OPTIMIZATION OF CARBON DIOXIDE SEQUESTRATION AND IMPROVED OIL RECOVERY IN OIL RESERVOIRS

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ABSTRACT

Carbon dioxide (CO_2) storage into depleted or partially depleted oil reservoirs is an immediate option to reduce CO_2 emissions into the atmosphere. This process, if implemented in partially depleted oil reservoirs, combines both environmental benefits by reducing CO_2 concentration in the atmosphere and economical benefits by maximizing oil recovery. However, application of CO_2 storage/EOR in carbonate reservoirs is more challenging due to their extreme heterogeneity of both porosity and permeability.

Past injection/production practices, aquifer strength, reservoir heterogeneity, and CO_2 injection schemes, such as injecting CO_2 at the top or bottom of the reservoir or using horizontal wells instead of vertical wells for injection and production purposes are among the main factors affecting both oil recovery and CO_2 storage capacity. This paper discusses the effects of different injection schemes and the timing of injection on optimization of oil recovery/CO_2 storage capacity for a partially depleted oil reservoir. A simulation study was completed using a 3-D compositional simulator "CMG™" in order to optimize CO_2 injection into a carbonate oil pool located in Northern Alberta. The simulation study proceeded through the following steps: 1) calibration of the model to match the production history; 2) comparison of different injection schemes using the existing wells; 3) testing the effect of injection timing on the CO_2 storage capacity; and 4) evaluation of the effect of production rate on the process.

Based on the results from this study, it has been concluded that oil recovery/CO_2 storage can be optimized by adjusting the starting time for CO_2 injection and the injection scheme (i.e. type and location of injection and production wells).

INTRODUCTION

The vast majority of industrialized countries, irrespective of their position regarding the Kyoto Protocol, have started to take actions toward reducing the emission of carbon dioxide (CO_2) and other gases, such as methane (CH_4) and nitrous oxide (N_2O), into the atmosphere. For instance, Canada targets about 6% reduction below 1990 levels between the years 2008 and 2012. These emissions, known also as greenhouse gases (GHGs), are believed to be the major cause of global warming and linked to other problems, such as air pollution and acid rain. One mitigative measure for global warming is to capture CO_2 from flue gas streams and sequester it in underground reservoirs.

Alberta's CO_2 contribution to Canada's 1990 total emissions was 27% and ranked the second highest after Ontario. In 1995, Alberta's share had increased to 30% of the total national emissions (151 Mt CO_2) [1]. By 1999 Alberta's emissions was 205 Mt CO_2 [2]. These figures indicate that Alberta is one of the major CO_2 emission producers in Canada and it has an increasing trend. Therefore, it is clear that an assessment of the CO_2 sequestration options and their storage potential in Alberta is essential to meet any future emissions reductions targets.

Carbon dioxide storage in mature and/or partially depleted oil and gas reservoirs is an immediate option that has two major benefits; 1) the economics are improved because of the value-added component associated with incremental hydrocarbon recovery, and 2) it is environmentally beneficial since large amounts of CO_2 could be sequestered away from the atmosphere. However, selecting the right underground reservoir for storing CO_2 is not straightforward. Besides the long-term fate of CO_2 in the reservoir, one should also determine the maximum or optimum amount of CO_2 that could be stored in the reservoir. If CO_2 storage is pursued in conjunction with improving oil recovery, the issue of determining the optimum amount of CO_2 stored becomes more vital due to its

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direct effect on the economy of the project. The purpose of this paper is to elucidate the findings from a series of simulation studies conducted with the aim of optimizing CO_2 storage and EOR in a Canadian carbonate reservoir.

The field under study is a pinnacle reef in the Zama Sub-basin located in Northern Alberta. The reef has a dome shape (Figure 1) with a thickness of more than 200 ft over a small area (about 34 acres at the oil water contact). The reef is in the Keg River Formation and is disconformably overlain by the Zama Member of the Muskeg Formation. Core and log data analysis show high permeability values in some cores, which are attributed to the vuggy nature of this carbonate reservoir. The pool is connected to a weak aquifer with no evidence of communicating with other pinnacles in the same depositional basin. There are several hundred such pools in the same region. Hence, the results obtained from this study can be used for future development of similar pools in this area.

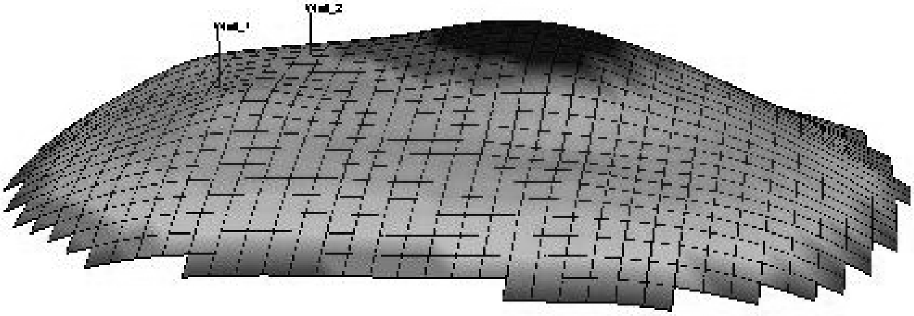

Figure 1: 3-D display of the reservoir.

Many factors influence both oil recovery and storage capacity in a hydrocarbon reservoir. Reservoir geology, fluid properties, past injection/production practices, and the CO_2 injection schemes impact the final results of a project greatly. Therefore, a detailed study of these parameters is needed to assess the relative role and extent of the effect of these variables on optimizing CO_2 storage and EOR. Reservoir simulation is a powerful tool that can be exploited to study the effect of various parameters in order to design a better developmental plan.

In this study, the goal has been to investigate the effect of a variety of processes in order to optimize both CO_2 storage capacity and improved oil recovery. The following steps were taken in order to achieve this goal:

- characterize the reservoir using core analysis, log interpreted data, PVT studies, geological data, and the production/injection history;
- build static and dynamic reservoir models and calibrate them using the production and the injection history in order to use it for future prediction scenarios and parametric studies;
- optimize the injection schemes, such as injecting CO_2 at the top or bottom of the reservoir or using horizontal wells instead of vertical wells for injection and production purposes;
- investigate the effect of production rate on ultimate oil recovery and CO_2 storage

BACKGROUND

CO_2 injection into oil reservoirs has been applied for decades. Currently seventy-five active CO_2 floods operate in five countries worldwide [3] producing more than 194 MMBOPD. The most active CO_2 flooding area is the U.S. Permian basin, which produces from shallow Carbonate reservoirs that have an average depth of 5200 ft, 107°F, 0.13 porosity, 1.4 cP viscosity and average crude gravity of 36°API [3]. Carbon dioxide, when introduced into the reservoir, develops miscibility through multiple contacts with the reservoir oil. However, a certain pressure, called the minimum miscibility pressure (MMP), is needed to achieve this miscibility. When CO_2 is above its critical point (1071 psi, 88°F), its density is in the range of the reservoir oil density, but its viscosity is less than that of reservoir oil, which will result in an unfavourable mobility ratio. Laboratory and field tests have indicated that even under very favourable conditions, injection of 5-20 Mscf of CO_2 is required to recover an additional barrel of oil [4]. In traditional EOR, the main goal is to maximize oil recovery with minimum CO_2 injection, as CO_2 is seen as an expensive commodity. Conversely, in CO_2 sequestration cases, such as the one presented here, we are trying to simultaneously increase the CO_2 storage capacity in a partially depleted oil and gas reservoir without sacrificing oil and gas recovery.

Malik and Islam [5] studied the effect of different CO_2 injection scenarios on both oil recovery and storage capacity. They concluded that maximum oil recovery could be obtained by injecting CO_2 into the formation after the waterflood for reservoirs with bottom water and injecting CO_2 in the early life of the reservoir in the presence of bottom water and high reservoir pressure. On the other hand, CO_2 storage capacity can be increased in the presence of bottom water with early injection (post-primary injection) into the producing formation and in reservoirs above its MMP (miscible scheme).

Shaw and Bachu [6] studied the effect of aquifer strength on the storage capacity in oil and gas reservoirs using a material balance approach. They found that, on average, strong aquifers could reduce the CO_2 storage capacity by 28% for gas reservoirs and by 60% for oil reservoirs. For weak aquifers, it does not have that much effect because the water will be expelled from the reservoir by the time the reservoir pressure builds back to its initial pressure. However, the effect of different parameters varies from one reservoir to another. Therefore, a reservoir-by-reservoir study is needed for optimizing CO_2 storage capacity versus oil recovery.

PRODUCTION AND INJECTION HISTORY

Initial oil production from this field was started in April 1967 through Well 1. The pressure declined very fast from its initial pressure of 2100 psi as a response to the oil production and reached the bubble point pressure in less than two years. PVT and GOR data show that the saturation pressure was 1275 psi. After the gas started to breakthrough, the GOR increased dramatically to reach more than 1000 Scf/STB compared to the initial GOR of 300 Scf/STB with no water production reported until early 1974. Water production was a problem and it was addressed through many workovers, which primarily consisted of plugbacks and re-perforation of higher layers. Detailed analysis of the water production mechanism was performed using WOR derivative diagnostic plots [7]. This analysis indicated that water channelling through high permeability streaks and fractures could be responsible for this behaviour.

In 1987, this well was converted into a disposal well, through which more than 2.4 MMSTB of water has been pumped into the formation. In 2002, Well 2 was drilled and the measured reservoir pressure was 3425 psi. This well was put on production in the same year, and it started producing about 300 STB/day. The production rate declined very fast, while at the same time, the water cut and GOR increased dramatically. By May 2003, the overall production from this reservoir was 1.103 MMSTB of oil, 540 MMscf of gas, and 0.4 MM bbl of water, and the recovery factor has been estimated to be 31%.

RESERVOIR CHARACTERIZATION AND THE GEOLOGICAL MODEL

The reservoir under study is a heterogeneous carbonate reef composed of two distinct dolomite formations separated by anhydrite barriers. The upper formation's thickness is 80 ft, and it has 0.08 porosity and high permeability, in the range of 100 md, except the first 18 ft zone, which has 1000 md permeability. The lower formation is more heterogeneous, with an average thickness of 85 ft, average porosity of 0.09, and average permeability of 300 md. The average reservoir depth is 3700 ft with an initial pressure and temperature of 2100 psi and 160 °F, respectively. The oil has a viscosity of 2.64 cP and an average crude gravity of 34 °API. For this study, the data used to generate the geological model included: 3-D seismic, well- interpreted logs and core data from Well_1, and formation tops from Well_2. The main challenge encountered was building the geological model using only one well for modelling such a heterogeneous reservoir. Even though the vertical heterogeneity was captured (assumingly), the lateral variations were not. The attic of the pinnacle was not penetrated by either Well_1 or Well_2. Hence, the properties of adjacent known layers' were assigned to the attic of the pinnacle reef under study. Composite porosity data from core and log data was assigned to the model grid blocks. A porosity-permeability cloud transform was used to assign the horizontal permeability to each grid block in the model. The model contains a total of 49,950 grid blocks (30 X 37 X 45) of which 15,763 were active grid blocks. The average size of the grid blocks is 50 x 50 x 6 ft in I, J, and K directions, respectively. The final model was exported to the numerical simulator "CMG-GEM™," which was used later for a variety of simulation studies (see Figure 1).

AQUIFER REPRESENTATION

Early analysis of the aquifer influence using material balance calculations showed that the aquifer was weak, as demonstrated by a Campbell diagnostic plot [8] and the pressure depletion-declining trend. However, its exact extension and strength are not known because there is no pres[illegible] data recorded from other parts of the reservoir.

During the process of building the geological model, additional layers below the oil-water contact were added to allow enough grid cells to enhance aquifer model influence. A trial-and-error approach was used in the early history-matching phase to identify the proper aquifer model and to estimate its physical limits and its characteristics.

PVT MODEL FOR THE COMPOSITIONAL SIMULATOR

An 8-component Peng-Robertson EOS system was successfully developed and tuned based on the routine PVT tests (Differential Liberation and Separator tests) using WINPROP™ module. The procedure was a mix of splitting and lumping of the original 12 components. The heavy component (C_7+) was split into three pseudo components; these components are C_7-C_{13}, C_{14}-C_{17} and C_{18}+. The other components were lumped as follows: N_2 and C_1, C_2 to n-C_4 and iso-C_5 to FC_6. This model was exported to the fully compositional simulator (CMG-GEM™), which uses EOS to calculate phase equilibrium and the mass transfer of components between phases.

MINIMUM MISCIBILITY PRESSURE STUDY

Recent PVT study using new oil samples collected from Well_2 has indicated that the data for the Well_2 reservoir fluid compare very well with previous measurements. The oil gravity and saturation pressure were 34 API and 1276 psig, respectively, compared to 33.9 API and 1275 psig measured previously in 1967. The minimum miscibility pressure measurement was carried out using the rising bubble apparatus. Two injection gases were used, pure CO_2 and 20% H_2S in CO_2 stream. The minimum miscibility pressure for pure CO_2 was 2886 psi compared to 2407 psi for the 20% H_2S in CO_2 stream.

HISTORY MATCH

A single porosity, single permeability model was used for history matching process. Oil rate, GOR, reservoir pressure, and water cut have been matched simultaneously using the oil rate as the controlling parameter. Figure 2 shows the final results of the history-matching phase for the observed and simulated data. Relative permeability data was obtained from an analogous reservoir, and capillary pressure data was obtained from the saturation profile calculated from well-interpreted log data. A trial-and-error process was used to identify less certain or missing data.

The results of history matching indicate that original oil in place (OOIP) is about 3.56 MMSTB, and the formation is oil wet with a residual oil saturation of 30%. The current reservoir pressure is 700 psi, which means the reservoir needs to be pressured up to more than the MMP of 2500 psi to ensure miscible displacement.

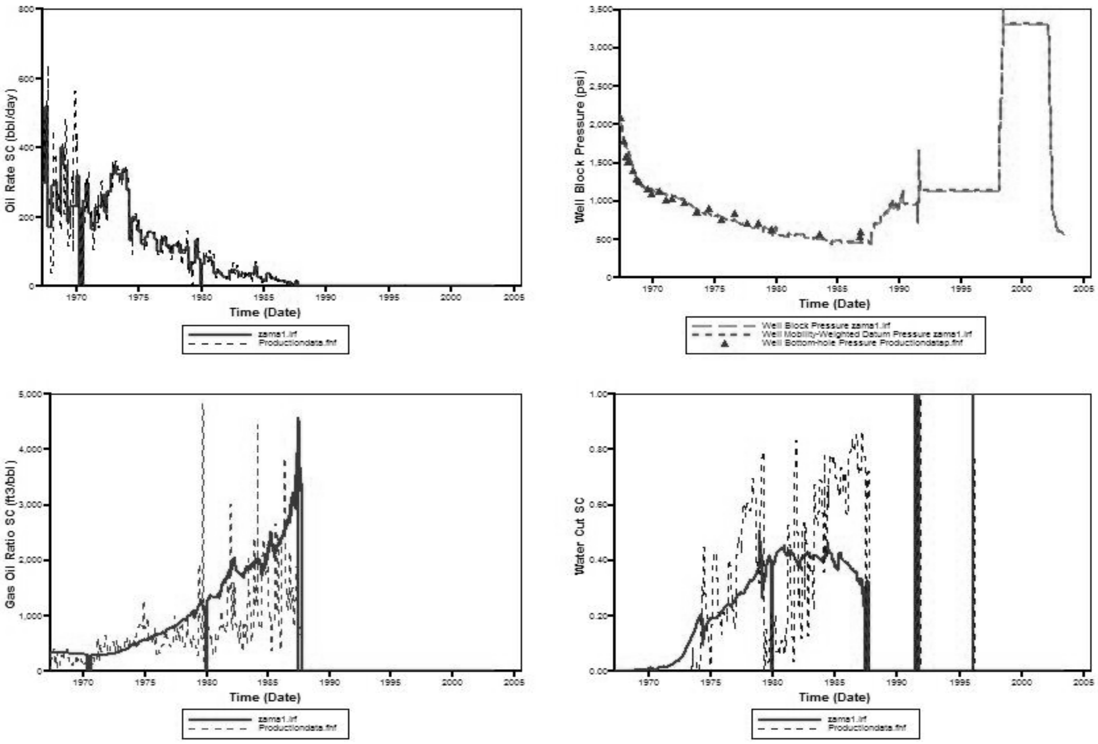

Figure 2: History match.

OPTIMIZATION OF OIL RECOVERY / CO_2 STORAGE CAPACITY

After the history match phase was completed, several prediction scenarios were performed to investigate the applicability of CO_2 injection in the reservoir. Raising reservoir pressure higher than the MMP is essential to ensure miscible displacement. Except for one prediction case, the operating pressure was kept higher than the MMP of 2500 psi, and the maximum liquid production rate was 1000 bbl/day. For the injection well, two constraints were imposed: 1) the injection rate was kept at 3.4 MM scf/day of 10% H_2S in CO_2 stream; and 2) the injection pressure was not allowed to exceed the reservoir parting pressure of 4300 psi. The main goal of all these predictions is to find the injection/production scheme that optimizes both amount of CO_2 stored and incremental oil recovered. All these runs have been restricted to 20 years of operation. A description of each case follows:

1. ***Case 1 (Base Case):*** In this case, a vertical downward CO_2 injection from Well_2 (top of the formation) and production from Well_1 (bottom of the formation) was established to maximize the gravity segregation effect and minimize viscous fingering and channelling. Maximum oil recovered at the end of twenty years of injection was 1.637 MMSTB (incremental EOR 16% of OOIP), and the total CO_2 stored was 0.357 Mt (Figure 3).
2. ***Case 2:*** In this case, a higher production rate (1500 bbl/day of liquid) was implemented while keeping other parameters unchanged from Case 1. Sweep efficiency was almost the same, mainly due to the close proximity of injection and production wells. Maximum oil recovered at the end of twenty years of injection was 1.634 MMSTB with an incremental EOR of 15.8% OOIP, and the total CO_2 stored was 0.358 Mt (Figure 4). It was observed that higher production rates accelerated the gas breakthrough and reduced the ultimate oil recovery.

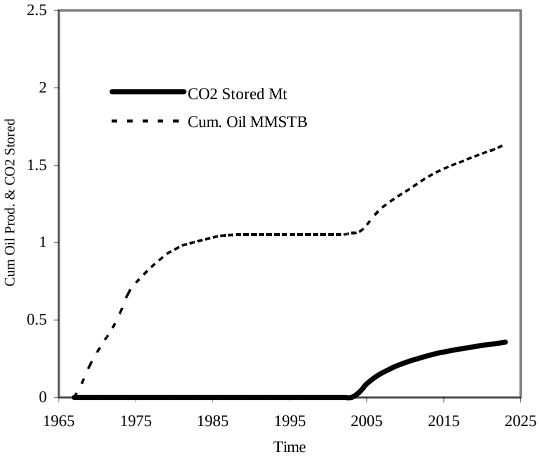

Figure 3: Case 1 (Base case).

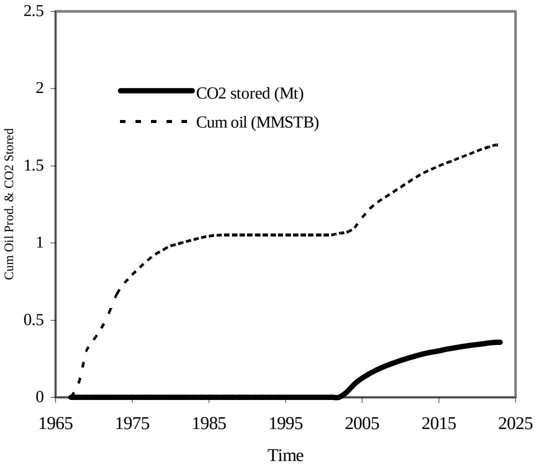

Figure 4: Case 2.

3. ***Case 3:*** Here, CO_2 injection was conducted from the bottom of the formation while oil was producing from the top of the formation. Figure 5 shows that the ultimate recovery was 1.93 MMSTB with an incremental EOR of 24% OOIP. The total CO_2 stored was 0.358 Mt. In this scheme, the oil recovery was improved but the storage capacity was not.
4. ***Case 4:*** The effect of replacing the existing vertical wells with horizontal wells on ultimate oil recovery and CO_2 storage was studied in this case. For this scenario, CO_2 injection took place in the top of the formation through a horizontal well and the production was from another horizontal well at the bottom layers. Oil recovered was 1.88 MMSTB (EOR recovery of 22.7% OOIP), and the total storage capacity was improved to 0.432 compared to 0.357 Mt in the base case, as shown in Figure 6.
5. ***Case 5:*** In this case, CO_2 was injected in a horizontal well at the bottom of the reservoir while oil was produced from another horizontal well at the top of the formation. The results indicated that oil recovery improved dramatically, to 2.12 MMSTB with an EOR recovery of 29% OOIP, but the CO_2 storage capacity dropped to 0.36, as shown in Figure 7. Once again, injecting CO_2 from the bottom increased the oil recovered while having a very negative effect on the total amount of CO_2 stored.
6. ***Case 6:*** The process of line-drive displacement between two vertical wells was investigated in this scenario, where both vertical wells were extended to the bottom of formation. One well was used as injector and the other well was used for production purposes. However, the oil recovery was low compared the Base Case (1.48 versus 1.637 MMSTB) as shown in Figure 8. The gas stored was 0.304 Mt, which is lower than other cases studied. The reason behind the low oil recovery and the low CO_2 storage is the close proximity between the injector and the producer and the high permeability layers which acted as a conduit for the injected gas and adversely affected the sweep efficiency.

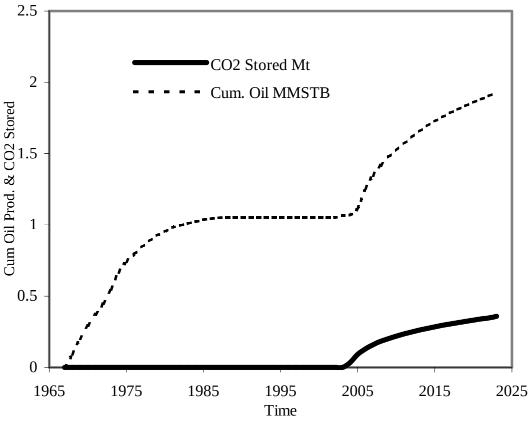

Figure 5: Case 3.

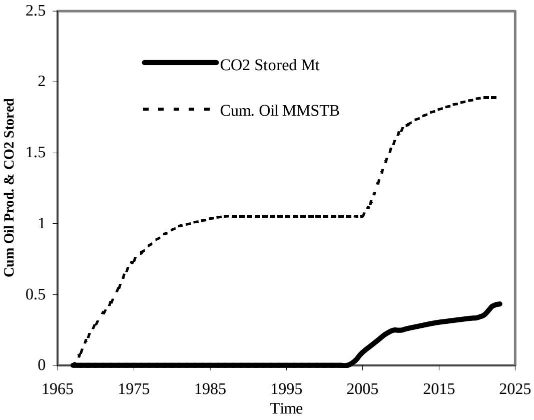

Figure 6: Case 4.

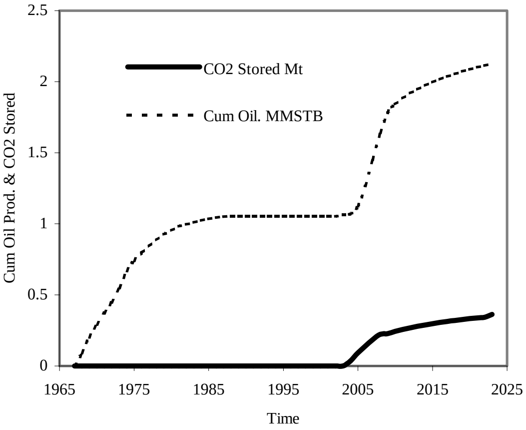

Figure 7: Case 5.

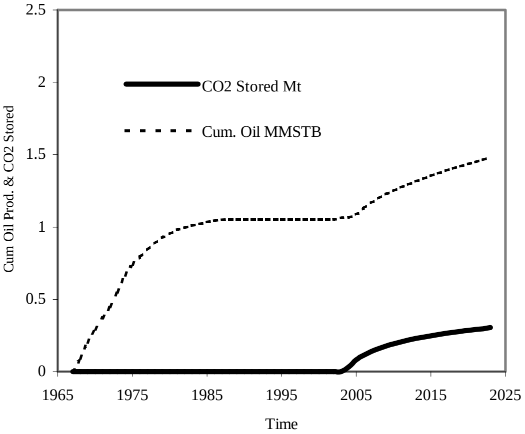

Figure 8: Case 6.

7. ***Case 7:*** In order to study the effect of past production schemes on ultimate oil recovery and amount of CO_2 stored, this case investigated the scenario wherein CO_2 injection was started at the end of primary production and before water injection in this field. In this plan, the injection of CO_2 started when the reservoir reached its bubble point pressure in 1969. The injection and production wells, as well as their rates and constraints, were the same as the Base Case. The results obtained, as presented in Figure 9, indicate that the oil recovered was 1.77 MMSTB, mostly due to the CO_2 flooding process. Also, the storage capacity for CO_2 is 0.395 Mt, which is higher than the Base Case. In this case, it is clear that CO_2 injection could have been implemented early in the life of the reservoir when its pressure fell below the saturation pressure.
8. ***Case 8:*** This case was identical to the Base Case except that production was commenced as soon as CO_2 injection started. Since the reservoir pressure was less than MMP, oil production occurred by immiscible displacement during its initial stages. Total oil recovered for this case was 1.63 MMSTB with an EOR of 15% OOIP, and the total CO_2 stored was 0.358 Mt (Figure 10). The ultimate oil recovered and CO_2 stored were almost the same as the Base Case.

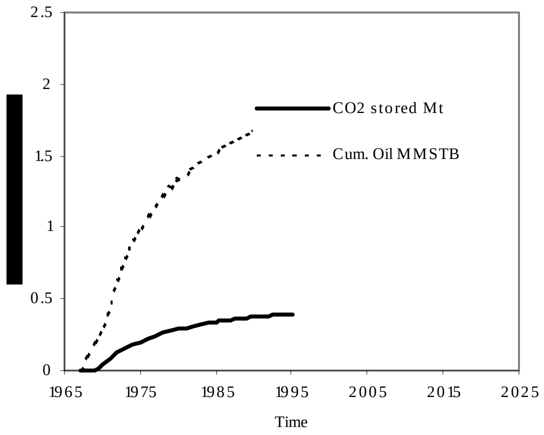

Figure 9: Case 7.

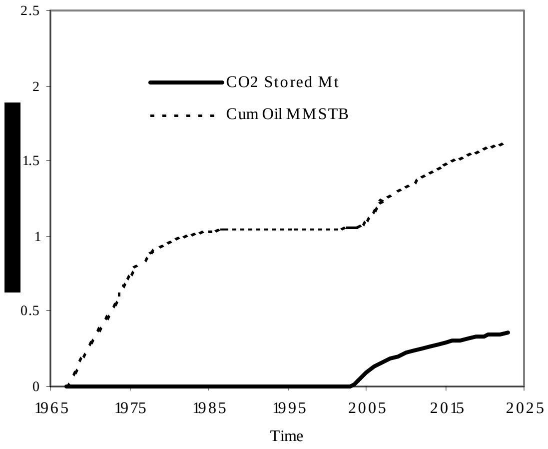

Figure 10: Case 8.

A comparison of the ultimate oil recovery versus CO_2 storage for the above eight cases, at the end of the simulation period, is presented in Figure 11.

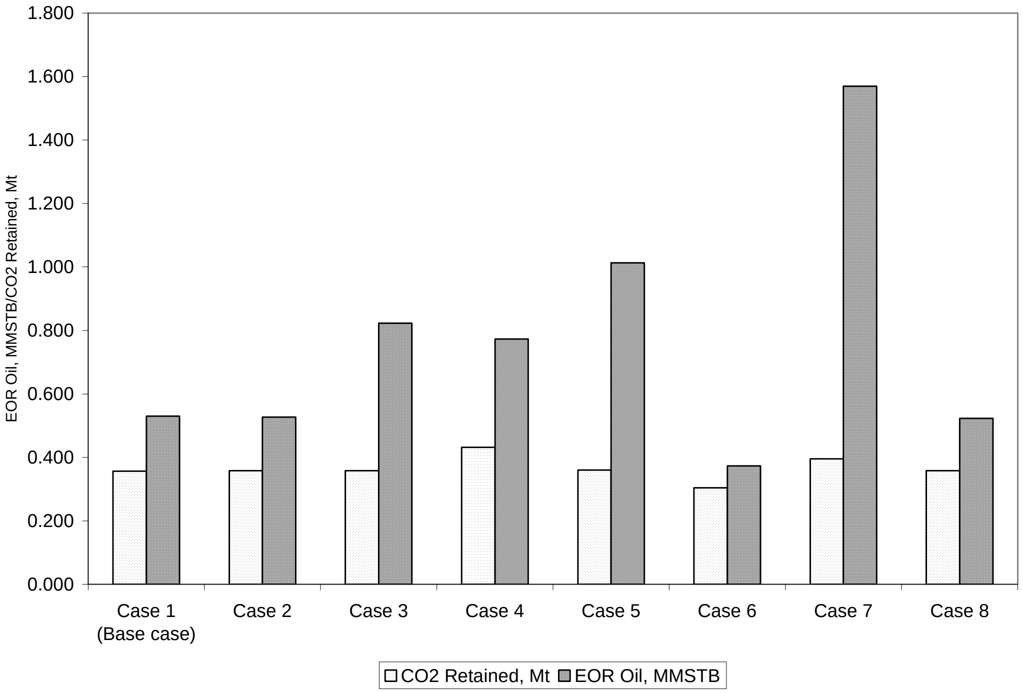

Figure 11: Comparison of the ultimate oil recovery and CO_2 storage capacity for the eight cases presented.

CONCLUSIONS

Based on the results of different prediction scenarios, the following conclusions can be drawn:

1. Reservoir-by-Reservoir studies are needed to assess reservoir storage capacity, and reservoir simulation is a powerful tool for conducting these studies;
2. Horizontal wells can be used to improve both the ultimate oil recovery and the storage capacity;
3. Early, post-primary, CO_2 injection leads to the highest amount of oil recovered.

4. For the reservoir under study, injecting CO_2 from the bottom of the formation and producing from the top improved the incremental oil recovered.
5. The results obtained for the pinnacle reef under study is useful in future implementation of CO_2 flooding in other reefs in the same basin. The total CO_2 storage capacity can also be estimated for the entire basin, assuming the other reefs are of comparable size.

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