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CO₂ Enhanced Oil Recovery and Storage Using a Gravity-Enhanced Process

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Nomenclature

AIC	=	Akaike information criterion
BB	=	Box-Behnken
BIP	=	binary interaction coefficient
D_z	=	depth in vertical direction, L
EOR	=	enhanced oil recovery
EOS	=	equation of state
FCM	=	first contact miscibility
H	=	reservoir depth, L , or highest value of scaling group, dimensionless
L	=	length, L , or smallest value of scaling group, dimensionless
LHS	=	Latin hypercube sampling
MCM	=	multicontact miscibility
M_g^o	=	mobility ratio (CO_2 -oil), dimensionless
MMP	=	minimum miscibility pressure, $ML^{-1}T^{-2}$
MPVI	=	moveable pore volume injected
M_w^o	=	mobility ratio (water-oil), dimensionless
N_o^w	=	buoyancy number, dimensionless
NR_g^o	=	buoyancy ratio, dimensionless
OOIP	=	original oil-in-place
PDF	=	probability distribution function
P	=	reservoir pressure, $ML^{-1}T^{-2}$
P_c	=	critical pressure, $ML^{-1}T^{-2}$
P_{inj}	=	injecting pressure, $ML^{-1}T^{-2}$
P_p	=	producing pressure, $ML^{-1}T^{-2}$
P10	=	10 th percentile
P50	=	50 th percentile
P90	=	90 th percentile
R_{bt}	=	breakthrough time for recovery, MPVI
R_{D1}	=	recovery at 0.25 MPVI, dimensionless
R_{D2}	=	recovery at 0.75 MPVI, dimensionless
R_{D3}	=	recovery at 1.2 MPVI, dimensionless
R_{D4}	=	recovery at 2 MPVI, dimensionless
R_L	=	effective aspect ratio, dimensionless
ROM	=	reduced-order model
RSM	=	response surface model
S_{bt}	=	breakthrough time for storage, MPVI
S_{D1}	=	CO_2 storage efficiency at 0.25 MPVI, dimensionless
S_{D2}	=	CO_2 storage efficiency at 0.75 MPVI, dimensionless
S_{D3}	=	CO_2 storage efficiency at 1.2 MPVI, dimensionless
S_{D4}	=	CO_2 storage efficiency at 2 MPVI, dimensionless
S_{hr}	=	residual hydrocarbon saturation
S_{oiD}	=	normalized initial oil saturation
S_{wi}	=	initial water saturation
S_{wirr}	=	irreducible water saturation
S_{wr}	=	residual water saturation
T	=	reservoir temperature, Θ
T_c	=	critical temperature, Θ
V_{DP}	=	Dykstra-Parsons coefficient
c	=	regression coefficient
d_g	=	grain diameter, L
g	=	gravitational constant, FL^2M^{-2}
k	=	permeability, L^2

k_{rw}^o = end-point relative permeability of gas-water
 k_{ro}^o = end-point relative permeability of oil-gas

Greek Symbols

λ correlation length
 ρ density, ML^{-3}
 μ viscosity, $\text{ML}^{-1}\text{T}^{-1}$
 ϕ Porosity
 ω acentric factor

Subscripts

D dimensionless
bt breakthrough time
c Corrected
g gas phase
h hydrocarbon phase
o oil phase
r Residual
w water phase
x x-direction
z z-direction

Superscripts

o oil phase
 w water phase

Abstract

CO₂ flooding offers a means to recover significant amounts of oil while simultaneously sequestering CO₂. Recent methods for CO₂ geological storage have focused on CO₂ injection into deep brine aquifers, or by water-alternating-gas (WAG) injection in a miscible gas flooding process using vertical wells. There is significant uncertainty in the amount of CO₂ that can be stored using these methods owing to reservoir heterogeneity and variations in reservoir/fluid parameters. It would be useful therefore to have a more robust process that can also increase both CO₂ storage and oil recovery in a symbiotic relationship, where increased storage leads to greater oil recovery.

This paper considers an alternative process that maximizes both storage and oil recovery simultaneously using only horizontal wells in a gravity-enhanced miscible process. A reduced-order model (ROM) is developed to consider a wide range of reservoir heterogeneities and fluid properties. Monte-Carlo simulations using the ROM show that achieving very high storage and oil recovery is possible using the gravity-enhanced process and that the approach is very robust. For example, after 2.0 moveable pore volumes injected (MPVI), probabilistic forecasts show that CO₂ storage efficiency across two standard deviations ranges from about 81 to 93%, indicating that nearly all of the available pore space (excluding immobile water) at the end of injection is occupied by CO₂. Oil recoveries after 2.0 MPVI varied from 79% to 93% of the original mass of oil-in-place (OOIP). These storage and recovery efficiencies are significantly greater than any process reported to date. Response functions developed can also be used to estimate the maximum amount of stored CO₂ and corresponding oil recoveries for a wide range of reservoir and fluid properties. Such estimates are critical for regional and national assessment of CO₂ storage potential.

1. Introduction

Fossil fuels will remain an important energy source - both in the U.S. and worldwide - for the foreseeable future (U.S. EIA, 2013). Coal combustion for power generation, however, is currently responsible for roughly one third of anthropogenic CO₂ emissions in the U.S. - representing a major contribution to domestic greenhouse gas emissions. Technology to capture CO₂ from anthropogenic point sources and store it in geologic formations is being pursued to enable continued and sustainable utilization of abundant fossil energy resources while addressing concerns about global climate change and related impacts attributed to increasing atmospheric concentrations of CO₂ (Peters et al., 2013). Fossil energy use with carbon capture utilization and storage is, therefore, an important part of a diversified energy portfolio that also includes use of fuels with reduced carbon intensity (e.g., renewables, nuclear, and natural gas) and development/deployment of energy conversion and utilization technologies with improved efficiency. Furthermore, CO₂ injected in an EOR-storage process may help to maintain pore pressure, thereby reducing the risk of induced seismicity that is a concern in large scale geologic storage of CO₂ in saline formations (Hitzman 2013, Zoback and Gorelick 2012, National Academy of Sciences 2012). The incremental oil recovery from CO₂ flooding is estimated to increase ultimate oil recovery by about 7-23% of the original oil-in-place (OOIP) (Jarrell et al., 2002), which makes CO₂ EOR and storage a potentially profitable process. Effective use of CO₂ for EOR and storage is possible through future energy policy and resource development planning based on the regional- and national-scale evaluation of the potential for the process (Orr, 2009; Godec et al., 2013).

High performance CO₂ floods can be achieved by optimum design of the injection process through accurate characterization of reservoir fluid and rock properties followed by detailed simulations. However, complex interaction of transport and phase behavior makes CO₂ floods difficult to model and simulate accurately. The EOR efficiency and CO₂ storage process are a function of how well CO₂ displaces oil from pores (local displacement efficiency), how much CO₂ is stored in pores (local storage efficiency), what portion of the reservoir fluid is contacted by injected CO₂ (sweep efficiency), and how well CO₂ will remain trapped in the reservoir. Gravity can overcome heterogeneity completely if the flooding process is gravity stable (Perry, 1982), greatly simplifying the process.

Oil is displaced by CO₂ at the pore level by mechanical displacement, development of miscibility, and oil swelling and viscosity reduction (Chung et al., 1988). The mass transfer of components between the gas and oil phases as miscibility is developed is the key for high efficiency of CO₂ floods (Johns et al, 1993; Orr, 2007). Miscibility can be achieved by increasing injection pressure above the minimum miscibility pressure (MMP) or enriching the injection gas with intermediate-weight hydrocarbons. However, the pressure required for miscibility should not be at pressures in excess of safe reservoir operational conditions (i.e., above fracture pressure), and there may be no pressure at which CO₂ miscibility is achieved with some heavy oils (Khorsandi et al., 2014). Achieving miscibility is not as critical for gravity stable or gravity assisted floods, however, since there is ample contact time for CO₂ to vaporize and swell the oil, and for film drainage to occur (Perry, 1982).

Injected CO₂ usually finds a shortcut or channel to production wells instead of uniformly sweeping the reservoir owing to high permeability paths or gravity tonguing. This is especially true when vertical wells are used because permeability tends to be layered orthogonal to the direction of flow. Well patterns are usually aligned optimally

with reservoir heterogeneity to maximize sweep efficiency, but early breakthrough cannot be avoided, just delayed. The impact of high permeability channels on flow is accentuated because CO₂ viscosity is much lower than the oil viscosity at the reservoir condition. Therefore CO₂ flows easier toward the production wells, increasing the mobility of the gas in the high permeability layers as flow occurs. Channeling becomes more severe for reservoirs with large permeability variations and greater longitudinal correlation lengths (Araktingi et al., 1993). As formations become more homogeneous and less impacted by gravity, viscous fingers can form also causing early breakthrough (Chang et al., 1994; Fayers and Newley, 1998; Christie et al., 1990). Gravity forces can also decrease sweep efficiency by pushing the injected fluid to the top or bottom of the reservoir depending on fluid density contrasts. Well pattern, well type, injection rate, and many other parameters can affect sweep efficiency as well. Sweep efficiency for CO₂ injection in vertical wells can be improved somewhat by using water-alternating-gas injection scheme, which decreases the effective mobility ratio, or by injection of more dense fluids (water) at the top of the reservoir or less dense fluids (gas) at the bottom (Salimi et al., 2012; Sobers et al., 2013). Estimation of sweep efficiency for field cases usually requires detailed simulation of flow in the reservoir.

CO₂ EOR is economically viable when CO₂ can be injected at relatively high flow rates producing significant incremental oil. Several factors influence injectivity of fluid into a well including reservoir permeability, relative permeability, injection well location with respect to flow barriers, injection well type, and reactions between the rock and injection fluids (Qiao et al., 2014; Cinar et al., 2009; Xiao et al., 2011; Spiteri et al., 2005). Horizontal wells have greater contact area with the reservoir compared to vertical wells, generally giving them greater injectivity when the injection rate is distributed evenly along the well (Ganjdanesh et al., 2014; Al-Khelaiwi and Davies, 2007). Flow into or out of horizontal wells, however, are more affected by unstable viscous fingering owing to less permeability variation longitudinally and flow tends to be larger near the heel of the well where pressure drops are greatest.

CO₂ can be trapped in the reservoir by various chemical and physical mechanisms. Physical trapping of CO₂ refers to the mechanisms that immobilize CO₂ as a free gas or supercritical fluid inside the porous media. For example, structural and stratigraphic trapping can occur, where the flow of CO₂ is impeded by a low-permeability barrier (Bachu et al., 1994). Conventional oil reservoirs are known to have structural and/or stratigraphic traps, although old wells can cause leakage. Another example of physical trapping is at the pore level, where capillary forces hold CO₂ inside the rock pores (Juanes et al., 2006). Capillary trapping can be achieved by injection of water behind CO₂ (Qi et al., 2007). CO₂ can also become dissolved in reservoir fluids or immobilized as a precipitated solid carbonate (Bachu et al., 1994; Metz et al. 2005). However, dissolution and precipitation of solids usually occurs over a much longer time scale compared to the production time.

Several methodologies have been developed to identify and screen suitable reservoirs for CO₂ flooding (Bachu et al. 2004, Taber et al. 1997a,b, Advanced Resources International, Inc., 2005). Zhang et al. (2010) estimated CO₂ storage capacity based on the assumption that the volume occupied by the oil will become available for CO₂. Wood et al. (2008) developed dimensionless groups for continuous gravity-stable CO₂ flooding of homogeneous reservoirs with high vertical permeabilities and large dip angles. They estimated oil recovery and CO₂ storage curves for this process using injection and production from vertical wells. Heterogeneities were not included because the gas-oil interface during injection was assumed to be perfectly horizontal as it moved downward (completely gravity stable flow). Zhou et al. (1997) studied the scaling groups for multiphase flow in simple heterogeneous reservoirs.

This research was motivated as a part of U.S. DOE's Carbon Storage program, which aims to develop and advance technologies to capture, utilize, and geologically store significant quantities of CO₂. This paper describes the evaluation of a next-generation CO₂-EOR flooding scheme that has the potential to utilize relatively large volumes of CO₂ to improve incremental recovery of oil, while concomitantly enhancing volumetric CO₂ storage efficiency.

The paper is organized as follows. First, the model is described including the horizontal well pattern, reservoir properties, assumptions, and equations. Next, example simulations are given to demonstrate the significant potential of the approach for a wide variety of reservoirs, including those in the offshore environment and reservoirs with horizontal, but intermittent shale layers. WAG floods are compared to the proposed alternative process. Response surface functions are then developed based on derived dimensionless scaling groups using inspectional analysis. This approach is taken to provide a proxy model for probabilistic assessments of the likely ranges for oil recoveries and CO₂ storage efficiencies for all possible reservoir parameter combinations. Monte-Carlo simulations of the response functions are made to develop these assessments.

2. Reservoir model

First-contact miscible (FCM) CO₂ injection is made in a non-dipping reservoir where gravity forces enhance both recovery and CO₂ storage. **Figure 1** shows the 3D horizontal well pattern used, where reservoir oil is displaced

downward towards the horizontal producer at the bottom and opposite corner in a staggered horizontal line drive pattern (see **Figure 2**). This well configuration was found to be optimum for recovery and storage by comparison to other patterns, such as switching the location of the horizontal injector and producer, and aligning the horizontal wells vertically. The pressures at the horizontal injection and producing wells are kept constant during the entire CO₂ injection process. Early breakthrough either from down coning, fingering, or channeling reduces the displacement efficiency of the injected CO₂ to sweep the oil. Injecting CO₂ in a gravity-enhanced process is potentially beneficial as it delays breakthrough time, which improves both high volumetric sweep and high microscopic sweep (Lake et al., 2014). The 2-D vertical cross-sectional model is generally used in this paper as shown in Fig. 1, unless otherwise specified. The 2-D model is representative of a continuous pattern of horizontal injection and production wells, which create approximate no-flow boundaries as illustrated in Fig. 2.

Figure 1: 3-D reservoir and horizontal well locations and a corresponding cross-sectional 2-D reservoir with two horizontal wells at the corners.

Figure 2: Illustration of staggered line-drive pattern using multiple injection and production horizontal wells. The 3-D reservoir block and horizontal well locations are also illustrated in Fig. 1 based on the approximate no-flow boundaries that result.

Several additional assumptions were made to simplify the governing equations. Only the aqueous and hydrocarbon phases are flowing owing to the FCM assumption. That is, the resident oil and injected CO₂ are assumed to always be miscible. Miscibility is an excellent assumption if the minimum miscibility pressure is exceeded (Lake et al., 2014). Further, the semi-gravity stable process gives ample time for efficient extraction or for film drainage to occur. Besides the assumption of two-phase flow, flow in the 2-D cross-section model is incompressible. Incompressibility is also a reasonable assumption since both water, oil, and CO₂ are relatively incompressible at most reservoir pressures. Chemical reactions and adsorption are also neglected, and porosity is constant with time, but is allowed to vary spatially. Permeability varies significantly within the reservoir. The injection and production wells are constant pressure horizontal wells, where the pressures can vary to change CO₂

injectivity. The boundaries of the reservoir are no flow and the horizontal wells are placed close to those boundaries. These boundaries are based on symmetry of streamlines (see Figs. 1 and 2). The alternative injection process relies on little water influx from any aquifer below, which is common in petroleum reservoirs.

CO₂ dissolution in water is not modeled because the volume of CO₂ stored by displacement of fluids (water and oil) dwarfs the volume stored by CO₂ dissolution (Orr 2009). CO₂ dissolution, however, can be important in WAG injection where unsaturated water is injected in multiple cycles.

With these assumptions, the governing equations become,

$$\phi \frac{\partial S_w}{\partial t} + \frac{\partial u_{wx}}{\partial x} + \frac{\partial u_{wz}}{\partial z} = 0, \quad (1)$$

$$\phi \frac{\partial (S_h c_{ih})}{\partial t} + \frac{\partial (c_{ih} u_{hx})}{\partial x} + \frac{\partial (c_{ih} u_{hz})}{\partial z} = 0 \quad i = 1, \dots, Nc, \quad (2)$$

where S is phase saturation, subscripts w and h indicate water and hydrocarbon phases, u is phase velocity, c_{ih} is concentration of component i in the hydrocarbon phase, x and z are horizontal and vertical directions, and t is time. Conservation of total mass under the assumption of incompressibility gives the continuity equation,

$$\frac{\partial u_{wx}}{\partial x} + \frac{\partial u_{wz}}{\partial z} + \frac{\partial u_{hx}}{\partial x} + \frac{\partial u_{hz}}{\partial z} = 0, \quad (3)$$

The velocities are calculated using Darcies law in the x- and z-directions:

$$u_{jx} = -\frac{k_x k_{rj}}{\mu_j} \left(\frac{\partial P_j}{\partial x} \right), \quad j = h, w. \quad (4)$$

$$u_{jz} = -\frac{k_z k_{rj}}{\mu_j} \left(\frac{\partial P_j}{\partial z} + \rho_j g \right), \quad j = h, w. \quad (5)$$

where the hydrocarbon phase viscosity is given by (Garmeh 2009),

$$\mu_h = [\mu_o^{-1/4} + \beta(\mu_g^{-1/4} - \mu_o^{-1/4})]^{-4}, \quad (6)$$

with $\beta = \frac{c_1 - c_1^J}{c_1^J - c_1^I}$ and ‘1’ representing the injection component.

The Corey’s relative permeability model is used. Because of the FCM assumption, the maximum number of phases present is two and,

$$k_{rj} = k_{rj}^o \left(\frac{S_j - S_{jr}}{1 - S_{wr} - S_{hr}} \right)^{n_j}, \quad j = h, w. \quad (7)$$

Finally we have the auxiliary equations:

$$\sum_{i=1}^{Nc} c_{ij} = 1 \quad i = 1, \dots, Nc, j = h, \quad (8)$$

$$S_w + S_h = 1. \quad (9)$$

Phase pressures are related by capillary pressure, which is scaled using the Leverett J-function. Water is assumed to

be the wetting phase.

$$P_h = P_w + P_c, \quad (10)$$

$$P_c = \sigma \sqrt{\frac{\phi}{k_x}} j(S_w) . \quad (11)$$

3. Simulation Model and Example Results

The Computer Modelling Groups' CMG-GEM is used to model compositional flow across the 3-D and 2-D vertical cross-section illustrated in Fig. 1. The dimensionless oil recovery at any given time is taken to be the fraction of the original mass of oil in place that has been recovered. Oil recovery is usually reported in barrels, but because CO₂ is highly soluble in oil the volumetric recovery is dependent on whether or not a separator is used, and if the separator is operated at the optimum pressure. This unnecessary complexity is avoided by only reporting recoveries in terms of mass fractions. The recovery curves in terms of mass or volume are very similar when proper separator conditions are used as the optimum is a function of the oil composition.

Stored CO₂ volume is calculated as the difference between the reservoir volume of CO₂ injected and produced. The CO₂ storage efficiency is therefore the stored CO₂ volume (at reservoir conditions) divided by moveable pore volume. The storage efficiency is 100% when all of the pore space is filled only with CO₂ and immobile water (oil has been completely vaporized and produced). Moveable pore volumes injected (MPVI) is used as the dimensionless time scale, where $MPVI = PVI / (1 - S_{wirr})$. MPVI is advantageous to use for CO₂ storage in oil reservoirs because it represents the maximum possible volume available for CO₂ storage. MPVI is a commonly used parameter in reservoir engineering (Lake et al. 2014).

Permeabilities and porosities in the model are generated using stochastic random generation (Jennings et al., 2000). Horizontal permeability is assumed to be independent of direction. Horizontal permeability is generated first, followed by vertical permeability. Vertical permeability is calculated based on the vertical to horizontal permeability ratio. Porosity and permeability are functions of pore structure, and are therefore assumed to be related. The simplified form of the Carmen-Kozeny equation is used here to relate porosity and permeability (Fitts, 2002),

$$k = \frac{\phi^3}{(1-\phi)^2} \left(\frac{d_g^2}{180} \right), \quad (12)$$

where k is permeability, ϕ is the porosity, and d_g is the grain diameter. For simplicity the grain diameter is assumed constant for all models (500 μ m).

Hydrocarbon phase density is calculated using the Peng-Robinson equation of state (EOS) (Peng and Robinson, 1976). Two different oils with two and eleven components are modeled with the EOS parameters given in **Tables 1** and **2**. Oil and gas viscosities are a function of phase compositions and component viscosities using the quarter-power mixing rule (Lake et al. 2014). Two-phase relative permeability curves are generated by Corey's model, as described previously.

Fluid properties with the EOS are a function of reservoir temperature and pressure. The average reservoir pressure is relatively constant in the simulations. Based on standard gradients with depth, the following geothermal equation for the pressure and temperature relationship (Lake *et al.* 2014) is used:

$$\begin{aligned} P(\text{psia}) &= 0.465D_z(\text{ft}) + 14.7 \\ T(F) &= 0.014286D_z(\text{ft}) + 60 \end{aligned} \quad (13)$$

Equation (13) typically leads to relatively constant viscosity and density of CO₂ with depth. For example, CO₂ viscosity is around 0.06 cp for most practical reservoir conditions.

As described previously, CO₂ is assumed to be FCM with the oil. However, field experience suggests that displacements are usually MCM with dynamic vaporization and condensation of components (Zick, 1986). Simulation of MCM requires time consuming phase equilibria calculations, which are not generally required for

FCM flow. This assumption was tested in this research by comparison with MCM flow, where the pressure was above the MMP. MMPs were calculated using PennPVT (PennPVT toolkit, 2013) for the two and eleven component oils to be 1,348+/-1.2 psia and 2,281+/-47.1 psia, respectively. These pressures were always exceeded in the simulations.

Table 1: Composition of oil and fluid properties for 11-component model (Egwuenu et al., 2008)

Component	Oil Composition (mol %)	Properties			BIPs	
		T_c (°F)	P_c (psia)	Ω	CO ₂	C ₁
CO ₂	0.10	87.62	1,071.34	0.225	-	-
C ₁	34.67	-116.58	667.80	0.010	0.100	-
C ₂	3.13	89.72	708.40	0.099	0.130	-
C ₃	3.96	205.82	617.40	0.152	0.135	-
C ₄	5.95	294.60	543.30	0.187	0.130	-
C ₅	4.06	366.52	475.30	0.252	0.130	-
C ₆	3.06	453.92	431.00	0.296	0.140	0.020
C ₇	4.95	512.92	397.00	0.351	0.140	0.030
C ₈₊	4.97	564.42	264.00	0.394	0.140	0.035
C ₁₀₊	30.11	647.62	320.00	0.491	0.140	0.040
C ₁₄₊	50.40	790.02	230.00	0.755	0.140	0.060

Table 2: Composition of oil and fluid properties for two-component oil

Component	Oil Composition (mol %)	Properties			BIPs	
		T_c (°F)	P_c (psia)	ω	CO ₂	C ₁
CO ₂	0.0	87.62	1071.34	0.225	-	-
C ₁	10.0	-116.58	667.80	0.008	0.100	-
C ₅	90.0	366.52	475.30	0.252	0.130	0.000

Example simulation results are presented here to demonstrate the potential of the alternative process, but also to examine several special cases. One set of simulations was made to explore the validity of using a 2-D cross-sectional model instead of a full 3-D model. A 64×64×16 grid was used for the 3-D simulations. For most simulations, the 2-D model is divided into 1024 grid blocks, including 64 x-direction and 16 z-direction grid blocks. This is the base case grid. Additional 2-D grids of 128×32, and 32×8 in the x- and z-directions, respectively, were also considered. Two 3D models were examined. The model referred to as the 3D-1 model uses the same staggered line drive model as shown in Figures 1 and 2, while 3D-2 places the horizontal wells directly over each other (not staggered).

Comparisons of the results from the 3-D and 2-D models are presented in **Figures 3 and 4** for the case where permeability varies significantly. The Dykstra-parsons coefficient is 0.6, while the dimensionless correlation lengths are 1.0 in the x- and y- directions, and 0.1 in the vertical. The dimensionless correlation length is the correlation length divided by either the horizontal or vertical distances of the model. The 3D-1 model represented in Figure 1 matches well the oil recovery curves predicted using the 2-D reservoir model with two horizontal wells also at the corners. Further, the oil recovery and CO₂ storage efficiency curves predicted using 128×32 and 32×8 grid blocks were compared with the base case studied here using 64×16 (2D - FCM) grid blocks. The results demonstrate that it is reasonable to use 64×16 grid blocks, but also demonstrate the significant potential in storing CO₂ and recovery oil. **Figure 5** shows the CO₂ concentration and water saturation contours for one of the 2-D cross-section models with initial water saturation equal to 0.525 and immobile water saturation of 0.40. It is clear that the CO₂ injection process in Fig. 5 is not close to being gravity stable (interfaces are not flat). However, gravity delays CO₂ breakthrough and oil cuts remain high even after breakthrough of CO₂. CO₂ is coned downward to the production well.

The 3D-2 case with no well staggering gives poorer recovery and storage owing to a smaller distance between wells. A smaller distance between wells increasing the viscous forces and gives quicker CO_2 breakthrough. The staggered-line drive pattern is superior in all cases studied and is used in the rest of this paper.

The oil recovery and CO_2 storage efficiency curves predicted assuming MCM and FCM displacements were also compared and found to agree well (see Figs. 3 and 4). MCM is modeled with the eleven-component oil. The results verify, at least for the case studied herein, that the assumption of FCM is reasonable. It is likely that even immiscible floods can perform well in this horizontal well configuration if the spreading coefficient between water, oil, and CO_2 is positive (Zhou and Blunt, 1997). As explained previously, a positive spreading coefficient can cause film drainage of oil by gravity, leading to high extraction efficiency.

The two-component oil is used in the remainder of the paper to model FCM flow since the scaling groups, as developed in Section 4, can be more easily calculated and the simulations are much faster. Using only two components to represent the oil is a good assumption under FCM flow. Any variations in densities and viscosities for different fluids are explicitly accounted for in the scaling groups.

Figure 3: Oil recovery comparisons for 3-D and 2-D reservoirs, FCM and MCM, and different numbers of grid blocks.

Figure 4: CO_2 storage efficiency (% MPVI) for 3-D and 2-D reservoirs, FCM and MCM, and different numbers of grid blocks.

Figure 5: CO_2 mole fraction in the hydrocarbon phase and water saturations at 0.2, 0.5 and 1.2 MPVI. CO_2 breakthrough occurs at about 0.85 MPVI, which gives a very efficient displacement and storage efficiency.

The gravity-assisted process could also be significantly impacted by vertical permeability. Vertical permeability in oil reservoirs is typically less than horizontal permeability owing to grain anisotropy, but can also be reduced at macroscopic scale when shale laminations or other geologic features that restrict vertical flow are present. In **Figure 6**, the effect of thin, but discontinuous and intermittent shale laminae is considered. The thin shales are modeled in GEM by making the vertical transmissibility zero along the solid bold lines in Figure 6. In the first configuration (shale-1), shale layers exist as shown by both the black and red lines, while for the second configuration (shale-2) the small single shale streak represented by the red line is removed. This shale, although small in length, is just above the perforated production well. The oil recoveries and CO₂ storage efficiencies for the two-shale configurations are shown in **Figures 7 and 8**. The results show that the presence of shale layers could result in lower oil recovery, although recovery is still very good for both cases. The shale-2 case actually shows greater recovery than when shale laminae are not present. The recovery is somewhat lower, however, for the shale-1 case where flow to the perforations in the production well is restricted (with perforations just below a shale). Still, the overall recovery and storage is excellent. These figures also show that the effect of shale layers on reducing CO₂ storage efficiency is somewhat less than their impact on oil recovery. The reason for this is that the shales provide a local trap that inhibits vertical migration of CO₂ causing CO₂ to spread out more laterally in the reservoir.

If a shale layer existed across the entire model, recoveries and CO₂ storage in the gravity-assisted process would be significantly diminished. The injection scheme modeled here relies on some (but potentially limited) vertical permeability so that continuity exists from the injector to the production well. Shale laminae are not considered in the rest of the paper as the reservoir is assumed to be continuous. Reservoirs separated by a single shale or tight streak would have to be handled as separate compartments, each requiring their own injectors and producers. The decision to exploit an individual compartment would then be based on economics.

The recoveries and storage efficiencies of the gravity-assisted process were also compared to standard water-alternating-gas (WAG) schemes using vertical wells. A three-cycle WAG injection process with a WAG ratio of 1:1 (one volume of water to one volume of gas in each cycle) was performed based on a 2-D model (64×16 grid blocks). We used Land's equation to model the gas phase hysteresis for WAG (Lands 1968). Land's model was not used in the continuous CO₂ injection case since little CO₂ would be trapped. Wells were vertical for WAG, but not for the assisted gravity process. The perforations in the vertical injection well for WAG were located in the top 1/4th of the model, while the perforations in the vertical production well were only in the lower 1/4th of the well. The perforation locations were designed to maximize recovery from WAG.

Figure 6: Two different shale layer configurations for the 2-D reservoirs. Shale layers are represented by the bold black or red lines. The first configuration includes both black and red lines. The second configuration includes only the shales given by the black lines (small red shale is removed).

Figure 7: Oil recovery comparisons for different shale layer configurations.

Figure 8: CO₂ storage efficiency (% MPVI) for different shale layer configurations.

Figure 9: Oil recovery comparison for continuous CO₂ and WAG injection processes for initial oil saturations equal to residual hydrocarbon saturation and also for the case with initially mobile oil.

Figure 10: CO₂ storage efficiency (% MPVI) for continuous CO₂ and WAG injection processes at residual and above residual hydrocarbon saturations.

Figure 11: Water produced (% MPVI) for continuous CO₂ and WAG injection processes at residual and above residual hydrocarbon saturations.

Figures 9 and 10 give the oil recovery and CO₂ storage efficiency curves predicted for the three-cycle WAG injection using vertical wells and the gravity-assisted process with staggered line-drive horizontal wells. Oil recovery and CO₂ storage is significantly greater using the staggered-line drive pattern for both values of initial oil saturation.

Figure 11 shows the volume of produced water at the surface per moveable pore volume for continuous CO₂ (horizontal wells using the gravity-assisted process) and WAG injection (vertical wells). As shown, WAG produces significantly more water largely because water is injected to improve the mobility ratio. Some of this water could be reinjected after treatment. The gravity-assisted process with continuous CO₂ injection, however, only produces the initial mobile water. The treatment costs are likely significantly greater in the WAG case than for continuous CO₂ injection. One disadvantage potentially, however, is the management and associated costs of disposing of produced brine, since only CO₂ is injected continuously in this alternative process. If the gravity assisted process was used for secondary recovery (without a prior water flood), the volume of water produced would be significantly lower. Injection of gas for secondary recovery carries more risk since the investment costs would be much greater than if a waterflood were performed.

4. Scaling groups

The previous section demonstrated the significant potential of the gravity-assisted process using horizontal wells in a staggered-line drive pattern. This section presents the key scaling groups associated with the governing equations and boundary conditions so that all possible reservoir and fluid parameters can be described with the least number of simulations.

Inspectional analysis has been commonly used to derive key scaling groups in a process where the governing equations and initial/boundary conditions are known (Shook et al. 1992). Appendix A outlines the basic steps used

in inspectional analysis for deriving the scaling groups. For the equations in this paper, eight independent scaling groups result. Inspectional analysis, however, cannot account for heterogeneity since permeability variations are not explicitly in the equations. Thus, the effect of reservoir heterogeneity is represented using three additional dimensionless groups: the Dykstra-Parson coefficient and the correlation lengths in the vertical and horizontal directions. The final 11 groups therefore are:

1	R_L	$= \frac{L}{H} \sqrt{\frac{k_z}{k_x}}$	Effective aspect ratio
2	V_{DP}		Dykstra-Parsons coefficient
3	λ_{Dx}		Correlation length coefficient in x -direction
4	λ_{Dz}		Correlation length coefficient in z -direction
5	M_g^o	$= \frac{\mu_o}{\mu_g}$	Mobility ratio (CO ₂ -oil)
6	NR_g^o	$= \frac{\rho_o - \rho_g}{\rho_w - \rho_o}$	Buoyancy ratio
7	N_o^w	$= \frac{H(\rho_o - \rho_w)g}{P_p - P_{inj}}$	Buoyancy number
8	S_{oiD}	$= \frac{1 - S_{hr} - S_{wi}}{1 - S_{hr} - S_{wr}}$	Normalized initial oil saturation
9	M_w^o	$= \frac{\mu_o}{\mu_w} \frac{k_{rw}^o}{k_{ro}^o}$	Mobility ratio (water-oil)
10	S_{hr}		Residual hydrocarbon saturation
11	S_{wr}		Residual water saturation

The first four scaling groups describe reservoir structure and rock properties. The effective aspect ratio takes into consideration both the length to height ratio and the vertical to horizontal permeability ratio; it is a measure of the rate of fluid communication in the horizontal direction to that in the vertical direction. L and H are the horizontal and vertical distance between injection and production wells. The flow characteristics, like viscous fingering, and channeling, depend primarily on the permeability heterogeneity of the reservoir. The degree of permeability variance (Dykstra-Parsons coefficient) and the correlation lengths are important parameters to characterize reservoir heterogeneity (Lake et al., 2014). The Dykstra-Parsons coefficient is equal to 0.0 for a homogeneous reservoir, and 1.0 for a completely heterogeneous one. Random permeabilities spatially are given by a zero correlation length, while a layer-cake model has an infinite correlation length. Most fields have Dykstra-Parson's coefficients in the range of 0.4 to 0.9, and correlation lengths on the order of the well spacing (say 100 – 2000 ft).

Different permeability and porosity realizations are possible for one set of these heterogeneity scaling groups so that recoveries and storage efficiencies can be quite variable. Therefore all simulations were repeated in this paper using 30 different realizations of permeability (and corresponding porosities). The results were then averaged to give a better representation of the trend in recoveries and storage efficiencies with heterogeneity. **Figure 12** shows an example of the effect of stochastically different permeability fields on oil recovery at 1.2 MPVI. The fluctuation of averaged oil recovery becomes less significant as the number of realizations increases.

Figure 12: Example of effect of stochastic properties on oil recovery at 1.2 MPVI. The x-axis is the number of realizations used in averaging.

Scaling groups 5 and 6 represent fluid properties. The mobility ratio is the ratio of the displacing phase (CO_2) to the mobility of the displaced phase (oil). It directly relates to oil recovery, especially for vertical wells where channeling dominates. The buoyancy ratio is used to account for the ratio of the density difference between CO_2 and oil to the density difference between water and oil. The buoyancy number is the ratio of the gravity force to the pressure difference between injector and producer, where a large value indicates large density differences between water and oil, resulting in high potential for fluid segregation and small sweep efficiency.

Scaling groups 7 to 11 relate to the interaction of rock and fluid in pores. The normalized initial oil saturation S_{oiD} plays a large role in the presence or absence of mobile oil at the beginning of the CO_2 injection process. Oil is mobile when the initial oil saturation is greater than the residual oil saturation.

The low and high values of each scaling group considered in this paper are presented in **Table 3**, where the some of the input parameters to calculate the scaling groups are from Wood et al., (2008). In some cases, decisions regarding the ranges were made where reliable data were not available. The bounding values were required for each group to perform experimental design using a Latin hypercube sampling, and later in doing Monte Carlo simulation.

Table 3: Range of scaling group values

	R_L	V_{DP}	λ_{Dx}	λ_{Dz}	M_g^o	NR_g^o	S_{oiD}	M_w^o	N_o^w	S_{hr}	S_{wr}
Low	0.1	0.4	0.1	0.01	1	0.1	0	0.4	0.001	0.1	0.2
High	10	0.9	10	1	10	1	1	4	0.1	0.6	0.6

5. Sensitivity Analysis and Validation of Scaling Groups

The 2D vertical cross-section described in Fig. 1 was used to study the effect of each scaling group on recovery and storage efficiency. The effects of capillary forces and dispersion were secondary effects in this model and were not included in the scaling, although some numerical dispersion is present (64×16 grid blocks were used). If properly done, the same values of the scaling groups should yield similar oil recoveries and storage efficiencies even when input reservoir properties are quite different. **Appendix B** shows an example validation of the scaling groups for three different reservoirs, but with the same scaling groups.

Sensitivity tests were made by comparing the relative importance of scaling groups as represented by tornado diagrams shown in **Figures 13 and 14**. An initial reservoir pressure of 4550 psia (31.4 MPa) was selected, while the temperature was held at 200°F (93°C). The results in this paper can still be used even for pressures and temperatures different from these values because these parameters impact densities and viscosities, which are accounted for in the scaling groups. The only restriction is that the MMP must be exceeded, although near miscibility will likely lead to similar recoveries and storage coefficients as are presented here.

Figure 13: Tornado chart of scaling groups for oil mass recovery at 1.2 MPVI.

Figure 14: Tornado chart of scaling groups for CO₂ storage efficiency (% MPVI) at 1.2 MPVI.

The tornado charts in Figs. 13 and 14 show the parameters that are most important to recovery and storage using the alternative EOR-storage process. For each uncertainty considered, the top bar in the figures represents the scaling group that contributes the most to the variability of the outcome. As shown, the CO₂-oil mobility ratio and effective aspect ratio are the two most sensitive scaling groups for both oil recovery and storage. The oil recovery and CO₂ storage efficiency shown in solid and upward diagonal bars are calculated using the high and low value of each scaling group, respectively. For example, an increase in M_g^o leads to a lower oil recovery, as shown in **Figure 13**.

6. Response surfaces

An important step toward making probabilistic forecasts is to develop an accurate model that can quickly estimate recovery and storage values for a variety of reservoirs and fluid properties. A functional relationship between scaling groups, which is also known as a response surface, is developed for both recovery and storage using the CO₂-drive enhanced-gravity process. The response surfaces can also be used for screening of candidate reservoirs.

Two common options for experimental design are Box-Behnken (BB) (Box and Behnken, 1960) and Latin Hypercube sampling (LHS) (McKay et al., 1979; Stein, 1987). BB experimental design is a three-point design method to build a quadratic response surface, and LHS is a multi-point design method, which can be used to build a higher-order model with many input parameters. An example application using BB design is presented by Li et al. (2014). Different from BB, LHS design assumes that computations have no random error. Thus, the computer experiments are repeatable and the results have no component of random error (contrary to physical experiments). Giunta et al. (2003) showed that modern experimental design techniques such as LHS provide better estimates from computer experiments.

LHS can be configured for any number of samples and is not restricted to sample sizes that are specific multiples or powers of design parameters. It distributes the points randomly in multi-dimensional parameter space. Therefore, even with a limited number of design experiments, LHS can be used for high-dimensional design. The sample size n_{LHS} in an LHS is calculated from Eq. (14) (Osterloh et al., 2013).

$$n_{LHS} = \alpha [(N+1)(N+2)/2] \quad \alpha = 1 \text{ to } 1.5. \quad (14)$$

For the application in this paper, the factor α in Eq. (14) was chosen to be 1.5. Based on LHS, reservoirs with various combinations of values for each of the scaling groups were generated for a total of 117 experiments where each experiment was the average of 30 simulations. Thus, over 3,500 simulations were made to develop the response surfaces. For statistical purposes, the scaling group values were linearly normalized within the range from -1 to +1 using Eq. (15).

$$\bar{X} = -1 + 2(X - L)/(H - L), \quad (15)$$

where $\bar{X}$ is the normalized value of the group, X is the group value to be normalized, and H and L are the high and low values for the groups as listed in Table 3.

The results from the prescribed simulations were used to generate response surfaces for each recovery and

storage efficiency parameter in the screening model. Response surface fits include constant, linear, interaction and quadratic effects of the following form:

$$\text{Parameter} = c_0 + \quad (16)$$

$$\begin{aligned} & c_1x_1 + c_2x_2 + c_3x_3 + \dots + c_9x_9 + c_{10}x_{10} + c_{11}x_{11} + \\ & c_{12}x_1x_2 + c_{13}x_1x_3 + c_{14}x_1x_4 + \dots + c_{21}x_1x_{11} + \dots + c_{66}x_{10}x_{11} + \\ & c_{67}x_1^2 + c_{68}x_2^2 + c_{69}x_3^2 + \dots + c_{77}x_{11}^2 \end{aligned}$$

where:

c – coefficient,
 x – scaling groups.

Values of the 78 coefficients were determined to model the results of oil recovery and CO₂ storage potential for a given reservoir. Response functions were developed for five values of oil mass recovery and CO₂ storage efficiency at 0.25, 0.75, 1.2, and 2 MPVI, respectively; and at CO₂ breakthrough time. The magnitude of the coefficients and Pareto chart can be used to identify which scaling groups are most important and if some could be neglected to minimize the number of coefficients. The Akaike Information Criterion (AIC), however, was used to determine the optimum response surface with a minimum number of the most important coefficients. First the response surface was fit with all of the 78 constant, linear, interaction and quadratic coefficients. The next step was to determine the least important coefficient, which is the coefficient with the smallest absolute value of the normalized scaling groups. A new response surface can then be fit. This elimination approach continues until there is only one coefficient left. The AIC score is calculated for each model and the model with the lowest AIC score is selected. The corrected form of AIC (Cavanaugh, 1997), as shown in Eq. (17), was used since the number of experiments is small when compared to the number of coefficients. That is,

$$AIC_c(df) = \frac{n}{2} \log(2\pi MSE) + \frac{n}{2} + \frac{n(k+2)}{n-k-3}, \quad (17)$$

where n is sample size and k is the number of parameters in the model. The AIC scores for oil mass recovery factor and CO₂ storage efficiency from the LHS experimental design are shown in **Figures 15** and **16**, respectively.

Figure 15: AIC score using the LHS design for different response surface functions (see Eq. (17)) of the oil recoveries at various MPVI.

Figure 16: AIC score using the LHS design for different response surface functions (see Eq. (17)) of the breakthrough time and CO₂ storage efficiencies (% MPVI).

The number of coefficients was reduced from 78 in the initial LHC fit to an average of ten for each response surface function using the AIC criterion. The storage efficiency at 0.25 MPVI is the same for all reservoirs, and AIC score is at minimum for the storage model at 0.25 MPVI using only one parameter. The reduced response surface fits for oil recovery efficiencies, CO₂ storage at breakthrough time, and CO₂ storage efficiencies are given in **Appendix C**.

In Eqs. (C-1) to (C-9), negative coefficients of the normalized dimensionless groups indicate that these groups are inversely related to storage and oil recovery, while positive coefficients suggest these groups are positively correlated to oil recovery or CO₂ storage efficiency. **Figures 17** and **18** show the validation of the reduced response

function obtained from LHS (see Eqs. (C-1) to (C-9) in Appendix C).

The actual simulation results for test cases are compared with those calculated using reduced response surface functions from LHS (Eqs. (C-1) to (C-9)). The test values were determined from simulations using the values of the normalized scaling groups with Box-Behnken design. Thus, the test data consisted of 188 experiments for the 11 scaling groups (simulations were repeated 30 times and averaged as before). The predicted and actual predictions in Figures 17 and 18 lie close to the equal value line, as indicated by the excellent R-square fits. Li et al. (2014) compare LHS and BB designs and showed that LHS is more accurate.

Figure 17: Validation of predicted oil recovery using reduced response functions obtained from LHS simulations as shown in Eqs. (C-1)-(C-4). The predicted value is compared with the actual simulation result performed by BB experimental design.

Figure 18: Validation of predicted CO₂ storage efficiency (% MPVI) using reduced response functions obtained from LHS simulations as shown in Eqs. (C-5)-(C-9). The predicted value is compared with the actual simulation result performed by BB experimental design.

7. Monte Carlo simulation for probabilistic forecasts

Monte Carlo sampling was used to calculate the modeled response values over the range of the scaling groups given in Table 3. The response surfaces developed in Section 6 were used as proxy models for the recoveries so that numerous sampling could be made.

Monte Carlo simulations were carried out over the normalized ranges of scaling parameters using 100,000 samples. Probabilistic parameters are assumed to be normally distributed based on the input ranges of the scaling groups, where the low and high values define two-standard deviations. The resulting Monte Carlo distributions are shown in **Figures 19 and 20** for oil recovery and CO₂ storage efficiency, respectively. The early recovery is very sensitive to the difference between initial and residual oil saturation, but the sensitivity does not increase as injection proceeds. The distribution for CO₂ storage efficiency is a single value at 0.25 MPVI because breakthrough had not yet occurred in any reservoir. Thus, storage is equal to the volume injected. The distributions at the various dimensionless times (MPVI) show that the process is very robust and highly efficient. After 2.0 MPVI, CO₂ storage efficiency varies from about 81 to 93% over two-standard deviations indicating that nearly all of the available pore space (excluding immobile water) at the end of injection is occupied by CO₂. Likewise, oil recoveries after 2.0 MPVI varied from 79% to 93% of the original mass of oil-in-place (OOIP). No other recovery or storage process, except for a gravity stable flood, has values close to these.

Figure 19: Oil recovery distribution predicted by the Monte Carlo method using the response surface function of Eq. (16) and the coefficients from LHS. Input scaling groups are normalized and assumed to have a normal distribution. A total of 100,000 samples are made.

Figure 20: CO₂ storage efficiency (% MPVI) distribution predicted by the Monte Carlo method using the response surface function of Eq. (16) with coefficients from LHS. Input scaling groups are normalized and assumed to have a normal distribution. A total of 100,000 samples are made.

Next, the 10th/50th/90th percentile (P10/P50/P90) results were determined from the Monte Carlo distributions. The estimated P90 recovery shows that there is a 90% chance the recovery will be achieved. Similar definitions can be applied to the P50 and P10 recovery. **Figures 21 and 22** show the oil recovery profiles that correspond to the P90, P50, and P10 scenario of the case, respectively. Again, these curves show that the process is very robust and highly efficient.

Figure 21: Estimated P10/P50/P90 of oil recovery based on Monte Carlo distribution using the response surface function predicted by LHS.

Figure 22: Estimated P10/P50/P90 of CO₂ storage efficiency (% MPVI) based on Monte Carlo distribution using the response surface function predicted by LHS.

8. Conclusions

High volumetric CO₂ storage and incremental oil recovery can be achieved compared to standard WAG in a 40 acre five spot when using the gravity-assisted process. The process relies on optimum placement of horizontal and vertical wells in a staggered line-drive pattern. The approach could be applied to conventional onshore pay intervals, but also ROZ zones (residual-oil zones), and offshore oil fields, especially when wells have not yet been drilled. Other key conclusions are:

- Recoveries and storage efficiencies are nearly always greater than 80% for all reservoirs considered based on FCM flow and the gravity-assisted process.
- The gravity assisted process relies on having a reservoir with little or no water influx. A strong aquifer cannot be effectively drained.

- A total of 11 scaling groups were found to model accurately storage and oil recovery.
- Latin hypercube sampling (LHS) was used to generate the response functions for both oil recovery and CO₂ storage efficiency based on the 11 scaling groups.
- The response functions from LHS were highly accurate with R-square values greater than 0.92. These response functions were used as proxy models for Monte Carlo simulation.
- Monte Carlo distributions and P10/P50/P90 curves showed that the gravity assisted process is highly robust in that the P10 to P90 values were very close to each other.
- The response surfaces can also be used as screening models for large databases of reservoirs to determine the most attractive CO₂ EOR and storage candidates. By controlling the operational parameters, the screening model could also be used to optimize oil recovery and/or CO₂ storage efficiency.

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Appendix A – Derivation of scaling groups

Inspectional analysis is used to derive the key scaling groups from the governing equations of Eqs. (1)-(11) and the initial and boundary conditions. The initial and boundary conditions in their dimensional form are:

$$\begin{array}{llll}
 S_h = S_h^I & \text{At} & t = 0 & \forall x, z \\
 c_{ih} = c_{ih}^I & \text{At} & t = 0 & \forall x, z \\
 c_{ih} = c_{ih}^J & \text{At} & x = 0 & \forall t, z \\
 P_w = P_h = P_{mj} & \text{At} & x = L, z = H & \forall t \\
 P_w = P_h = P_p & \text{At} & x = 0, z = 0 & \forall t
 \end{array}$$

$$\begin{array}{llll}
u_{wx} = 0 & \text{At} & x = 0 & \forall z, t \\
u_{wx} = 0 & \text{At} & x = L & \forall z, t \\
u_{hx} = 0 & \text{At} & x = 0 & \forall z, t \\
u_{hx} = 0 & \text{At} & x = L & \forall z, t \\
u_{wz} = 0 & \text{At} & z = 0 & \forall x, t \\
u_{wz} = 0 & \text{At} & z = H & \forall x, t \\
u_{hz} = 0 & \text{At} & z = 0 & \forall x, t \\
u_{hz} = 0 & \text{At} & z = H & \forall x, t
\end{array} \tag{A-1}$$

Two arbitrary scaling factors are introduced for each variable assuming a linear relationship. That is, the dimensionless variable is transformed to dimensional space using,

$$v = v^{2*} v_D + v^{1*} \tag{A-2}$$

where v is a vector of variables, i.e. $S_h, S_w, u_{wx}, u_{wz}, u_{hx}, u_{hz}, c_{ih}, x, z, t, P_w$ and P_h . The dimensionless variables given by Eqs. (A-2) are then substituted into the boundary conditions. For example, the dimensionless hydrocarbon saturation boundary condition would yield,

$$S_{hD} = \frac{S_h^I - S_h^{1*}}{S_h^{2*}} \quad \text{At} \quad t_D = -\frac{t^{1*}}{t^{2*}} \quad \forall x_D, z_D \tag{A-3}$$

Next, the form of each boundary condition is simplified by specifying the following scalars.

$$\begin{array}{l}
S_h^{1*} = S_{hr} \\
c_{ih}^{1*} = c_{ih}^I \\
c_{ih}^{2*} = c_{ih}^J - c_{ih}^I \\
P_w^{1*} = P_{inj} \\
P_w^{2*} = P_p - P_{inj} \\
P_h^{1*} = P_{inj} \\
P_h^{2*} = P_p - P_{inj} \\
u_{wz}^{1*} = 0 \\
u_{hz}^{1*} = 0 \\
t^{1*} = 0 \\
x^{1*} = 0 \\
x^{2*} = L \\
z^{1*} = 0 \\
z^{2*} = H
\end{array} \tag{A-4}$$

Therefore, the number of unknown scalars is reduced to 10. The next step is to substitute the dimensionless variables into the governing equations. Again for brevity, only the result for the first equation is given here. That is,

$$\frac{\partial(S_{wD})}{\partial(t_D)} + \left[\frac{t^{2*} u_{wx}^{2*}}{\phi S_w^{2*} x^{2*}} \right] \frac{\partial(u_{wxD})}{\partial(x_D)} + \left[\frac{t^{2*} u_{wz}^{2*}}{\phi S_w^{2*} z^{2*}} \right] \frac{\partial(u_{wzD})}{\partial(z_D)} = 0 \quad . \quad (A-5)$$

As shown in Eq. (A-5), the scalar coefficients form dimensionless groups when one term is made dimensionless. Some of these scaling groups can be set to set to 1.0, until all scalars are determined. The remaining scaling groups form the set of unknown dimensionless groups that must be given to determine the recoveries and storage efficiencies. The final set of scaling groups used in this paper are given in Section 4.

Appendix B – Demonstration of scaling groups

This section demonstrates the idea behind the use of scaling groups, and shows an example validation of the scaling groups used in this paper. If the scaling groups were determined properly, the recoveries and storage efficiencies should be identical, or nearly so, when the same values of the scaling groups are used, independent of the parameters that go into those scaling groups. The validation is demonstrated here by comparing simulations for three different reservoirs that have the same scaling group values (see Tables B-1 and B-2). The same permeability realization is used for the three reservoirs. Figures B-1 and B-2 show that these three reservoirs given nearly exactly the same recoveries and storage efficiencies.

Table B-1: Dimensional properties of sample reservoirs S1 - S3

	S1	S2	S3
N_c	11	2	2
L (ft)	708.22	640	320
H (ft)	87.2	64	32
k_z (md)	15.16	20	20
k_x (md)	100	200	200
ρ_w (lb/ft ³)	62.4	59.95	59.95
ρ_o (lb/ft ³)	37.136	37.74	37.9
ρ_{CO2} (lb/ft ³)	44.91	44.58	44.69
k_{rw}^o	0.65	0.65	0.7
k_{ro}^o	0.58	0.58	0.59
μ_w (cp)	0.27	0.27	0.29
μ_o (cp)	0.17	0.17	0.17
μ_{CO2} (cp)	0.06	0.06	0.06
P_{inj} (psia)	4900	4900	3752.78
P_p (psia)	4422.903	4592.17	3600

Table B-2: Dimensionless group values of sample reservoirs S1 - S3

	S1	S2	S3
R_L	3.162	3.162	3.162
M_g^o	3.035	3.037	3.037
NR_g^o	0.308	0.308	0.308
S_{oiD}	0.500	0.500	0.500
M_w^o	0.709	0.708	0.709
N_o^w	4.620	4.618	4.618

S_{or}	0.300	0.300	0.300
S_{wr}	0.400	0.400	0.400
S_{wi}	0.550	0.550	0.550
V_{DP}	0.650	0.650	0.650
λ_{Dx}	1.000	1.000	1.000
λ_{Dz}	0.100	0.100	0.100

Figure B-1: Validation of dimensionless oil mass recoveries for different reservoir and fluid properties, but for the same values of the 11 dimensionless groups. The results show excellent agreement indicating that the scaling groups accurately model the process.

Figure B-2: Validation of dimensionless CO₂ storage efficiency (% MPVI) for different reservoir and fluid properties, but for the same values of the 11 dimensionless groups. Again, the results show excellent agreement indicating that the scaling groups accurately model the process.

Appendix C – Reduced response surface equations

The reduced response surface fits for R_{D1} , R_{D2} , R_{D3} , and R_{D4} that correspond to oil recovery efficiencies at 0.25, 0.75, 1.2, and 2 MPVI are

$$R_{D1} = 0.133 - 0.0266\bar{S}_{oiD} + 0.0550\bar{S}_{hr}\bar{S}_{oiD} + 0.129\bar{S}_{hr} + 0.0306\bar{S}_{hr}\bar{S}_{wr} - 0.0547\bar{S}_{hr}^2 + 0.0732\bar{S}_{wr} + 0.0209\left(\bar{M}_w^o\right)^2 + 0.0279\bar{M}_w^o + 0.0382\bar{S}_{hr}\bar{\lambda}_{Dz}, \quad (C-1)$$

$$R_{D2} = 0.500 - 0.0709\bar{R}_L + 0.0475\bar{S}_{hr} + 0.108\bar{S}_{oiD} - 0.0715\bar{M}_g^o - 0.0359\bar{R}_L\bar{\lambda}_{Dx} + 0.0470\bar{M}_w^o\bar{S}_{hr} + 0.0309\bar{M}_w^o\bar{S}_{wr} - 0.111\bar{S}_{hr}\bar{S}_{oiD} - 0.0466\bar{S}_{oiD}\bar{S}_{wr} + 0.0411\bar{R}_L^2 + 0.0522\bar{\lambda}_{Dx}^2 + 0.0445\left(\bar{M}_g^o\right)^2, \quad (C-2)$$

$$R_{D3} = 0.672 - 0.00644\bar{M}_g^o + 0.0240\bar{S}_{oiD} + 0.0608\bar{R}_L\bar{\lambda}_{Dx} - 0.0424\left(\bar{M}_g^o\right)^2 - 0.116\bar{R}_L - 0.0279\bar{R}_L^2 - 0.0430\bar{V}_{DP}\bar{M}_g^o + 0.0262\bar{\lambda}_{Dx}^2 - 0.0469\bar{S}_{hr}\bar{S}_{oiD} + 0.0417\bar{V}_{DP} + 0.0546\bar{R}_L\bar{\lambda}_{Dz} + 0.0370\bar{R}_L\bar{V}_{DP} + 0.0582\bar{S}_{hr}, \quad (C-3)$$

$$R_{D4} = 0.867 - 0.0279\bar{R}_L - 0.0535\bar{V}_{DP} + 0.0198\bar{\lambda}_{Dz} - 0.0916\bar{M}_g^o - 0.0376\bar{R}_L\bar{\lambda}_{Dx} + 0.0347\bar{R}_L\bar{\lambda}_{Dz} - 0.0319\bar{N}_o^w\bar{S}_{oiD} + 0.0293\bar{S}_{oiD}\bar{\lambda}_{Dx} + 0.0410\bar{V}_{DP}\bar{M}_g^o - 0.0260\bar{\lambda}_{Dx}\bar{M}_g^o + 0.0322\bar{R}_L^2. \quad (C-4)$$

The equation for the reduced response surface fits for the CO₂ storage at breakthrough time is

$$S_{br} = 0.561 - 0.0809\bar{R}_L + 0.0546\bar{M}_w^o - 0.103\bar{M}_g^o + 0.0438\bar{R}_L\bar{N}_o^w - 0.0437\bar{R}_L\bar{M}_g^o + 0.0651\bar{R}_L^2 + 0.0801(\bar{M}_g^o)^2. \quad (C-5)$$

The reduced response surface fits for S_{D1} , S_{D2} , S_{D3} , and S_{D4} that correspond to CO₂ storage efficiencies at 0.25, 0.75, 1.2, and 2 MPVI are

$$S_{D1} = 0.25, \quad (C-6)$$

$$S_{D2} = 0.565 - 0.0586\bar{R}_L + 0.0241\bar{M}_w^o - 0.0226\bar{V}_{DP} - 0.0705\bar{M}_g^o - 0.0232\bar{R}_L\bar{V}_{DP} - 0.0241\bar{R}_L\bar{\lambda}_{Dx} + 0.0217\bar{R}_L\bar{\lambda}_{Dz} - 0.0265\bar{R}_L\bar{M}_g^o + 0.0324\bar{R}_L^2 + 0.0230\bar{S}_{oiD}^2 + 0.0433(\bar{M}_g^o)^2, \quad (C-7)$$

$$S_{D3} = 0.670 - 0.0493\bar{R}_L + 0.0338\bar{M}_w^o - 0.0364\bar{V}_{DP} - 0.103\bar{M}_g^o - 0.0388\bar{R}_L\bar{V}_{DP} + 0.0317\bar{R}_L\bar{\lambda}_{Dz} - 0.0309\bar{R}_L\bar{M}_g^o + 0.0334\bar{R}_L^2 + 0.0586(\bar{M}_g^o)^2, \quad (C-8)$$

$$S_{D4} = 0.854 - 0.0233\bar{R}_L + 0.0306\bar{M}_w^o + 0.0262\bar{S}_{hr} - 0.0395\bar{V}_{DP} - 0.0829\bar{\lambda}_{Dz} - 0.0330\bar{M}_g^o. \quad (C-9)$$