2452 *Ind. Eng. Chem. Res.* **2006,** *45,* 2452−2456

Effect of Operational Parameters on Carbon Dioxide Storage Capacity in a Heterogeneous Oil Reservoir: A Case Study

Koorosh Asghari,* Adal Al-Dliwe, and Nader Mahinpey

University of Regina, 3737 Wascana Parkway, Regina, Saskatchewan, Canada, S4S 0A2

Underground storage of carbon dioxide (CO_2) is attracting considerable interest worldwide as a means of avoiding continued release of CO_2 from anthropogenic sources. Here, a heterogeneous oil reservoir in Alberta, Canada, was chosen for evaluating the potential use of this site for storage of a mixture of 90% CO_2 + 10% H_2S produced from a nearby gas plant. This reservoir produces 34° API light oil from a pinnacle reef, which is a carbonate reservoir with a depth of 4800 ft (1441 m). A fully compositional, three-dimensional (3-D) reservoir simulation model, CMG-GEM, was used to simulate various operational conditions, study the reservoir and fluid characteristics, and investigate the amount of CO_2 stored and oil recovered. The results of this study show that a combination of two vertical injectors and one horizontal producer optimizes the incremental oil recovered and amount of CO_2 stored. The procedure developed in this study, and the findings of this study, can be used as guidelines for designing and implementing any future CO_2 injection and storage project in similar oil reservoirs.

Introduction

The geological storage of CO_2 requires transporting the CO_2 stream that would otherwise have been emitted, compressing and then injecting it into a deep geological formation, where it will be safely stored. The geological formations in which it will most likely be safe to store CO_2 include active and depleted hydrocarbon reservoirs, coal seams, and deep aquifers. Among these options, injecting CO_2 in partially depleted oil reservoirs leads to additional oil recovery and economic benefit, while storing large volumes of CO_2.

Depending on the type of the reservoir and the extent of heterogeneities, different injection and production schemes must be implemented.[1] Therefore, proper modeling of the reservoir structure and heterogeneities is a key to ensuring the success of any CO_2 injection and storage project. However, in many cases, no reliable data exist for modeling these storage sites (e.g., in the province of Alberta, Canada, ∼60% of the oil pools are single-well pools[2]).

The injection and production rates have important roles in controlling the movement of the miscible CO_2-oil front in the reservoir and preventing the formation of viscous fingers.[3] Also, reservoir pressure and temperature have great effects on recovery and CO_2 storage. At constant pressure, the density of CO_2 decreases as the temperature increases, which is working unfavorably against storing large amounts of anthropogenic CO_2.[4] In addition, the operating pressure must be greater than the minimum miscibility pressure (MMP) to form a miscible front between the CO_2 and the oil. Operating below the MMP results in lower oil recovery, because of immiscible displacement, which leads to lower CO_2 storage capacity. This reduced CO_2 storage capacity is due to two factors: (i) lower oil recovery leads to lesser void pore space available for storing CO_2; and (ii) lower pressure leads to larger molar volume of the injected gases, while, at elevated pressures, CO_2 is denser and, therefore, a larger volume of the injected gas can be stored in reservoir. However, working at higher pressures is limited by the compression costs and mechanical strength of the reservoir rock.[5] The presence of high-permeability channels, directional permeability, excessive horizontal-to-vertical permeability ratio, fractures and faults, and shale barriers complicate prediction of the performance of the CO_2 storage project. Timing for starting CO_2 injection also affects the ultimate oil recovery and the final storage capacity. Introduction of water into the reservoir, for improving oil recovery, can adversely impact the space available for storing CO_2.[6] Impurities in the CO_2 injection stream affect the process efficiency, depending on the types and concentrations of impurities. The presence of H_2S and intermediate hydrocarbons, such as C_3 or C_4, reduces the MMP and improves the displacement efficiency.

Because of the wide variety of parameters that can influence the outcome of CO_2 storage projects in underground oil reservoirs, reservoir simulation has gained wide popularity as a powerful tool to characterize the reservoir and design and predict the ultimate storage capacity of any project involving geological storage of CO_2.

This paper describes the steps taken to study an actual oil reservoir located in Alberta, Canada, for CO_2 storage and enhanced oil recovery purposes. This oil field, Zama Keg River F Pool, is located in northern Alberta and was discovered in 1967. A fully compositional reservoir simulation model, CMG-GEM, from the Computer Modeling Group, was used to model the reservoir, to determine the amount of CO_2 stored at the end of the enhanced oil recovery (EOR) period, and to find the influence of different operational parameters on oil production.

Note that the purpose of this study is not to determine the long-term fate of CO_2, but rather to investigate the effect of various operational and reservoir parameters on CO_2 storage capacity in this reservoir at the end of the CO_2 injection period.

Reservoir History

Zama Keg River F Pool is a heterogeneous pinnacle reef located in Zama Basin, in North Alberta. The initial oil production from this reef was started in April 1967. The reef has an average depth of 4800 ft (1441 m), initial pressure of 2100 psi (14470 kPa), and temperature of 160 °F (71 °C). It reached the bubble point pressure of 1275 psi (8786 kPa) less than one year after the production started and continued to

---

* To whom correspondence should be addressed. Tel.: (306) 585-4612. Fax: (306) 585-4855. E-mail: Koorosh.Asghari@uregina.ca.

10.1021/ie050572y CCC: $33.50

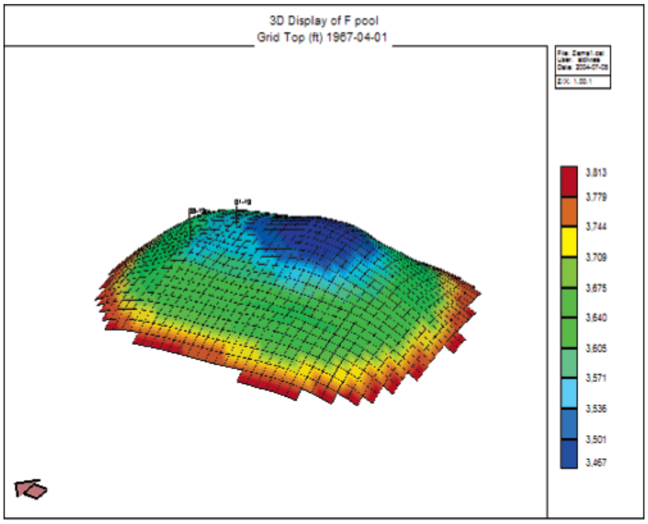

Figure 1. Three-dimensional (3D) display of the reservoir model for the Zama Keg River F Pool.

produce below the bubble point pressure until early 1987, when water injection into this field started. Because of economical considerations, oil production from this reservoir was stopped in May 2003.

Reservoir Simulation and History Matching

The reservoir under study is a heterogeneous carbonate reef with a thick oil column of 81 m that spans an area of more than 34 acres (137 600 m^2), which has a dome shape, as shown in Figure 1. The reef has an average depth of 1450 m, initial pressure of 2100 psi (14,470 kPa), and temperature of 160 °F (71 °C). The geological model for this reservoir contains a total of 49 950 grid blocks [(30 blocks in the *X*-direction) × (37 blocks in the *Y*-direction) × (45 layers in the *Z*-direction)]. The average size of each of the grid blocks is 25 ft × 25 ft × 6 ft (7.57 m × 7.57 m × 1.8 m) (dimensions given in the *X*-, *Y*-, and *Z*-directions, respectively). This geological model (i.e., static model) was provided by Apache Canada, Ltd., and was exported to the reservoir simulator, CMG-GEM, successfully. The final dynamic model used for simulation studies included the aforementioned geological model, and the relative permeability, fluid properties, and pressure−volume−temperature (PVT) data entered directly into CMG-GEM.

Traditionally, the dynamic model for the reservoir is tuned by comparing the actual past production data from the field with the production data calculated by the model. This procedure is called “history matching”. This technique was used in this study to generate a reliable dynamic reservoir model, before predictions about CO$_2$ storage are made.

The phase behavior for the mixture of the injected gas and reservoir oil was represented by an eight-pseudo-component Peng−Robinson equation of state (EOS) in CMG-GEM. Figure 2 presents the results for the history matching, using the model developed during this study. The red line indicates the values calculated through simulation, whereas the blue line represents the actual data available for this field. The actual production data from this reservoir are in good agreement with the values calculated by this model. Hence, this model was used to predict the amount of CO$_2$ stored in this reservoir at the end of the EOR period.

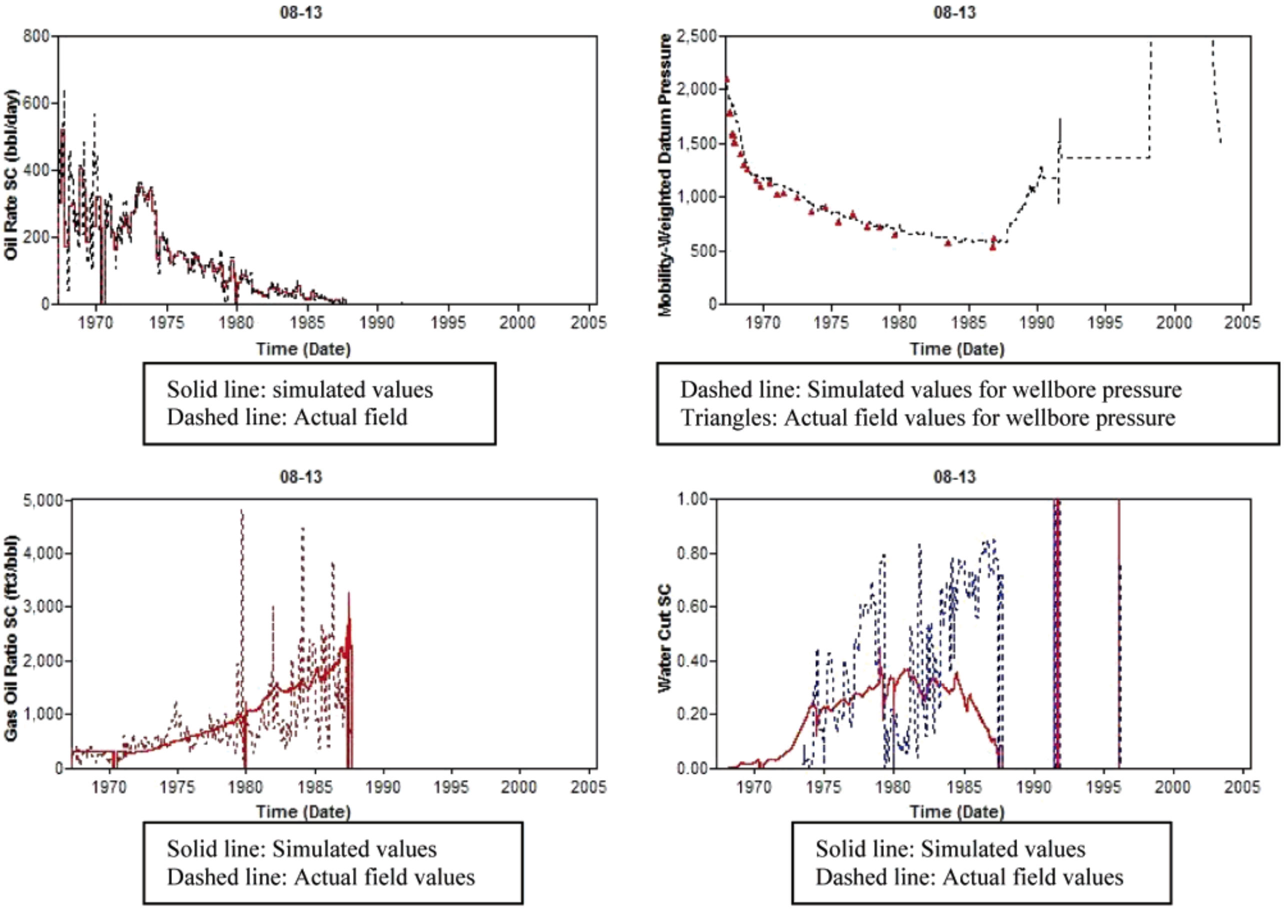

Figure 2. History match results; actual versus simulated (rates and pressure).

Table 1. Current Conditions and Constrains Applied for Prediction Scenarios

parameter	value
current reservoir pressure	1450 psi
reservoir parting pressure	4350 psi
available gas for injection	170 tonnes/day (3.4 MMscf/day)
gas stream purity	10% H_2S−90% CO_2
starting date for gas injection	June 1, 2003
injection period	17 years
minimum operating pressure	2500 psi
maximum injection pressure	4300 psi
liquid production rate	1500 bbl/day

CO_2 Storage Capacity and Enhanced Oil Recovery (EOR) Operational Conditions, Constraints, and Results

After the model was validated through the history matching process, it was used to predict the CO_2 storage in the Zama Keg River F Pool reservoir. A total of 170 tonnes/day (3.4 MMscf/day) of acid gas (90% CO_2 + 10% H_2S) is available from and imposed by a nearby gas plant for injection purposes. The presence of H_2S reduces the MMP: the higher the H_2S concentration, the lower the MMP. Two major pressure constraints were imposed for the gas injection operations. First, for all prediction scenarios except one, the reservoir operating pressure was set to a minimum of 2500 psi (17228 kPa), to ensure miscible displacement (MMP = 2500 psi), and the maximum injection pressure was set at 50 psi (345 kPa) below the formation parting pressure of 4350 psi (29 976 kPa). The injected CO_2 will be at a supercritical state under the injection conditions of 2500 psi and 160 °F. At a supercritical state, CO_2 has higher density, which leads to more CO_2 being stored in the reservoir, compared to CO_2 in the gaseous state. Various predictive CO_2 storage scenarios were developed and tested for 17 years of injecting CO_2 in this reservoir, beginning in 2003 and ending in 2020. Effects of different operational parameters on CO_2 storage were studied. These parameters included; production and injection rates, injection gas composition, direction of displacement, mode of injection, and the timing of starting gas injection. A summary of the reservoir conditions and the constraints applied is presented in Table 1.

Although the nature of the production process will have an impact on the ultimate storage capacity, in this paper, the effect of mechanisms, such as reservoir compaction and/or the potential storage of CO_2 in the aquifer, have not been considered.

CO_2 Storage Study 1. Effect of Horizontal Wells on CO_2 Storage. Horizontal wells improve the sweep efficiency, maintain the reservoir pressure above its MMP with low injectivity requirements, and enhance the productivity.[7−9] In this scenario, CO_2 was injected in a horizontal injection well located at the top of the reservoir while oil was produced from a second horizontal well located at the bottom of the reservoir (i.e., the displacement direction was from top to bottom). The total liquid production was set at 1500 bbl/day, as per Table 1. Figure 3 presents the amount of oil produced, as well as CO_2 and H_2S stored for this field beginning at June 1, 2003 for 17 years of gas injection. Unretained CO_2 and H_2S return to the surface, where they are separated from the produced oil at the surface facilities. This separated gas is either re-injected into the reservoir or vented into the atmosphere. Nevertheless, this configuration shows high sweep efficiency with the incremental additional produced oil of 0.87 MMSTB and a total amount of gas (CO_2 plus H_2S) stored of 0.398 Mt.

CO_2 Storage Study 2. Combination of Vertical and Horizontal Wells. In this scenario, the effect of a combination of two vertical wells, as injectors, and one horizontal well, as a producer, on the storage of CO_2 was investigated. Because the total gas available for injection was 3.4 MMscf/day (see Table 1), 1.7 MMscf/day of gas was injected into each vertical injection well. To establish a top-to-bottom displacement path, the horizontal production well was located at the bottom of reservoir. Figure 4 shows the results for oil produced and CO_2 stored in the reservoir. Overall, the additional oil recovered was 1.04 MMSTB, and the sour gas (CO_2 + H_2S) retained was 0.424 Mt.

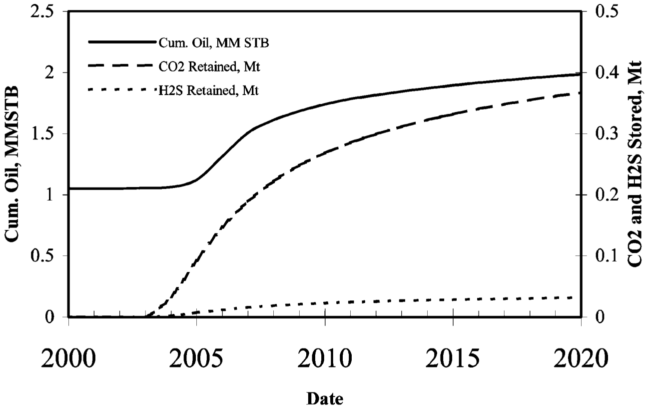

Figure 3. Oil production performance; CO_2 and H_2S retained as a function of time for horizontal wells as injection and production wells.

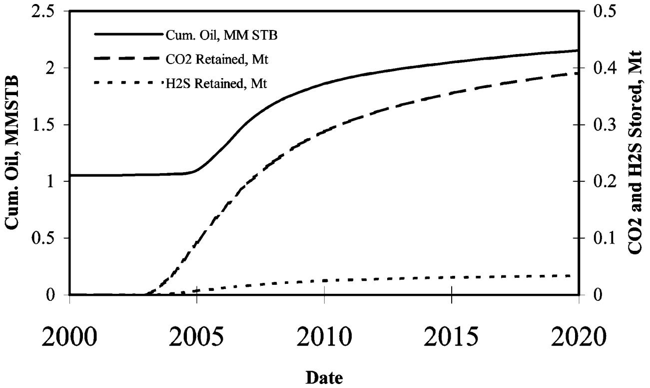

Figure 4. Oil production performance; CO_2 and H_2S retained as a function of time for two vertical well as injectors and one horizontal well as a producer.

CO_2 Storage Study 3. Effect of Production Rates. Several forecast scenarios with different production rates were performed. The objective of this study was to investigate the effect of higher and lower withdrawal rates on the amount of CO_2 stored. For the case with two horizontal wells, CO_2 storage study 1, liquid rates of 1000, 1500, and 2000 bbl/day were tested. The results of this analysis are presented in Figure 5, where it is clear that changing the production rate has no noticeable effect on the total gas stored (i.e., 0.398 Mt for both the 1500 and 2000 bbl/day cases and 0.399 Mt for the 1000 bbl/day case).

CO_2 storage study 2 is characterized by the fact that the injected gas is introduced into the reservoir through two vertical wells. For this case, two production rates of 1500 and 2000 bbl/day were tested in addition to the base case of 1000 bbl/day. The results for the amount of gas stored are presented in Figure 6. Once again, the results indicate that the production rate does not have any effect on the final amount of gas stored in this reservoir.

CO_2 Storage Study 4. Effect of H_2S Concentration. The presence of H_2S in the injected CO_2 stream decreases the MMP and enhances the performance of miscible displacement in the reservoir. Hence, it was decided to investigate the effect of H_2S

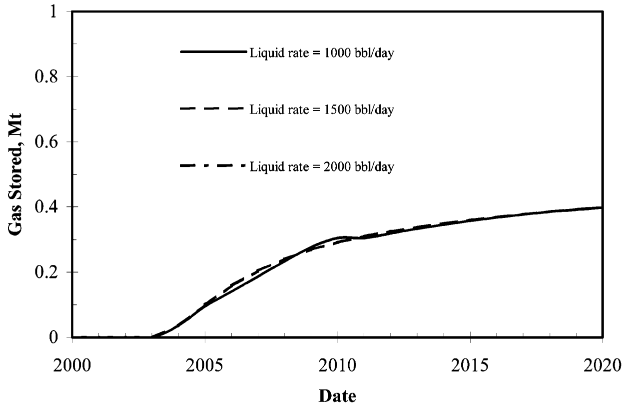

Figure 5. Effect of production rate on the total gas storage capacity for CO_2 storage study 1.

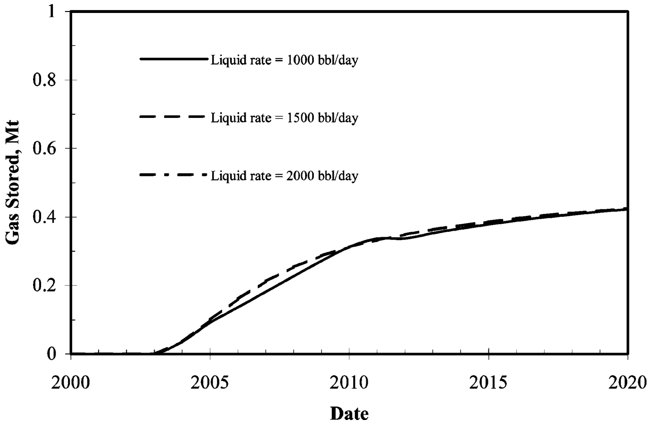

Figure 6. Effect of production rate on the total gas storage capacity for CO_2 storage study 2.

concentration on the total gas stored in this reservoir. For this purpose, three streams of 100% CO_2, 90% CO_2−10% H_2S, and 80% CO_2−20% H_2S were examined. For all simulation runs, the amount of gas stored in reservoir increases with higher concentrations of H_2S, as expected. Overall, the lower MMP leads to higher gas storage capacity in the reservoir. Note that, for the field under study, the composition of the gas stream is fixed at 10% H_2S and 90% CO_2 by the supply source.

CO_2 Storage Study 5. Effect of Direction of Displacement. In all the previous cases, CO_2 was injected from the top of the reservoir and oil was produced from the bottom of the reservoir. In this set of simulation runs, CO_2 was injected in an horizontal well located at the bottom of the reservoir while oil production occurred from another horizontal well located at the top of the formation. The results indicated that the total gas stored was not improved because of the new upward displacement path. Hence, it was concluded that the upward injection of CO_2 does not have any positive effect on increasing the amount of gas stored in this reservoir.

CO_2 Storage Study 6. Early Implementation of CO_2 Injection (Effect of Timing). This section presents the results for quantifying the ultimate gas storage capacity if CO_2 injection had been started in 1968 instead of 2003. A comparison of the early implementation of CO_2 injection with CO_2 storage study 1 (the first two columns of Figure 7) and the early implementation of CO_2 injection with CO_2 storage study 2 (the second two columns of Figure 7) indicates an increased storage of 0.417 and 0.468 Mt, respectively. Generally, early implementation of CO_2 flooding leads to higher oil recovery, which, in turn, provides more pore space in the reservoir for CO_2 storage.

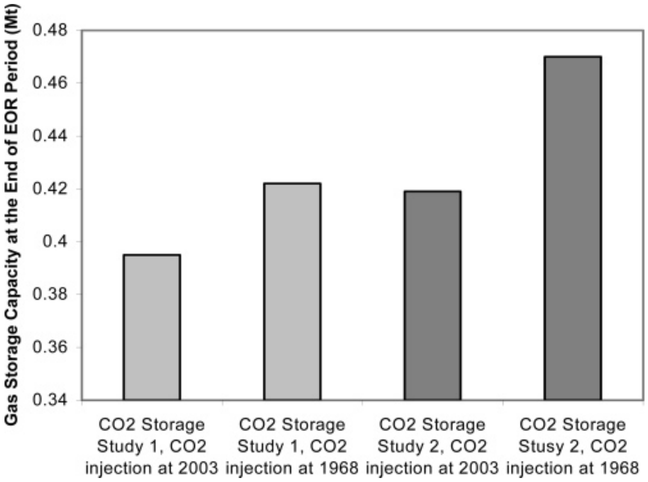

Figure 7. Effect of early implementation of CO_2 injection on the ultimate gas storage capacity of the reservoir.

Utilization Factor. The goal of this study was to determine ways for optimizing gas storage capacity in the Zama Keg River F Pool. The International Energy Agency (IEA) uses a utilization factor of 0.3 tonnes/STB (6000 scf/STB) to calculate the global storage capacity of CO_2 in oil reservoirs.[10] The IEA utilization factor represents the calculated average net utilization factors of 16 CO_2 EOR projects in the United States. For the CO_2 storage project presented in this paper, the net utilization factor (i.e., recycled gas is not included) is 0.41 tonnes/STB. Hence, it is concluded that, in Zama Keg River F pool, by selecting the suitable operating conditions, the CO_2 storage can be achieved with utilization factors greater than IEA standards.

Conclusions

The following conclusions are drawn based on the results of this study:

(1) A successful history matching for the Zama Keg River F Pool was conducted.

(2) The combination of two vertical well as injectors and one horizontal well as a producer leads to the maximum CO_2 storage at the end of the enhanced oil recovery (EOR) period in this reservoir.

(3) Three production rates (1000, 1500, and 2000 bbl/day) were investigated. The results indicate that the production rate has minimal effect on the CO_2 storage capacity of the reservoir.

(4) Increasing the H_2S content in the injected CO_2 stream reduces the MMP and increases the final gas storage capacity of the reservoir.

(5) Early implementation of CO_2 injection in this reservoir leads to a higher amount of CO_2 stored in the reservoir.

(6) Vertical upward CO_2 injection has no effect on increasing the amount of CO_2 stored in the Zama Keg River F Pool.

(7) CO_2 flooding projects can be conducted in the Zama Keg River F Pool with a utilization factor of 0.41 tonnes of CO_2 stored per one barrel of oil produced.

Acknowledgment

The authors thank Apache Canada, Ltd., and the Petroleum Technology Research Center (PTRC) for their financial support.

Literature Cited

(1) Asgarpour, S. An Overview of Miscible Flooding. *J. Can. Pet. Technol.* **1994**, *33*, 13.

(2) Hill, M. Alberta's Reserves 2003 and Supply/Demand Outlook 2004–2013. Alberta Energy and Utilities Board Report, Statistical Series ST98-2004, 2004.

(3) Hagoort, J. Oil Recovery by gravity drainage. Presented at the SPE 53rd Annual Fall Technical Conference and Exhibition, Houston, TX, October 1–3, 1978, SPE Paper No. 7424.

(4) Taber, J. J.; Martin, S.; Seright, R. EOR Screening Criteria Revisited—Part 1: Introduction to Screening Criteria and Enhanced Recovery Field Projects. *SPE Reservoir Eng.* **1997**, 189.

(5) Laieb, K.; Tiab, D. Design and Performance of Miscible Flood Displacement. Presented at the SPE Permian Basin Oil and Gas Conference, Midland, TX, May 15–17, 2001, SPE Paper No. 70021.

(6) Jarrell, P. M.; Fox, C. E.; Stein, M. H.; Webb, S. L. *Practical Aspects Of* CO_2 *Flooding*; SPE Monograph Series, Vol. 22; Society of Petroleum Engineers: Richardson, TX, 2002.

(7) Taber, J. J.; Seright, R. S. Horizontal Injection and Production Wells for EOR or Waterflooding. Presented at the 1992 SPE Permian Basin Oil and Gas Recovery Conference, Midland, TX, March 18–20, 1992, SPE Paper No. 23952.

(8) Lim, M. T.; Khan, S. A.; Sepehrnoori, K.; Pope, G. A. Simulation of Carbon Dioxide Flooding Using Horizontal Wells. Presented at the 67th Annual Technical Conference in Washington, DC, October 4–7, 1992, SPE Paper No. 24929.

(9) Malik, Q.; Islam, M. CO_2 Injection in the Weyburn Field of Canada: Optimization of Enhanced Oil Recovery and Greenhouse Gas Storage with Horizontal Wells. Presented at the SPE/DOE Improved Oil Recovery Symposium, Tulsa, OK, April 3–5, 2000, SPE Paper No. 59327.

(10) Riemer, P. The Utilization of Carbon Dioxide From Fossil Fuel Fired Power Station. Presented at the IEA Greenhouse Gas R&D Programme, 1994, Paper No. IEAGHG/SR4.

Received for review May 15, 2005
Revised manuscript received October 4, 2005
Accepted October 7, 2005

IE050572Y