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Influence of injection strategies on local capillary trapping during geological carbon sequestration in saline aquifers

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ABSTRACT

Local capillary trapping (LCT) of CO_2 is caused by the intrinsic heterogeneity of storage aquifers. It is computationally intensive to model LCT using conventional reservoir flow simulators. This work proposes a fast proxy method. We decouple the LCT modeling into two parts: permeability-based flow simulation using a connectivity analysis, and identification of local capillary traps (capillary entry pressure-based) using a geologic criterion. The connectivity analysis is employed to rapidly approximate CO_2 plume evolution through estimating the arrival time of CO_2. This analysis uses the geostatistical realization of permeability fields as input. The geologic criteria algorithm is used to estimate the potential local capillary traps from a given capillary entry pressure field. This field, through the Leverett j-function, is correlated to the permeability field used in the connectivity analysis. We then quantify the total volume of local capillary traps identified within the capillary entry pressure field that can be filled during CO_2 migration. We conduct several simulations in the reservoirs with different levels of heterogeneity under various injection scenarios. We demonstrate the reservoir heterogeneity affects the optimal injection rate in maximizing LCT during CO_2 injection. This work enhances our understanding of the effects of injections strategies on LCT.

1. Introduction

Geological carbon sequestration (GCS) has been widely accepted as a promising way to reduce carbon emissions and hence mitigate global warming [1]. The subsurface saline aquifers in sedimentary basins have been considered as the major storage target because of their large storage capacity and wide global distribution [1,2].

After injection into saline aquifers, CO_2 migrates upward driven by buoyancy forces [3,4]. When the buoyant CO_2 encounters a region with high capillary entry pressure within a saline aquifer, it accumulates. This kind of accumulation is termed as local capillary trapping (LCT) [5]. In this sense, LCT differs from capillary trapping because LCT results from CO_2 (non-wetting phase here) remaining *connected* as it migrates along pathways with sufficiently small entry pressure (*drainage* process), while capillary trapping is the consequence of *disconnecting* CO_2 as capillary pressure during the *imbibition* process. The differences between these two have been elaborated by Saadatpoor et al. [5] and Ren [6].

One of the main aims of GCS projects is to ensure safe and long-term CO_2 storage [1,7–9]. Since LCT is a robust trapping mechanism that minimizes the risk of leakage, it is instructive to examine how to maximize the CO_2 volume trapped by this mechanism. Several injection strategies have been proposed to enhance specific trapping mechanisms such as residual and dissolution trapping. For example, one strategy is the "inject low and let rise" approach, in which CO_2 is injected into the bottom part of an aquifer [10]. Another approach is to inject brine into the upper part of an aquifer at the same time that CO_2 is injected into the bottom [11–15]. Additionally, some work specifically focuses on increasing either residual trapping (e.g. [16,17]) or dissolution trapping (e.g. [18,19]).

Unfortunately, it is computationally intensive to model LCT in typical storage formations using full-physics reservoir simulators [5]. Resolving the discontinuity in capillary pressure and saturation that arises between grid blocks with different capillary pressure-saturation curves introduces a convergence problem in numerical simulation, which requires the use of very small time-steps. Alternatively, upscaling techniques could be used to assess the effect of capillary heterogeneity on CO_2 travel time, equivalently trapped saturation, and equivalent leakage flux [20–22]. However, these upscaling procedures always smear the spatial distribution of LCT. Such smearing might cause non-negligible errors in quantifying the amount of safely stored CO_2 since LCT is characterized by large-saturations of CO_2. Development of

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Nomenclature

Roman Symbols

A	Contact area of the adjacent grid blocks, cm^2
C_t	Reservoir total compressibility, 1/atm
$ED1$	Original edge weight, []
$ED2$	New edge weight, sec
g	Gravity acceleration, 9.8 m/s^2
H_{re}	Reservoir thickness, cm
h	Height of CO_2 column, cm
$J_{(S_w)}$	Leverett j-function, []
k	Permeability, Darcy
k_v	Mean of vertical permeability, Darcy
$\overline{k}$	Geometric average of permeability, Darcy
k_i	Permeability of the grid i, Darcy
k_j	Permeability of the grid j, Darcy
k_{rg}	Relative permeability of CO_2, []
$\overline{k_g}$	Average relative permeability of CO_2, []
k_{50}	50 percentile permeability value, Darcy
$k_{84.1}$	84.1 percentile permeability value, Darcy
L	Length of grid block, cm
L_{pr}	Reservoir perforation length, cm
p_c^{entry}	Capillary entry pressure, psi
Q	Well injection rate, cm^3/s
q_g	CO_2 flow rate, cm^3/s
r_1	The radial distance of grid i from a wellbore, cm
r_2	The radial distance of grid j from a wellbore, cm
$\overline{S_g}$	Specific saturation at which a given grid is filled, []
T	Transmissivity between the adjacent grid blocks, cm^3
t	CO_2 injection duration, sec
u	Total or Darcy velocity of CO_2, ft/day
V_{dp}	Dykstra-Parsons variation coefficient, []
V_{pi}	Pore volume of grid i, cm^3
V_{pj}	Pore volume of grid j, cm^3

Greek Symbols

μ_g	Viscosity of gas (CO2), cp
μ_w	Viscosity of brine, cp
ρ_g	Density of CO_2, kg/m^3
σ	Interfacial tension between CO_2 and brine, N/m
θ	Contact angle, degree
ϕ	Porosity, []
ϕ_i	Porosity of grid i, []
ϕ_j	Porosity of grid j, []
ΔP	Viscous pressure difference, atm
$\Delta\rho$	Density difference between brine and CO_2, kg/m^3

Acronyms

CA	Connectivity analysis
CCEP	Critical capillary entry pressure
CMG	Computer modeling group
GCS	Geological carbon sequestration
LCT	Local capillary trapping
RC	Reservoir condition
SC	Surface condition

inexpensive methods to model the spatial distribution of LCT is imperative for the future monitoring, verification, and accounting strategies for carbon sequestration.

This work sets out to develop an integrated methodology to rapidly evaluate the impact of injection strategies on *dynamic* LCT (the volume of CO_2 trapped in LCT during injection). In our companion paper [23], we employed a geologic-criterion-algorithm to study local capillary traps for specific geologic models. This algorithm however does not account for CO_2 flow dynamics, thus these identified traps are *static*. To evaluate *dynamic* LCT, we add multiphase dynamics into our previous geologic-criterion-algorithm. The connectivity analysis [24], originally developed for characterizing well-to-reservoir connectivity, is adapted here to analyze CO_2/water immiscible flow. In this analysis, an edge weight is used to describe the connectivity between neighboring grid blocks. This weight accounts for the multiphase flow properties, injection rates, and buoyancy effects. We integrate the two methods to quantify the volume of local capillary traps that can be filled during CO_2 injection. These filled local capillary traps become LCT. We explore various injection scenarios in storage formations with different levels of heterogeneity. To the authors' best knowledge, this is the first study in the literature that examines the effects of injection strategies on LCT. The understanding obtained here will assist GCS operators to maximize LCT in storage aquifers.

2. Theory and approach

2.1. Using a connectivity analysis (CA) to approximate CO_2 plume

2.1.1. Connectivity and edge weight

According to Hirsch and Schuette [25], a reservoir geologic model can be considered as a graph, and a grid block in the geologic model is equivalent to a node in the graph. Adjacent nodes are connected with edges that are weighted by reservoir parameters such as porosity and permeability. The physical meaning of the edge weight is the time needed to fill a given pore volume with a fluid of unit viscosity under a unit pressure gradient. Its original definition is for modeling single-phase flow [25].

Jeong [26] extended the edge weight for modeling two-phase immiscible flow by incorporating the buoyancy effect, relative permeability, and viscous pressure. A new definition was derived based on the Darcy's law. The subscript 'g' represents CO_2.

$$q_g = \frac{k k_{rg} A(\Delta P + \rho_g g h)}{\mu_g L} \tag{1}$$

If the transmissivity (T) between cells is defined as Eq. (2), we can write Eq. (1) into Eq. (3).

$$T = k\frac{A}{L} \tag{2}$$

$$q_g = \frac{T k_{rg}(\Delta P + \rho_g g h)}{\mu_g} \tag{3}$$

Eq. (4) shows the original definition of edge weight for single-phase flow. In two-phase flow, a given cell is assumed to be filled by CO_2 to an average saturation ($\overline{S_g}$ in Eq. (5)). It is equal to the average gas saturation before breakthrough in 1D immiscible displacement, as determined from a fractional flow curve [27]. Then, the edge weight for two-phase flow can be written as Eq. (5)

$$ED1 = \frac{\sqrt{Vp_i * Vp_j}}{T_{ij}} \tag{4}$$

$$ED2 = \frac{\sqrt{Vp_i * Vp_j} * \overline{S_g}}{q_g} \tag{5}$$

Substituting Eq. (3) into Eq. (5), we can derive the final form of edge