Enhanced Gas Recovery with Carbon Dioxide Sequestration in a Water-drive Gas Condensate Reservoir: a Case Study in a Real Gas Field

Hossein Zangeneh[1]* and Mohammad Amin Safarzadeh[2]

[1] Ahwaz Research Center, Research Institute of Petroleum Industry (RIPI), Ahvaz, Iran
[2] Tehran Energy Consultants Company (TEC), Tehran, Iran

ABSTRACT

Gas reservoirs usually have high recovery due to high mobility and low residual gas saturation, although some of them producing under water-drive mechanism have low recovery efficiency. Encroachment of water into these reservoirs traps considerable amount of gas and increases the maximum residual gas saturation, which results in the reduction of gas and condensate production. Generally, the recoveries of water-drive gas reservoirs vary between 35-75%, whereas depletion-drive reservoirs exhibit recoveries near 85%. In this work, a method was proposed for reducing water encroachment, sweeping reservoir gas content effectively, and enhancing the hydrocarbon recovery consequently. To this end, a condensate gas reservoir model, located in the south of Iran, was chosen to study the process. The injection was performed above the bottom-up aquifer from two horizontal wells, and the base gas was produced by four vertical wells. Three cases of inactive aquifer (Case I), active aquifer (Case II), and active aquifer with CO_2 injection (Case III) were studied subsequently. The proposed gas-gas displacement method increases the recovery of reservoir especially the recovery of heavier components composing the main part of the condensate. Moreover, the injection of a huge volume of CO_2 without significant CO_2 production can be interesting from an environmental point of view and can be considered as a CO_2 sequestration process.

Keywords: Water-drive, Gas Condensate Reservoir, Carbon Dioxide, Enhanced Gas Recovery, Sequestration

INTRODUCTION

The recovery efficiency of gas reservoirs which are not in association with aquifers (depleting gas reservoirs) are usually as high as 70–85% of the original gas in-place (OGIP), without considerable water production [1-2]. However, recoveries of water-drive gas reservoirs range between 35-75% due to both relatively low sweep efficiency and the entrapped gas in the water-invaded zone [2-3]. Initially, physical properties such as the residual gas saturation (S_{gr}) behind the water front govern ultimate recovery of these reservoirs [4]. By increasing production and pressure drop, water moves to pores and throats filled with gas, and the water displaces the gas incompletely. Capillary pressure and relative permeability effects halt the flow of gas. Thus, water just passes through the rock volume [5]. Some methods have been proposed and used for increasing the recovery of water-drive gas reservoirs, i.e. blow-down technique (producing gas at a high rate to exceed the rate of water invasion into

***Corresponding author**
Hossein Zangeneh
Email: zangeneh@ripi.ir
Tel: +98 61 3444 2909
Fax: +98 61 3443 3436

Article history
Received: September 23, 2015
Received in revised form: April 01, 2016
Accepted: May 25, 2016
Available online: Jun 20, 2017

the gas zone) and up-dip production (producing water from down-dip and gas from up-dip) [6-7]. Also, the problem of high water-cut of these reservoirs are solved by reperforating the production wells in an uninvaded zone. However, these methods have some disadvantages like water conning and sand production for blow-down method and high operational cost of up-dip technique [6]. In many cases, the reperforating causes high cost of workover. Moreover, this solution does not prevent the gas entrapment in the water-invaded zone. Matthews et al. reported that the rapid de-pressurization of gas condensate reservoirs can re-mobilize up to 10% of the original gas in place (OGIP) entrapped due to water influx [8].

The last descriptions of water-drive reservoirs demonstrate the low recovery and necessity of employing enhanced gas recovery methods in these reservoirs. One of the effective methods proposed to enhance the ultimate recovery of these reservoirs is gas-gas displacement method. Enhancing gas recovery by gas-gas displacement can be achieved economically in several situations. For mature volumetric gas reservoirs suffering from low productivity due to low reservoir pressure, the injection of waste gas increases the ultimate gas recovery by maintaining gas production rates and preventing premature well abandonment. For water-driven gas reservoirs, pressure maintenance by gas injection will serve to retard the influx of aquifer and to partially mitigate water coning caused by excessive pressure drawdown [9]. The crucial aspect of designing the gas-gas displacement technique is selecting a proper displacing gas for EGR process. Carbon dioxide is an appropriate candidate for injection into the gas reservoirs. CO_2 is denser than natural gas (2 to 6 times depending on reservoir conditions) and segregates in the production zone by the gravity. It has lower mobility than natural gas due to its higher viscosity, which creates a high displacing efficiency in EGR process [10]. The other reason for choosing CO_2 for EGR process is sequestering this gas in a geological structure. Gas reservoirs are appropriate candidate for CO_2 storage due to high capacity and integrity. Therefore, the process of carbon dioxide injection can be employed as a multi-objective solution.

The data collection of various types shows that global surface temperature have increased by 0.7 Kelvin since the 19th centuries, which is the result of an increase in greenhouse gas concentration, mainly CO_2 [11]. The measurement of the atmospheric CO_2 concentrations for the last 250 years illustrates its increase from 270 to more than 370 ppm. Experts report that carbon dioxide emissions account for about two third of the potential global warming [12]. One of the effective solutions for decreasing the emission of CO_2 is direct capturing and storing it in deep geological formations, which is known as carbon capture and storage (CCS) [13]. The injection of carbon dioxide into natural gas reservoirs is a promising technique for reducing anthropogenic greenhouse gas emission and increasing the ultimate recovery of natural gas [14-15].

Several studies have been reported on the numerical simulation and investigation of the CO_2 storage process in oil and gas reservoirs with the aim of improving recovery especially to discuss the displacement process [2, 9, 14-22].

In this work, the process of carbon dioxide (CO_2) injection into a water-drive gas condensate reservoir was studied. The aim of this process is sweeping reservoir base gas and the reduction of water encroachment into reservoir. The reservoir is located in the south of Iran and contains condensate with an active aquifer. This process can deplete the base gas before water entrapment. Moreover, the injection of CO_2 stores a large amount of CO_2, which is interested from an environmental point of view these days.

Reservoir Description

The reservoir studied in this work is located in the south of Iran and contains gas condensate. It has IGIP of 1.80 trillion SCF (50.98 billion SCM). The reservoir is represented using an 84×78×19 compositional simulated model and has an area of 4047.6 acre (16.37 km^2) and an average thickness of 224.2 m. The average porosity of the reservoir rock is 10.63% with an average net to gross (NTG) ratio of 0.823. Table 1 represents the general data of the reservoir. It is composed of single porosity carbonate rock and its relative permeability curves were modeled using Corey method [23]. The reservoir was sealed from the top by an evaporate formation, but the boundaries of the reservoir were permeable. This anticline has the lithology of mainly limestone and 4 vertical zones with heterogeneous rock properties (porosity, permeability etc.). From top of the reservoir, the second zone has weaker reservoir properties (permeability) than the others.

Table 1: The reservoir general data.

Parameter	Unit	Value
Average porosity	%	10.63
Average horizontal permeability	md	4.98
Average vertical permeability	md	0.5726
Average NTG	-	0.823
Initial pressure	bar	270.8
Initial temperature	°C	73
Reservoir area	acre	4047.6
Average thickness	m	224.2
Depth of water/oil contact (WOC)	m	2750
Reference depth	m	2750
Reservoir top depth	m	2486

The reservoir has 4 vertical production wells, and 2 horizontal injection wells were proposed for EGR scenario. The production wells were perforated in the whole reservoir thickness at a distance of water/oil contact. The horizontal part of the injection wells were perforated with a length of about 3.8 km, and the average horizontal distance between the injection and vertical wells is about 1.7 km. Figure 1 depicts the 3D view of the reservoir and its wells. The reservoir fluid was characterized using three-parameter Peng-Robinson equation of state (EOS). The composition of the reservoir fluid is represented in Table 2.

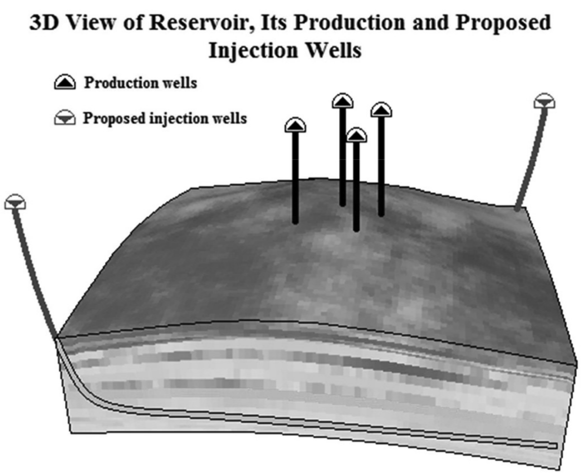

Figure 1: 3D view of reservoir model and their wells.

Table 2: The composition of reservoir fluid.

Component	Mole Fraction (%)
Nitrogen (N_2)	9.69
Methane (CH_4)	85.14
Ethane (C_2H_6)	1.66
Propane (C_3H_8)	0.94
Heavy components	2.57

This reservoir has a bottom-up aquifer which is modeled using Carter-Tracy aquifer model. Table 3 shows the aquifer properties.

Table 3: The aquifer properties.

Property	Unit	Value
Porosity	%	30
Permeability	md	400
Water compressibility	bar^{-1}	0.000155
External radius	m	400
Thickness	m	100
Angle of influence	°	360
Top limit	m	-2750

Production and Injection Scenarios

In this work, three cases have been studied in order to investigate the effect of aquifer activity on cumulative gas and condensate production. In the first case (Case I), the effect of aquifer on reservoir was omitted by deactivating it. It is crucial to note that this case is an imaginary scenario and does not happen in reality. This case is similar to up-dip production in an infinite water production condition to cancel the aquifer effects. The production time is 9 years with a constant bottomhole pressure of 80 bar. The water-cut limitation of 20% controls the water production of the reservoir. In the second case (Case II), the production process by depletion scenario was studied. This case is the base scenario of the production in this reservoir. The comparison of the Case I and Case II illustrates the effect of aquifer activity on gas and condensate production. Finally, in the last case (Case III), the CO_2 injection process was simulated. In this case, the injection scenario was begun at the first year of production at a rate of 4 million standard cubic meters per day (MMSCMD) per each injection wells. The injection process was continued until the pressure reached the 90% of the reservoir initial pressure for lowering the risk of caprock fracturing. The objective of this case was investigating the effect of CO_2 injection on the reduction of aquifer water encroachment and on the increase of hydrocarbon production. The production conditions of the two last cases are the same as the first one.

RESULTS AND DISCUSSION

In this work, the process of CO_2 injection into a water-drive gas condensate reservoir was studied. The aim of this process is sweeping reservoir base gas and the reduction of water encroachment into reservoir. This process can deplete the base gas in the rock pores before water entrap them. Furthermore, the injection of CO_2 stores a large amount of CO_2 which is interesting from an environmental point of view.

Comparison of Gas and Condensate Production

Comparison of hydrocarbon recoveries shows the effectiveness of the enhanced hydrocarbon recovery technique. Figure 2 compares the cumulative gas production of Cases I, II, and III. This figure shows that aquifer activity (Case II) decreases the cumulative gas production in comparison with inactive aquifer (Case I) by 21%. It also illustrates that injecting CO_2 has a significant effect on cumulative gas production and increases the gas recovery as an inactive aquifer case.

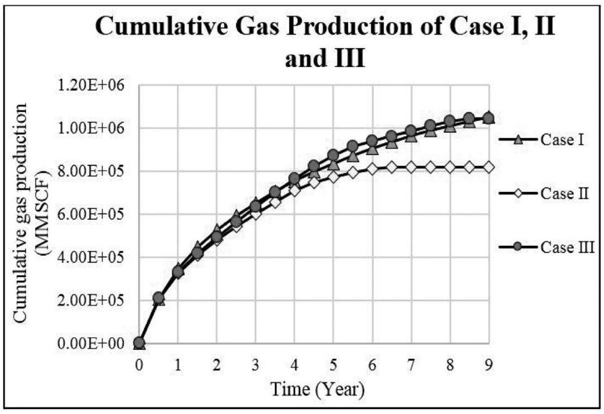

Figure 2: Comparison of cumulative gas production of Cases I, II, and III.

The comparison of cumulative condensate production of three cases is shown in Figure 3. This figure demonstrates that encroachment of water in the reservoir increases cumulative condensate production (cumulative condensate production of Case I is about 0.87 times of Case II). Considering this fact, it can be concluded that aquifer activation has positive effects on condensate production, but this point should be considered that the amount of the reduction in gas production is economically higher than the amount of the rise in condensate production. Therefore, the water movement into the reservoir zone causes profit loss, especially in this case. Moreover, this figure illustrates that the injection of CO_2 in Case III increases the condensate production by 58 and 82% in comparison with Cases II and I.

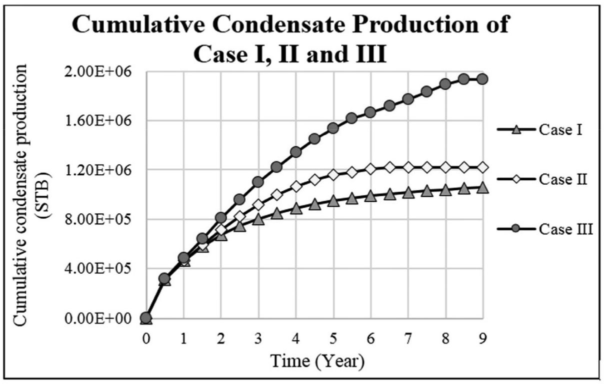

Figure 3: Comparison of cumulative condensate production of Cases I, II, and III

Actually, the condensate production increase in Cases II and III were happened due to pressure maintenance of these cases. Figure 4 depicts the reservoir pressure curve of three cases in which the pressure maintenance process of the Case III is demonstrated.

In gas condensate reservoirs, by declining the reservoir pressure to the first dew point, gas condenses in porous media. This process decreases the condensate content of producing gas, which is projected in condensate-gas ratio (CGR). Hence, maintaining the pressure in the water-drive gas condensate reservoirs has another advantage of the inhibition of condensing gas in pay zone. Comparing Figure 2 and Figure 3 shows that the CGR of Case I decreases gradually with a pressure decline from 1.5 to 1.0 STB/MMSCF although the CGR's of Case II and III are constant and equal to about 1.5 STB/MMSCF.

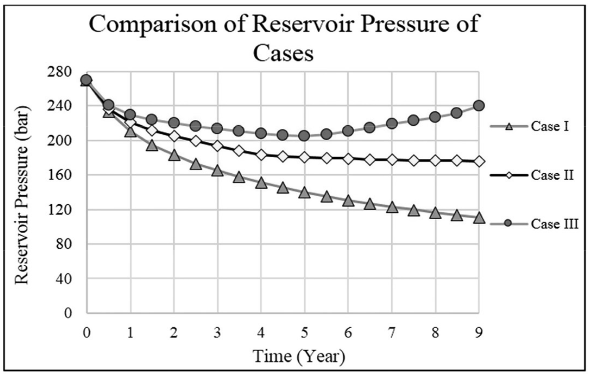

Figure 4: Comparison of reservoir pressure of Cases I, II, and III.

CO_2 Production and Injection of Case III

The amounts of injecting and reproducing CO_2 are crucial in the case of CCS. Huge reproduction of injected CO_2 may fail the process due to low net CO_2 sequestration. Figure 5 depicts the cumulative CO_2 injection of Case III in million tons. It also shows the CO_2 production in terms of the weight percent of CO_2 production to injection. As it is clear in this figure, the amount of CO_2 production is zero until the second years. The percent of CO_2 production to injection is about 0.0003 in the worst condition, which is negligible. This fact demonstrates that a huge amount of CO_2, i.e. 47.3 million tons in 9 years, can be sequestered using this process.

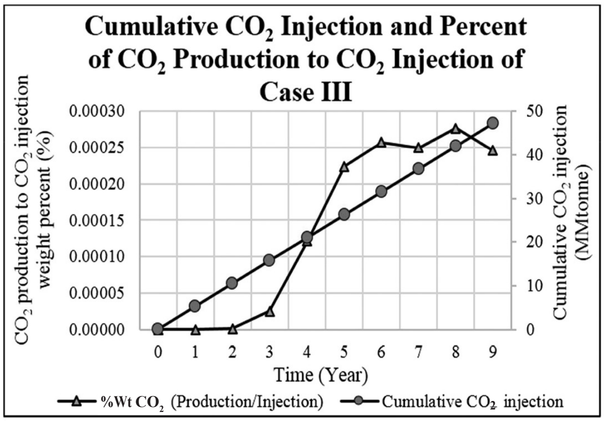

Figure 5: Cumulative CO_2 injection and the percent of CO_2 production to CO_2 injection of Case III.

Figures 2-5 illustrate that the injection of CO_2 in a gas condensate reservoir under water-drive production enhances the amount of gas and condensate recovery and profit consequently. This process stores a large amount of CO_2 with negligible CO_2 production as an interesting process for environmental experts. The injection of carbon dioxide sweeps the reservoir base gas before water invades the porous media. In fact, the injection of CO_2 enhances gas recovery and maintains the reservoir pressure, so it prevents water movement because of low pressure drawdown in the reservoir.

Comparison of Cumulative Water Influx of Cases II and III

Figure 6 compares the cumulative water influx of aquifer for Cases II and III, which approves our last conclusions. As can be seen in this figure, the volume of water influx of aquifer to reservoir in Case II is 1.5 times of Case III. This result shows the effect of CO_2 plume on water movement in reservoir.

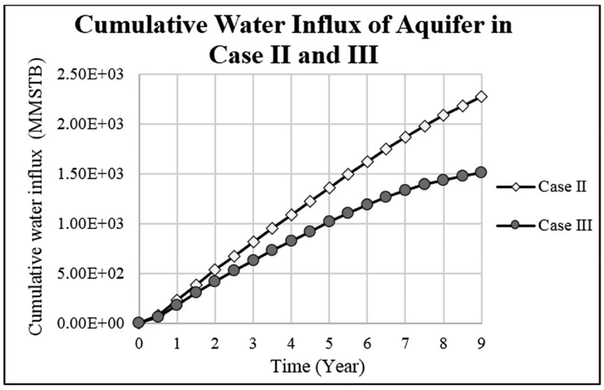

Figure 6: Comparison of cumulative water influx of aquifer for Cases II and III.

Figure 7 shows the profile of methane and carbon dioxide mole fraction of Case III and water saturation of Cases II and III versus depth. This figure demonstrates that carbon dioxide plays two roles in this process. First, the mole fraction of CO_2 and CH_4 illustrates that carbon dioxide sweeps the base gas to the production wells effectively. Second, comparing the profile of the water saturation of Case I and II shows that a CO_2 plume was composed above the aquifer, which controls the water encroachment into the reservoir. Figure 8 depicts the 3D view of CO_2 propagation in the reservoir. In this figure, the CO_2 mole fraction can be seen in the left hand side for 3 years (at end of 3rd, 6th, and 9th years). For a better understanding of the CO_2 movement, the CO_2 plume was depicted in the left hand side, which shows the propagation of CO_2 front to the production wells and above aquifer.

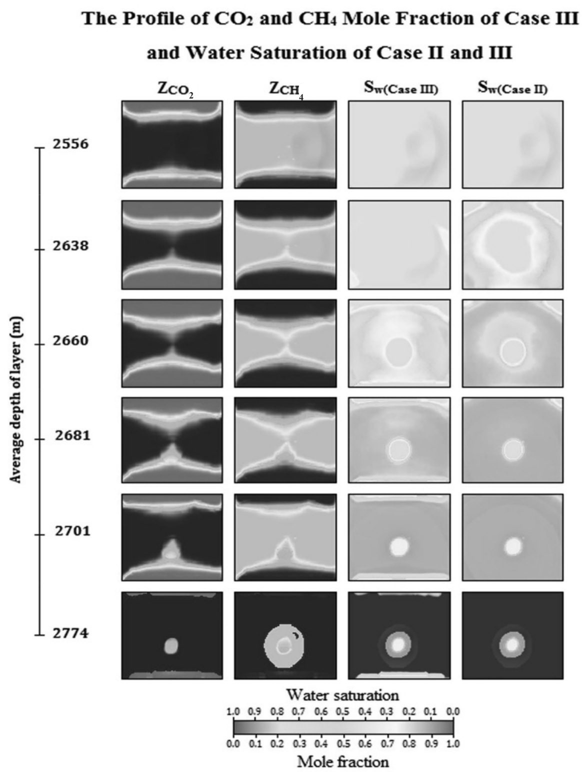

Figure 7: The profile of CO_2 and CH_4 mole fraction of Case III and water saturation of Cases II and III.

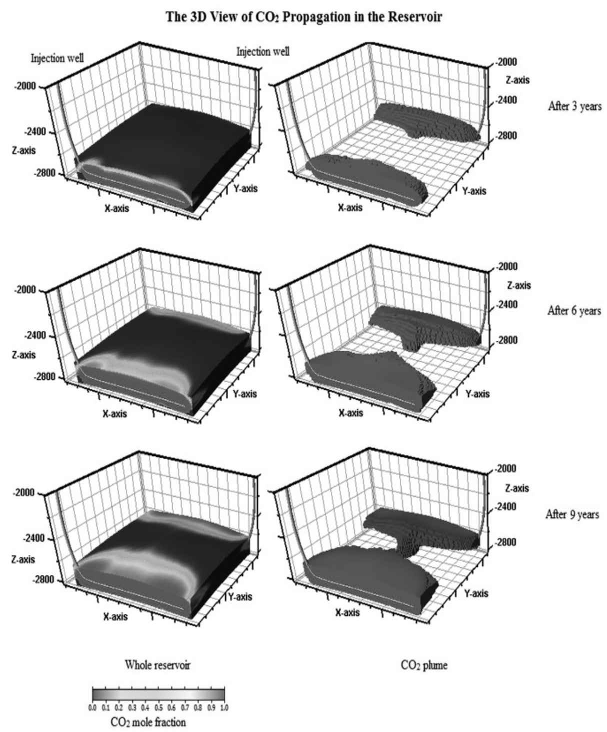

Figure 8: The 3D view of CO_2 propagation in the reservoir.

Investigating the Effect of Uncertain Reservoir Parameters on CO_2 injection Process

Uncertainties, especially in geological parameters, are always present and can be significant if associated with field development. These uncertainties could be perceived by geologists and engineers to exist in the available data [24]. The uncertainty analysis in the current case can decrease the risk of the process and show the range of recovery changes in Case III. For this aim, different scenarios have been designed to capture the uncertainty effects. Four parameters, i.e. porosity (Φ), permeability (K), the ratio of vertical to horizontal permeability (K_h/K_v), and net to gross ratio (NTG), were considered as uncertain parameters. Because of time consuming simulation runs, the partial factorial experimental design (2^{k-1}) was conducted to investigate the effect of uncertainty [25]. Table 4 shows the designed simulation cases run to capture uncertainty. The expression (-1) and (+1) shows the amount of parameters in their minimum and maximum levels.

Table 4: The partial factorial experimental design (2^{k-1}) runs.

Run number	Φ	K	K_h/K_v	NTG
1	-1	-1	-1	-1
2	+1	-1	-1	+1
3	-1	+1	-1	+1
4	+1	+1	-1	-1
5	-1	-1	+1	+1
6	+1	-1	+1	-1
7	-1	+1	+1	-1
8	+1	+1	+1	+1

Figures 9 and 10 show the comparison of gas and condensate recovery for the chosen runs in Table 4. These figures illustrate that the injection scenario is effective with different levels of uncertainty. It is notable that the aim of these figures are not discussing about the effect of different parameters on the process, but the purpose of this section is showing that uncertainties of the reservoir parameters do not affect the success of the process. The process (Case III) in the worst case of uncertainties is effective in comparison to the other cases (Case I and II). Figure 9 illustrates the 4 and 46% recovery increase in comparison to Case II in the worst and base cases. This is about 31 and 78% for condensate recovery as can be seen in Figure 10.

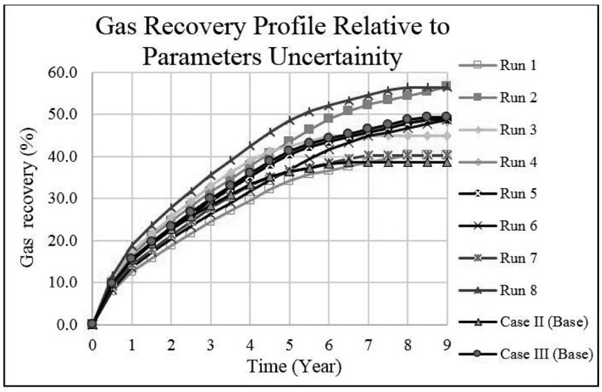

Figure 9: The gas recovery profile relative to the uncertainty of different reservoir parameters.

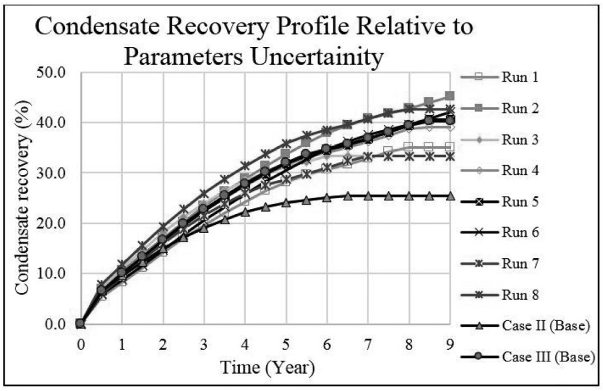

Figure 10: The condensate recovery profile relative to the uncertainty of different reservoir parameters.

CONCLUSIONS

In this work, the process of the injection of CO_2 to enhance gas recovery and control the water invasion of a water-drive gas condensate reservoir, located in the south of Iran, was studied. Considering this work, the following results can be concluded:

- The injection of CO_2 in a water-drive gas condensate reservoir increases the gas and condensate recovery by 27 and 58% respectively with negligible CO_2 production. This is because CO_2 injection prevents the encroachment of water by filling the pore volumes and effective sweeping the reservoir base gas. The uncertainty analysis of the reservoir parameters shows that in all the levels of uncertainty, the process can be beneficial.

- The injection of CO_2 in this reservoir has two significant advantages. First, it increases the recovery of gas and condensate, which raises the profit of the process. Second, it can sequester a huge amount of CO_2 (about 47.3 million tons), which is interesting from an environmental point of view.
- The pressure maintenance of the reservoir by injecting the CO_2 controls the water encroachment into the reservoir. Moreover, it prevents declining the pressure under reservoir fluid dew point and sustains the CGR constant, which results in a high recovery of condensate.

NOMENCLATURE

md	Millidarcy
M	Thousand
MM	Million
SCF	Standard Cubic Feet
SCM	Standard Cubic Meter
STB	Stock Tank Barrel

REFERENCES

1. Lee W. J. and Wattenbarger R. A., "Gas Reservoir Engineering," SPE Textbook Series, **1996**.
2. Turta A. T., Sim S. S. K., Singhal A. K., and Hawkins B. F., "Basic Investigations on Enhanced Gas Recovery by Gas-Gas Displacement," *Journal of Canadian Petroleum Technology*, **2008**, *47*(10), 39-44.
3. Mckay B. A., "Laboratory Studies of Gas Displacement from Sandstone Reservoirs Having a Strong Water Drive," *APEA Journal*, **1974**, 189-194.
4. Bassiouniz Z., "Enhanced Recovery from Water-Drive Gas Reservoirs," *Rudarsko-Geolosko-Naftni Zbornik*, **1990**, *2*, 151-159.
5. Holtz M., "Residual Gas Saturation to an Influx: A Calculation Method for 3-D Computer Reservoir Model Construction," SPE 75502, **2002**.
6. Batycky J., Irwin D., and Fish R., "Trapped Gas Saturation in Leducage Reservoirs," *Journal of Canadian Petroleum Technology*, **1998**, *37*(2), 32-39.
7. Chesney T. P., Lewis R. C., and Trice M. L., "Secondary Gas Recovery from a Moderately Strong Water-Drive Reservoir: A Case History," *JPT*, **1982**, *34*(9), 2149-2157.
8. Ali F., "Importance of Water Influx and Waterflooding in Gas Condensate Reservoir. Department of Petroleum Engineering and Applied Geophysics," Norwegian University of Science and Technology (NTNU), **2014**, 9.
9. Sim S. S. K., Brunelle P., Turta A. T., and Singhal A. K., "Enhanced Gas Recovery and CO_2 Sequestration by Injection of Exhaust Gases from Combustion of Bitumen," SPE 113468, **2008.**
10. Al-Hashami A., Ren S. R., and Tohidi B., "CO_2 Injection for Enhanced Gas Recovery and Geo-Storage: Reservoir Simulation and Economics," SPE 94129, **2005**.
11. Blyton C. A. J., "Kinetic of CO_2 Dissolution in Brine: Experimental Measurement and Application to Geologic Storage," The University of Texas at Austin, **2012**, 18-22.
12. Cakici M.D., "Co-optimization of Oil Recovery and Carbon Dioxide Storage," M. Sc. Thesis, Stanford University, **2003**, 1-2.
13. Faiz M. M., Saghafi A., Barclay S. A., Sherwood L. S. N. R., and Whitford D. J., Evaluating Geological Sequestration of CO_2 in Bituminous Coals: The Southern Sydney Basin, Australia as a Natural Analogue," *International Journal of Green-house Gas Control*, **2007**, *1*, 223-235.
14. Jikich S. A., Smith D. H., Sams W. N., and Bromhal G. S., "Enhanced Gas Recovery (EGR) with Carbon Dioxide Sequestration: A Simulation Study of Effects of Injection Strategy and Operational Parameters," SPE 84813., **2003**.
15. Oldenburg C. M., "Carbon Sequestration in Natural Gas Reservoirs: Enhanced Gas Recovery and Natural Gas Storage Proceeding," Tough Symposium, California, **2003**.
16. Forest T., "CO_2 Enhanced Oil Recovery in Strong

Water-Drive Reservoirs. Department of Petroleum Engineering and Applied Geophysics," Norwegian University of Science and Technology (NTNU), **2012.**

17. Sim S. S. K., Turta A. T., Singhal A. K., Hawkins B. F., and Council A. R., "Enhanced Gas Recovery: Factors Affecting Gas-Gas Displacement Efficiency," *Journal of Canadian Petroleum Technology*, **2009**, *48*(8), 49-55.
18. Kühn M., Förster A., Grobmann J., Meyer R., et al., "CLEAN: Preparing for a CO_2-based Enhanced Gas Recovery in a Depleted Gas Field in Germany," *Energy Procedia*, **2011**, *4*, 5520-5526.
19. Secklehner S., Arzmüller G., and Clemens T., "Tight Ultra-deep Gas Field Production Optimization – Development Optimization and CO_2 Enhanced Gas Recovery Potential of the Schoenkirchen Uebertief Gas Field," Austria. SPE 130154, **2010.**
20. Wei X. R., Wang G. X., Massarotto P., Golding S. D., et al., "Numerical Simulation of Multicomponent Gas Diffusion and Flow in Coals for CO_2 Enhanced Coalbed Methane Recovery," *Chemical Engineering Science*, **2007**, *62*, 4193–4203.
21. Zangeneh H., Jamshidi S. and Soltanieh M., "Coupled Optimization of Enhanced Gas Recovery and Carbon Dioxide Sequestration in Natural Gas Reservoirs: Case Study in a Real Gas Field in the South of Iran," *International Journal of Greenhouse Gas Control*, **2013**, *17*, 515-522.
22. Zangeneh H., Safarzadeh M. A., and Asgari A. A., "Carbon Dioxide Injection to Control Water Encroachment in Water-Drive Gas Condensate Reservoirs. TP4-23," International Gas Union (IGU) Conference, Denmark, **2014.**
23. Ahmed T., "Handbook of Reservoir Engineering," Gulf Professional Publishing, Texas, **2000**, 292-293.
24. Mesdour R., Ramsey L., and Aly A., "Optimizing Development Well Placements within Geological Uncertainty Utilizing Sector Model," SPE 12847, **2010.**
25. Montgomery D. C., "Design and Analysis of Experiments," Fifth Edition, John Wiley & Sons Inc, **2001**, 303-347.