An Integrated Framework for Optimizing CO 2 Sequestration and Enhanced Oil Recovery

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An Integrated Framework for Optimizing CO_2 Sequestration and Enhanced Oil Recovery

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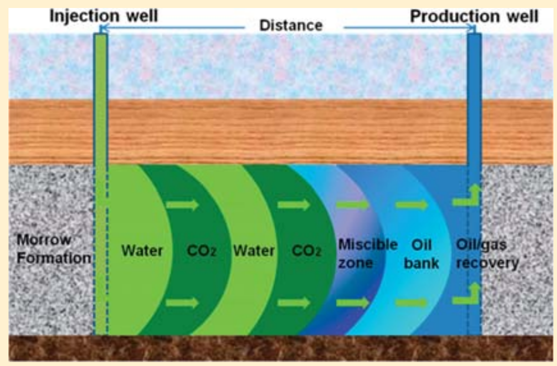
S *Supporting Information*

ABSTRACT: CO_2-enhanced oil recovery (CO_2-EOR) is a technique for commercially producing oil from depleted reservoirs by injecting CO_2 along with water. Because a large portion of the injected CO_2 remains in place, CO_2-EOR is an option for permanently sequestering CO_2. This study develops a generic integrated framework for optimizing CO_2 sequestration and enhanced oil recovery based on known parameter distributions for a depleted oil reservoir in Texas. The framework consists of a multiphase reservoir simulator coupled with geologic and statistical models. An integrated simulation of CO_2−water−oil flow and reactive transport is conducted, followed by a global sensitivity and response surface analysis, for optimizing the CO_2-EOR process. The results indicate that the reservoir permeability, porosity, thickness, and depth are the major intrinsic reservoir parameters that control net CO_2 injection/storage and oil/gas recovery rates. The distance between injection and production wells and the sequence of alternating CO_2 and water injection are the significant operational parameters for designing a five-spot CO_2-EOR pattern that efficiently produces oil while storing CO_2. The results from this study provide useful insights for understanding the potential and uncertainty of commercial-scale CO_2 sequestrations with a utilization component.



1. INTRODUCTION

Carbon dioxide (CO_2) has been sequestered in oil reservoirs via enhanced oil recovery (EOR) technologies for more than 40 years.[1,2] There is renewed interest in sequestering CO_2 in EOR sites because the U.S. Department of Energy's CCS (Carbon Capture and Storage) program has been modified to include a utilization component (or CCUS, Carbon Capture Utilization and Storage). Currently, CO_2-EOR provides ∼5% percent of the total U.S. crude oil production.[3] Because of CCS technology advances in the past decade, prolonged high oil prices, and the potential availability of large anthropogenic CO_2 sources, CO_2-EOR is likely to expand in the next few decades. CO_2-EOR uses water-alternating-with-gas (WAG) cycles to control CO_2 mobility and CO_2 flood conformance and to tackle the clogging and scale issues in the depleted reservoir.[3] Currently, there are a few operational and technical issues for CO_2-EOR at commercial scales: (1) uncertainty in characterizing CO_2−water−oil systems in depleted reservoirs, (2) a lack of robust guidelines for determining injection and production well distances, (3) operational difficulty in determining the time ratio for water alternating CO_2 gas injection, and (4) difficulty in controlling the CO_2 flood conformance and monitoring the flood performance.[3−19] If the first three issues can be quantitatively evaluated and solved, the results will indirectly help solve the fourth issue of CO_2 flood conformance and performance evaluation.

This study couples a multiphase reservoir simulator with geologic and statistical models to improve our understanding and optimize the performance of CO_2-EOR. In addition, we examine the significant impact of reservoir heterogeneity by extending the work of Deng et al.[20,21] Specifically, we extend the heterogeneity characterization method[20] for conducting a global sensitivity and response surface analysis that is applied to an actual depleted oil reservoir (the Farnsworth Unit CO_2-EOR project in Texas) to predict and optimize the distance between injection and production wells and the time ratio for alternating CO_2 and water injection.

The Farnsworth Unit (operated by Chaparral Energy LLC) is located in the Anadarko Basin, Ochiltree County, in northern Texas. The Southwest Partnership (SWP) and Chaparral selected the Morrow formation as its primary test reservoir to evaluate long-term storage of CO_2 and performance of EOR.[18] The source of CO_2 used by the test is a fertilizer plant in

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Borger, TX, and an ethanol plant in Liberal, KS. Net CO_2 injection is planned at a rate of ~210000 tons/year or ~1.05 million tons (Mt) over the 5 year project. The Morrow formation predominantly consists of incised valley-fill sandstones of the Lower Pennsylvanian that extend from Texas to Colorado.[22−24] The Morrow reservoir has produced more than 100 million barrels of oil and 14.16 billion m^3 of gas.[22]

2. MATERIALS AND METHODS

The incised valley-fill sandstone Morrow formation at the Farnsworth site is at a depth of ~2.5 km and a typical thickness between 5 and 50 m. The permeability values in the Morrow formation range between 1 and 500 mD with porosities between 0.05 and 0.25 at the Farnsworth site. Previous studies of oil fields within the Anadarko Basin provide information about the ranges and distributions of reservoir parameters that can be expected at the Farnsowrth site, such as formation depth, thickness, permeability, and porosity.[22−26] Figure S1 of the Supporting Information illustrates the measured permeability and porosity data in the Morrow formation collected from Texas to Colorado.[22] The data points within the green circle represent the permeability and porosity distributions at the Farnsworth site. On the basis of these parameter ranges and additional geological data,[22−26] we estimate the ranges and distributions of the uncertain parameters (Table 1) for simulating reservoir heterogeneity. All parameters listed in the table are assumed to be uniformly distributed for sampling the input parameters to build response surfaces. On the basis of the statistical distribution of these parameters, we develop integrated Monte Carlo methods to simulate CO_2−water−oil flow and transport in the reservoir by coupling the uncertainty quantification tool PSUADE,[27] the geostatistical modeling tool GEOST[28,29] (modified from GSLIB[30]), and the multiphase reservoir simulator SENSOR.[31]

Table 1. Uncertain Parameters and Objective Functions for the Farnsworth Site

	minimum	maximum	mean
Reservoir (Morrow) Parameters			
thickness (m)	5.0	50	27.5
depth (km)	1.5	3.5	2.5
permeability (D)	0.001	0.5	0.25
integral scale (km)	0.1	0.5	0.3
porosity	0.05	0.25	0.15
injection pressure (MPa)	12	45	25
injection distance (km)	0.1	0.5	–
time ratio of WAG	0.0	10	–
Objective Functions			
net CO_2 injection (Mt)			
cumulative oil production (MMbbl)			

PSUADE is used to sample the uncertain parameters based on a statistical analysis of the field data at or near this site, to conduct global sensitivity analysis for understanding the relationships of the input parameters and the objective functions, and to derive response surfaces [or reduced order models (ROMs)] for optimally determining the key operational parameters for CO_2-EOR. GEOST is used to analyze the reservoir heterogeneous parameters and to generate heterogeneous fields for reservoir simulations. The reservoir simulator SENSOR is used to model CO_2−water−oil flow and transport in the reservoir for each generated heterogeneous model within the integrated Monte Carlo simulation framework.

For quantitatively evaluating the major operational and technical parameters in this site, we defined a set of objective functions to postprocess the Monte Carlo simulation results and derive response surfaces. These objectives maximize (1) the net CO_2 injection amount (i.e., the difference between gross CO_2 injected and produced CO_2, which is directly equivalent to CO_2 stored) and (2) cumulative oil production after five years, or

$$\text{objective 1} = \max_{p \in R} \sum_{i=1}^{N_t} \{C_i^{\text{inj}}(p) - C_i^{\text{prd}}(p)\}\Delta t_i$$

$$\text{objective 2} = \max_{p \in R} \sum_{i=1}^{N_t} q_i(p)\Delta t_i$$

where p is the operational parameter, R is the parameter space, N_t is the number of the time periods, C_i^{inj} and C_i^{prd} are CO_2 injection and production rates, respectively, at time period i, Δt_i is the length (days) of time period i, and q_i is oil production rate at time period i. By developing response surfaces for the chosen objectives, we conduct a statistical analysis to estimate the optimal CO_2 injection distance and the time ratio for alternating water and CO_2 injection in the Farnsworth field.

3. RESULTS AND DISCUSSION

On the basis of the data listed in Table 1, we coupled PSUADE and GEOST to generate 2000 realizations through Latin Hypercube sampling and geostatistical modeling to perform an integrated Monte Carlo simulation of CO_2−water−oil flow and transport in the Morrow reservoir. The heterogeneous permeability fields are simulated with a sequential Gauss method. Because of limited existing data, we assume that the horizontal integral scales are 100 times larger than those of the vertical integral scales and anisotropic factors (the permeability ratio in vertical and horizontal directions) are assumed to be 0.1. A single realization of the reservoir permeability fields within a five-spot EOR pattern is shown in Figure 1.

CO_2 Injection and Oil/Gas Production Simulations. In a conventional five-spot pattern (Figure 1), the production well is located in the center surrounded by four injection wells at the corners of the pattern. The heterogeneity in the model area is assumed to be symmetric in all four quadrants of the EOR pattern. This way, only one-quarter of the five-spot pattern is required in the model with one injection well and one-fourth of the production well. The reservoir simulator SENSOR was used to simulate CO_2 injection and oil/gas production at the Farnsworth site over 5 years for the 2000 realizations. The WAG injection scheme is designed to identify the best time ratio (R_{WAG}) for alternatively injecting CO_2 gas and water within each time period or cycle (such as 10 or 30 days). This injection ratio is calculated as

$$R_{\text{WAG}} = \frac{CO_2 \text{ injection time (days)}}{\text{water injection time (days)}}$$

When the sampled ratio changes, the WAG scheme is changed correspondingly. The numerical model sizes and grid numbers are varied with the sampled injection distances and reservoir thicknesses. The relative permeability functions for CO_2−water−oil multiphase flow simulations were calculated on the basis of Stone's approach to define the related

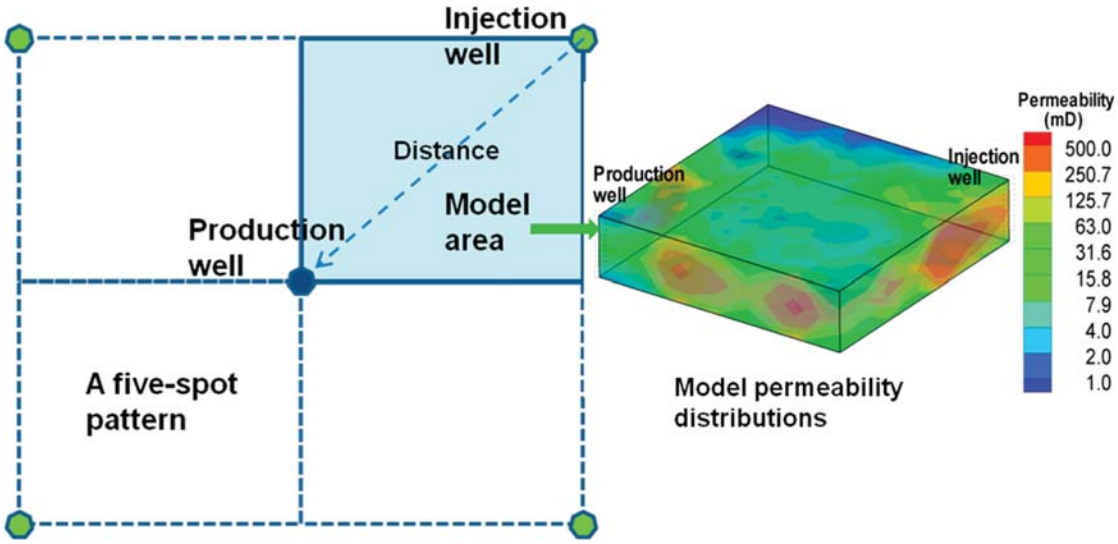

Figure 1. Simplified illustration of a five-spot CO_2-EOR pattern and model permeability distributions.

coefficients.[31−34] The resulted relative permeability curves are shown in Figure S2 of the Supporting Information. Figure S2 represents two relative permeability−saturation tables: (a) a water−oil table for defining water and oil relative permeabilities relevant to water saturation and (b) a gas−oil table for defining gas and oil relative permeabilities relevant to total liquid saturation.[31,32] For each realization, postprocessing is conducted to compute the two objective functions or output variables: net CO_2 injection amount and cumulative oil production over 5 years.

Global Sensitivity Analysis. To determine the key flow and operational parameters driving CO_2−water−oil transport behavior in the reservoir, global sensitivity analysis techniques were used for investigating objective function sensitivities over the ranges of the sampled parameters. The Monte Carlo simulations provide 2000 realizations of input parameter sets generated with Latin Hypercube sampling and geostatistical modeling. Each realization was propagated through the reservoir simulator to yield the two output objective functions. Global sensitivity analysis entails the comparison of the output distributions to each of the input parameter distributions and identifies the most important parameters for each objective function. The multivariate adaptive regression spline (MARS) method[27,35,36] was used to quantify the impact of uncertainty and sensitivity of the input parameters. The importance of the input parameters is quantified by the MARS importance ranking (from 0 to 100).[27]

By using the Monte Carlo simulation results as the input for PSUADE,[27] we conduct a global sensitivity analysis with the MARS method for the two objective functions. The results plotted in Figure 2 show that net CO_2 injection is most sensitive to the reservoir permeability, the time ratio of the WAG, and the distance between injection and production wells. The reservoir porosity and depth also have a substantial impact on net CO_2 injection. The 5 year cumulative oil production is mainly controlled by the reservoir permeability and the injection distance, as well as the reservoir depth, the thickness, and the time ratio of the WAG cycle. The permeability, porosity, depth, and thickness are reservoir intrinsic parameters, while the injection distance and WAG ratio are operational parameters. These operational parameters should be optimized

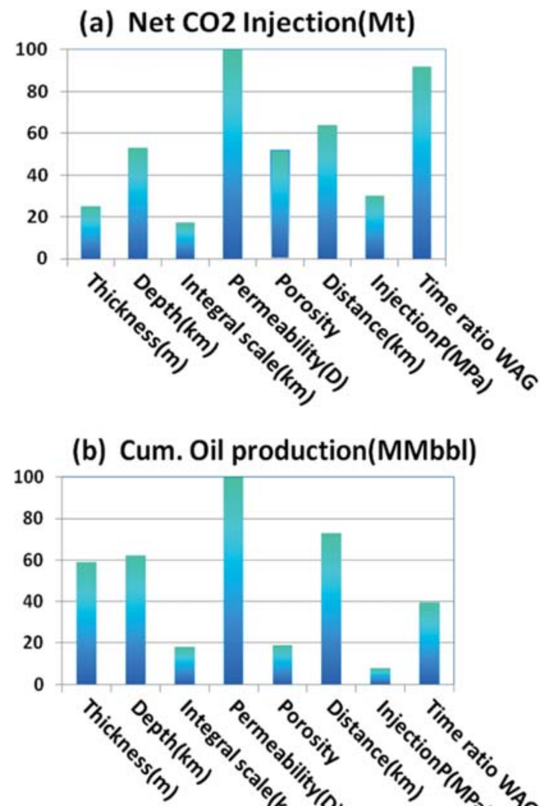

Figure 2. Global sensitivity analysis of the objective functions to eight uncertain parameters using the MARS method.

differently than they are for traditional EOR systems to improve the efficiency of CO_2-EOR systems.

Response Surface Analysis. Response surface analysis is an application of statistical and mathematical techniques useful for developing and optimizing process models and parameters.[26] Using the postprocessing results of the 2000 Monte Carlo simulations, we conducted a response surface analysis of the two objective functions by using the MARS approach with bootstrap aggregating (bagging).[27,35,36] Panels a and b of Figure

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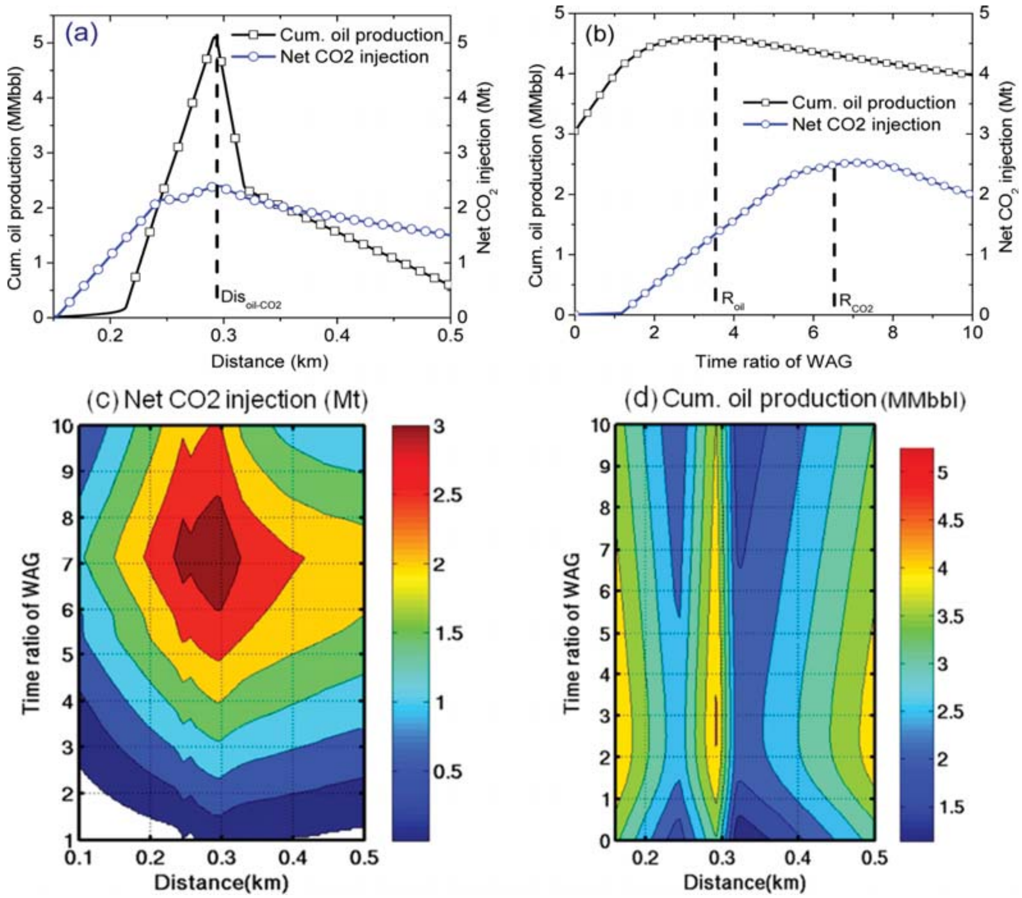

Figure 3. Determining the operational parameters with response surface analysis. Dis_{oil-CO_2} represents the optimal distance between the injection and production wells; R_{oil} and R_{CO2} are the estimated time ratios of WAG based on maximizing cumulative oil production and net CO_2 injection, respectively.

3 show the one-dimensional approach results in relation to the injection distance and the WAG ratio separately. Note that when the developed response surfaces were used to plot the two objective functions versus the operational parameters, we assigned the mean values for the reservoir intrinsic parameters (listed in Table 1). For maximizing both oil production and CO_2 injection, injection wells should be located ∼295 m from the production well (Figure 3a). If the injection distance is shorter than that, more injected CO_2 would be produced from the production well, the cumulative oil production would be reduced, and the net amount of CO_2 storage would decrease. On the other hand, if the distance is larger than 295 m, the enhanced oil recovery rate would decrease. The optimal values of the WAG ratio are different for the two objective functions: 3.5 and 6.5, respectively (Figure 3b). When the WAG ratio is larger than 3.5, the cumulative oil production rate starts to decrease slightly while the rate of net CO_2 injection keeps increasing until it is 6.5. A best value of the WAG ratio should be between 5 and 6.5 to compromise between both objective functions. The two-dimensional results shown in panels c and d of Figure 3 confirm the optimal injection distance (295 m) obtained from the one-dimensional approach and refine the range of the time ratio of WAG. The results indicate that a time ratio between 5 and 6 will be reasonable, which represents a CO_2 injection time of approximately 83−85% during a complete WAG cycle.

Implications. CO_2-EOR is promising technology for CO_2 sequestration because it provides a positive price for storing CO_2 away from the atmosphere in the absence of local or national emissions policies, and the demand for CO_2 will only increase as more domestic oil is produced using CO_2-EOR. As a result, this study develops an important approach for estimating the potential of storing CO_2 in depleted oil fields while simultaneously maximizing oil production. The optimal distance between the injection and production wells is ∼295 m for maximizing both oil production and CO_2 injection, and the best value for the WAG ratio is ∼85% for CO_2 injection and ∼15% for water injection. Further, this study has revealed key insights into the potential behavior and operational parameters of CO_2 sequestration at a CO_2-EOR site, including the impact of reservoir characterization uncertainty; understanding this uncertainty will be critical in terms of economic decision making and the cost-effectiveness of CO_2 storage through EOR. The one-dimensional and two-dimensional response surfaces are developed on the basis of the parameter ranges and distributions listed in Table 1. As the SWP project proceeds, new data about site-specific reservoir parameters (including heterogeneity) and operational parameters will be generated. These data can then be used to determine more tightly bound uncertainty estimates with an increased confidence in key framework outputs.

ASSOCIATED CONTENT

Supporting Information

Permeability and porosity data for the Morrow formation (Figure S1), relative permeability plots for water, oil, and gas (Figure S2), and unpublished work cited as ref 7. This material is available free of charge via the Internet at http://pubs.acs.org.

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Notes

The authors declare no competing financial interest.

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