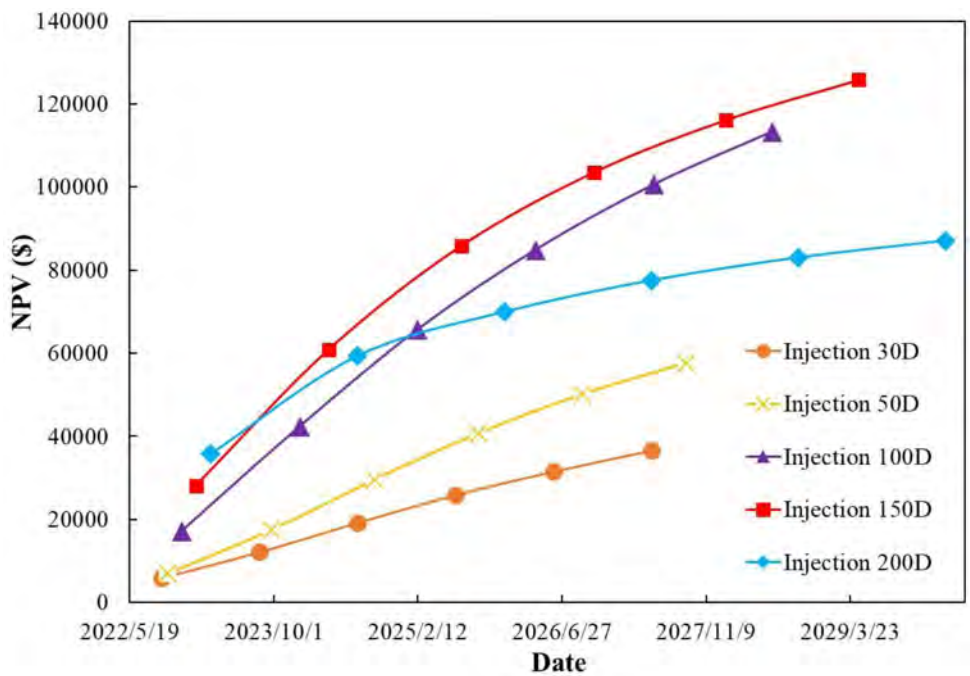

Figure 23—Net present value variations under different injection times.

Conclusion

Following conclusions may be drawn based on the above study and analysis.

1. The optimized simulation results suggested that around 1.5 times increase in recovery factor can be achieved after six cycles compared with primary depletion.
2. Bottom hole pressure (BHP) is not a crucial factor, and tight control over BHP may not yield benefits both in rising oil production and reducing water production.
3. Sensitivity analysis was conducted regarding parameters, such as soaking time, injection time, and bottom-hole pressure. Soaking time and bottom-hole pressure have minor influence on cumulative oil production. However, injection time did have a significant effect on cumulative oil production as well as water cut. Setting injection time as 150 days in each cycle can achieve the highest net present value.

Acknowledgements

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