Assessment of CO$_2$ storage potential in naturally fractured reservoirs with dual-porosity models

Rafael March$^1$, Florian Doster$^1$, Sebastian Geiger$^1$

$^1$Institute of Petroleum Engineering, Heriot-Watt University, Edinburgh Campus, EH14-4AS, United Kingdom.

Key Points:

• We develop an estimate for brine drainage timescales by supercritical CO$_2$ during carbon storage in fractured formations.
• We develop a new transfer function based on this timescale estimate that improves existing transfer functions for dual-porosity models.
• We illustrate with simulations of injection scenarios into a fractured anticline that carbon storage in a naturally fractured reservoir is possible.

Corresponding author: F. Doster, f.doster@hw.ac.uk
Abstract
Naturally Fractured Reservoirs (NFR’s) have received little attention as potential CO\textsubscript{2} storage sites. Two main facts deter from storage projects in fractured reservoirs: 1) CO\textsubscript{2} tends to be non-wetting in target formations and capillary forces will keep CO\textsubscript{2} in the fractures, which typically have low pore volume; and 2) The high conductivity of the fractures may lead to increased spatial spreading of the CO\textsubscript{2} plume. Numerical simulations are a powerful tool to understand the physics behind brine-CO\textsubscript{2} flow in NFR’s. Dual-porosity models are typically used to simulate multiphase flow in fractured formations. However, existing dual-porosity models are based on crude approximations of the matrix-fracture fluid transfer processes and often fail to capture the dynamics of fluid exchange accurately. Therefore, more accurate transfer functions are needed in order to evaluate the CO\textsubscript{2} transfer to the matrix. This work presents an assessment of CO\textsubscript{2} storage potential in NFR’s using dual-porosity models. We investigate the impact of a system of fractures on storage in a saline aquifer, by analyzing the timescales of brine drainage by CO\textsubscript{2} in the matrix blocks and the maximum CO\textsubscript{2} that can be stored in the rock matrix. A new model to estimate drainage timescales is developed and used in a transfer function for dual-porosity simulations. We then analyze how injection rates should be limited in order to avoid early spill of CO\textsubscript{2} (lost control of the plume) on a conceptual anticline model. Numerical simulations on the anticline show that naturally fractured reservoirs may be used to store CO\textsubscript{2}.

1 Introduction

There is a growing concern about the rising levels of anthropogenic CO\textsubscript{2} in the atmosphere, as they are one of the major contributors to the greenhouse effect. During the past two decades, the identification and development of reliable and effective techniques to mitigate the environmental effects of the greenhouse gases have been a focus of the scientific research community. These techniques include Carbon Capture and Utilization (CCU), Negative Emission Technology (NET) and Carbon Capture and Storage (CCS) [IPCC, 2005; Cuellar-Franca and Azapagic, 2015; Ringrose, 2017].

In particular, geological storage of CO\textsubscript{2} is regarded as an important technique to achieve the targets of temperature increase established in the last decade and updated during the Paris climate agreement negotiated in December 2015. Pacala and Socolow [2004] argued that a mix of different technologies, including CCS, will have to be em-
ployed in order to solve the climate problem for the next five decades. They estimated that 3500 projects of the size of the Sleipner CCS project in the North Sea would be required to solve one seventh of the global temperature increase problem. Celia et al. [2015] later updated these numbers, using present-day data, and calculated that this number of projects would solve just one tenth of it. Therefore, the number of CCS projects needs to increase considerably to have a noticeable impact on the environment. At this scale, the availability of geological formations suitable for CO$_2$ injection at locations that allow economic operations is a limiting factor that hinders the global implementation of carbon storage.

Fractured reservoirs are ubiquitous in sedimentary basins across the world. Estimates suggest that more than half of the world’s remaining conventional hydrocarbon resources are stored in extensively fractured carbonate reservoirs [Burchette, 2012]. However, these reservoirs have received little attention as potential candidates for CO$_2$ storage. Yet, they offer a significant potential for combining CO$_2$ storage with enhanced oil recovery [Agada et al., 2016]. The primary reason seems to be related to the fact that for most formations, CO$_2$ is the non-wetting phase relative to the resident fluid. Since capillary pressure in the fractures is typically orders of magnitude lower than in the rock matrix, capillary forces may prevent CO$_2$ from invading the rock matrix. This could severely impact the storage potential of the aquifer, as the matrix generally accounts for most of the pore volume. This negative effect may be specially evident in aquifers with small thickness (< 50 m) or with a set of near-horizontal fractures with apertures that are large enough to prevent the creation of capillary bridges across the vertical section. Fractures also have high conductivity and the presence of an interconnected system of fractures may lead to fast flow of CO$_2$ through the fracture system, without significant storage in the rock matrix. This could lead to a loss in control of the CO$_2$ plume, and potentially to CO$_2$ leakage through abandoned wells or reactivated faults. Despite these challenges, the study of CO$_2$ storage in fractured formations is very relevant to the global implementation of CCS. Since fractures are a major source of uncertainty in geological formations, the existence of a previously unidentified fracture system should be incorporated in the risk analysis of storage projects. Moreover, as fractured reservoirs are numerous, they may be considered as storage site as the number of CCS projects increases. The ability to model and simulate the multi-phase dynamics in such formations is of utmost importance to the development of a storage project.
Techniques to simulate flow in fractured porous rocks are typically separated in two large families of methods. The first family include methodologies that explicitly represent the fractures as geometrical features in the simulation model. Pertaining to this family are the Discrete Fracture and Matrix (DFM) methods, e.g. [Karimi-Fard et al., 2004; Moinfar et al., 2013; Geiger et al., 2009; Schmid et al., 2013], and the Embedded Discrete Fracture Model (EDFM), e.g. [Shah et al., 2016; Fumagalli et al., 2016; Moinfar et al., 2014]. One limitation of this family of methods is that they do not generally allow the representation of all fractures at the reservoir scale due to computational complexities. The second family includes methods that consider the fractures as a second continuum. Of particular importance in such class of methods are the Dual Porosity [Warren and Root, 1963; Kazemi et al., 1976], the Dual-Porosity Dual-Permeability [Kazemi et al., 1976], together with their extensions like the Multiple Interacting Continua [Pruess, 1985] and the Multi-Rate Dual-Porosity methods [Tecklenburg et al., 2016; Di Donato et al., 2007; Geiger et al., 2013; Maier and Geiger, 2013]. Multiple-continuum methods are popular in the reservoir simulation community due to their computational efficiency, as they are based on the upscaling of the fracture system properties instead of representing each individual fracture. A key element of these upscaled methods are mass transfer functions that model the fluid exchange between fractures and matrix. The modelling of multi-phase fluid transfer between both continua is a challenging task that has been addressed extensively, but is not fully solved; we refer to Lemonnier and Bourbiaux [2010a], Abushaikha and Gosselin [2008], Al-Kobaisi et al. [2009] and Ramirez et al. [2009] for comprehensive reviews. While the understanding of multi-phase dynamics in porous media has been advanced throughout the years, the first transfer functions developed by Kazemi et al. [1976] remain popular due to their simplicity and ability to address different physical mechanisms. Several modifications of these functions were suggested (e.g. Al-Kobaisi et al. [2009]). However, none of them focus on CO$_2$-brine systems. The development of a transfer function that captures the drainage of brine by supercritical CO$_2$ requires an estimate of the timescale of the drainage process.

In this manuscript, we hence develop an estimate of the order of magnitude of the timescale of CO$_2$-induced matrix block drainage, by extending the work of Di Donato et al. [2006]. This timescale consists of a model to estimate the time it takes to saturate a matrix block to equilibrium, and hence is an important component to understand the dynamics of CO$_2$ storage in NFRs. Moreover, it leads to a transfer function that accu-
rately models gravity-drainage processes in the context of CO$_2$ storage. The application
of this transfer function in the dual-porosity framework allows us to have a conceptual
understanding of the impact of fractures during CO$_2$ storage operations.

This paper is structured as follows. In section 2, we provide a general overview of
the dynamics of CO$_2$ in naturally fractured reservoirs and present the governing equa-
tions as well as simplifying assumptions for single- and dual-porosity porous media. Sec-
tion 3 comprises the main part of this work. It presents an analysis of storage capacity
and drainage timescales for a single matrix block via numerical simulation of fully-resolved
matrix blocks. It then provides a novel model to estimate the timescale of matrix block
drainage and a new transfer function based on this timescale estimate. This model en-
ables CCS simulations with dual-porosity models. Finally, at the end of this section, the
performance of this transfer function is compared with the ones given by other trans-
fer functions that are popular in commercial and open-source simulators. In section 4,
we consider a conceptual anticline geometry to evaluate the impact of fractures on field-
scale storage using dual-porosity simulations. We also suggest a model that is based on
the timescale estimate developed in section 3 and that limits the injection rate to avoid
the early spill of CO$_2$. Finally, in section 5, we provide a summary of the main results
and contributions of this work, together with some general guidelines regarding CO$_2$ stor-
age operations in NFRs.

2 CO$_2$ storage dynamics in NFR’s

We start the discussion by reviewing the main physical mechanisms that take place
during CO$_2$ injection in fractured formations. We focus our discussion on fractured saline
aquifers, because saline aquifers have the largest storage potential [IPCC, 2005]. CO$_2$
storage operations target geological formations whose temperature and pressure condi-
tions are such that CO$_2$ is in supercritical state. In this state, the gas density increases
significantly, which improves its stored mass per unit pore volume. Typical values for
CO$_2$ density range from 266 to 733 kg/m$^3$, depending on the pressure and temperature
conditions of the formation. The compressibility, on the other hand, ranges typically from
$10^{-9}$ to $10^{-8}$ Pa$^{-1}$, which is at least one order of magnitude lower than that of a gas [Law
and Bachu, 1996]. Brine density is more sensitive to the salinity of the water, with val-
ues ranging from 945 to 1230 kg/m$^3$ [Nordbotten and Celia, 2012]; its compressibility is
of the order of $10^{-10}$ Pa$^{-1}$. The density of brine is therefore always larger than the den-
sity of CO₂, and this density difference induces upward flow of CO₂. Therefore, suitable
geological formations for storage should be overlaid by a capping formation that prevents
CO₂ from rising to the surface. CO₂ will also dissolve in the resident brine, with typ-
ical values of solubility by mass ranging from 1% to 6% [Spycher et al., 2003]. The dis-
solution of CO₂ leads to an increase in the density of brine, which may create an unstab-
le system and therefore the generation of convective dissolution cells. The convective
dissolution of CO₂ in brine has been identified as an important mechanism for safe stor-
age of CO₂ in unfractured saline aquifers [Emami-Meybodi and Hassanzadeh, 2015; Suekane
et al., 2008; Macminn et al., 2011; Riaz et al., 2006]. Therefore, the injection of CO₂ in
a saline aquifer gives rise to a multi-phase multi-component system, with distinct timescales
associated with buoyancy, injection and mass transfer between the phases.

Modelling of fractured formations is a challenging task as the fractures introduce
additional timescales to the system. An inter-connected system of fractures can act as
a high-permeability pathway that enables rapid fluid flow. Hence, injected CO₂ can quickly
travel through the fracture system, while its transfer to the rock matrix will occur at an
usually slower timescale (Figure 1(a)). Fracture-matrix transfer mechanisms were exten-
sively studied through laboratory and numerical experiments (e.g., Lemonnier and Bour-
biaux [2010b]; Fernø et al. [2013]; La et al. [2008]; Ahmed Elfeel et al. [2016]). Figure
1(b) summarizes the most relevant transfer mechanisms. If the permeabilities of frac-
ture and matrix are comparable or if there is capillary continuity between the matrix blocks,
CO₂ may enter the rock matrix blocks by viscous displacement. Otherwise, fractures will
quickly transport the CO₂ phase, creating isolated systems of brine-saturated matrix blocks
surrounded by CO₂ saturated fractures. Each matrix block is not in equilibrium in this
configuration, as brine is heavier than CO₂ and will redistribute with the supercritical
fluid, during a drainage process caused by the contrast between capillary and gravity forces
(mechanism named “buoyancy redistribution” in Figure 1(b)). When the injection rate
is reduced or injection stops, fractures otherwise saturated by CO₂ may be filled by wa-
ter. Capillary forces then cause the wetting phase to imbibe the rock matrix, displac-
ing CO₂ back to the fractures [March et al., 2016] (mechanism named “capillary imbi-
bition” in Figure 1(b)). This process may lead to trapping of CO₂ phase in the pores
of the rock due to the hysteretic nature of the relative permeability [Juanes et al., 2006].

We believe these two mechanisms - gravity drainage during CO₂ injection phase
followed by capillary imbibition during plume migration when injection stops - are the
main mechanisms responsible for fluid transfer between fractures and matrix during CO$_2$
storage operations in NFRs. Other mechanisms like viscous transfer, fluid compression
and dissolution are unlikely to contribute to the transfer of CO$_2$ to the matrix during
the injection phase. Viscous transfer may be relevant in the near-well region, where large
pressure gradients induced by the well may generate a horizontal component inside the
matrix blocks. However, since we consider NFRs with an interconnected system of frac-
tures and good permeability contrast between fracture and matrix, far from the near-
well region pressure gradients experienced by the formation will generally lead to a fast
flow of CO$_2$ in the fractures, with a negligible amount of CO$_2$ invading the matrix due
to viscous displacement. CO$_2$ dissolution in brine happens at timescales of hundreds of
years, much slower than the typical timescales of CO$_2$ injection considered here. Convection-
driven dissolution (“density fingers”) is regarded as a key physical mechanism to shorten
this timescale [Riaz et al., 2006]. The high-permeability fractures, however, represent a
preferential pathway for the development of convection cells. This hinders the develop-
ment of convection cells within the matrix blocks. Finally, the fact that the brine that
is initially resident in the matrix blocks has very low compressibility allows us to neglect
the transfer due to brine compression during CO$_2$ injection. A quick and conservative
estimate allows us to estimate the timescale of pressure equilibration inside a matrix block.
Considering a permeability of $k_m = 1$ mD, a porosity of $\phi_m = 0.1$, a brine compress-
ibility of $c = 10^{-10}$ Pa$^{-1}$, a viscosity of $\mu_w = 1$ cP and a characteristic block dimen-
sion of $L = 100$ m, the pressure diffusion timescale is estimated by $T \approx L^2/\eta$, with
$\eta = k_m/\phi_m \mu_w c$. This yields an equilibration time of $\approx 1$ day. The equilibration time
can be considered instantaneous when compared to the operation’s timescale, which is
in the order of years.

An ideal CO$_2$ operation in an NFR maximizes the amount of CO$_2$ in the rock ma-
trix. In other words, it is undesirable that CO$_2$ remains in the fractures, as the CO$_2$ plume
may quickly flow through the fractures and reach a leakage pathway through the cap rock
or an abandoned well. Therefore, the development of a model that describes the timescale
of CO$_2$ transfer due to gravity drainage (commonly denoted a transfer function in the
dual-porosity modeling framework) is important to design efficient storage operations.
In the next subsections we analyze the timescales and stored amount of CO$_2$ in a ma-
trix block from numerical simulations and develop a timescale estimate for brine drainage
by supercritical CO$_2$. 

-7-
2.1 Governing equations

We now introduce the system of conservation equations for the wetting (brine) and non-wetting phases (CO$_2$), that together with the multi-phase extension for Darcy’s law and appropriate boundary conditions form a closed set of partial differential equations that describe the flow of compressible immiscible fluids in porous media [Bear, 1972]:

$$\frac{\partial (\phi\rho_\alpha S_\alpha)}{\partial t} + \nabla \cdot (\rho_\alpha q_\alpha) = \tilde{q}_\alpha,$$

$$q_\alpha = -k\lambda_\alpha (\nabla p_\alpha - \rho_\alpha g),$$

where $S_\alpha$ is the saturation of phase $\alpha$, $\rho_\alpha$ its density, $\tilde{q}_\alpha$ mass source terms (e.g. due to wells) and $\phi$ and $k$ the porosity and permeability of the porous medium. The multiphase Darcy model relates the Darcy velocity $q_\alpha$ of phase $\alpha$ with the gradient of the phase’s pressure $p_\alpha$ and its mobility, defined as $\lambda_\alpha = k_{r\alpha}/\mu_\alpha$, where $\mu_\alpha$ is its viscosity and $k_{r\alpha}$ is the relative permeability to phase $\alpha$. Phase pressures are related by the capillary pressure through the expression $p_\alpha = p_w + p_c(S_w)$. For simplicity, in the remainder of this text, we assume Corey-type relationships for the relative permeability and capillary pressure. Therefore, we write $k_{r\alpha} = k_{r\alpha}^{max} S_{\alpha e}$ and $p_c(S_w) = P_e S_{we}^{-n_p}$, where $S_{\alpha e}$ is the effective saturation, normalized by the residual saturations, and $n_\alpha$ and $n_p$ are the power-law exponents of the relative permeabilities and capillary pressure. We disregard geomechanical effects here, noting that the main mechanical effects of CO$_2$ injection in fractures (increased fracture transmissivity due to fracture opening) and matrix (potential block shrinkage due to rock compression, leading to brine transfer to matrix) are unlikely to change significantly the results shown in this work.

For incompressible fluids and solids, the conservation equations defined in Equation (1) are identically represented by a single equation for the saturation of the wetting phase and an equation for the total flux $q_t \equiv q_w + q_n$:

$$\nabla \cdot q_t = \tilde{q}_w/\rho_w + \tilde{q}_n/\rho_n,$$

$$\phi \frac{\partial S_w}{\partial t} + \nabla \cdot q_w = \tilde{q}_w/\rho_w,$$

$$q_w = f_w q_t + k f_w \lambda_n \frac{dp}{dS_b} \nabla S_b + (\rho_w - \rho_n) g \nabla z,$$

where $f_\alpha = \lambda_\alpha/\lambda_t$, and $\lambda_t = \lambda_w + \lambda_n$ is the fractional flow of phase $\alpha$. In this work, CO$_2$ and brine are assumed to be incompressible due to the low compressibility of brine and CO$_2$ in supercritical state. The average densities of the fluids are defined by the depth and temperature conditions of the target storage formation.
2.2 Dual-porosity formulation

The direct utilization of Equations (1) or (2) to simulate the flow in NFR’s is prohibitively expensive for most of the realistic geological models; this would require the explicit representation of each fracture by either conforming the simulation grid to them (e.g. [Karimi-Fard et al., 2004]) or by embedding them in the computational mesh (e.g. [Fumagalli et al., 2016]). Dual-continuum approaches [Warren and Root, 1963; Kazemi et al., 1976], on the other hand, have been widely used in the past decades since they do not require explicit fracture representation in the computational model. Instead, the fracture system is represented as a second continuum that is superposed to the rock matrix. The two continua are related by an upscaled transfer term $T$ that models the mass transfer between the two continua. Equations (1) are extended by a set of conservation equations for the rock matrix. We then write:

$$\frac{\partial}{\partial t} \left( \phi_f \rho_w S_{wf} \right) + \nabla \cdot (\rho_w q_{wf}) = \tilde{q}_w - T_w,$$

$$\frac{\partial}{\partial t} \left( \phi_f \rho_n S_{nf} \right) + \nabla \cdot (\rho_n q_{nf}) = \tilde{q}_n - T_n,$$

$$(3)$$

$$\frac{\partial}{\partial t} \left( \phi_m \rho_w S_{wm} \right) = T_w,$$

$$\frac{\partial}{\partial t} \left( \phi_m \rho_n S_{nm} \right) = T_n,$$

where the subscripts $\{f, m\}$ identify variables of the fracture and matrix continuum. The transfer rate term $T_\alpha$ models the rate of mass exchange of phase $\alpha$ between fracture and matrix per unit bulk volume. The transfer rate is a key ingredient of dual-porosity models, and although several expressions for this term exist in the literature, the development of a model that accurately capture the transfer mechanisms shown in Figure 1 is challenging and still an open topic of research. In particular, as shown in the next sections, current formulations of transfer functions fail to predict the drainage dynamics accurately. Therefore, the utilization of the dual-porosity model to evaluate CO$_2$ storage in NFRs requires a new model to capture gravity drainage.

We consider the dual-porosity model defined by Equations (3) in this work to evaluate geological storage of CO$_2$ in NFRs. Dual-porosity models are applicable to naturally fractured reservoirs with a well-connected system of fractures and high permeability contrast between both media [Bourbiaux et al., 2002]. We limit our analysis to such reservoirs. One of the key contributions of this work is the development of an estimate for the timescale of CO$_2$ transfer from the fractures to the matrix blocks. This timescale
provides an expression for the transfer terms $T_{\alpha}$ that captures the drainage of brine by CO$_2$ on a block scale with reasonable accuracy.

3 Capacity and drainage timescales for a single matrix block

In section 2 we discussed that the fast flow of CO$_2$ in the fractures creates isolated systems of brine-saturated blocks. These blocks are drained by CO$_2$ if buoyancy is large enough to overcome the capillary entry pressure. There are two important aspects to be analyzed in this transfer process. The first is the maximum amount of CO$_2$ that can be stored in a matrix block that is surrounded by fractures saturated by CO$_2$. The maximum CO$_2$ volume gives a measure of the negative impact of fractures on CO$_2$ storage. The second is the time it takes for a matrix block that is being drained to reach equilibrium with the CO$_2$-saturated fractures. The drainage time provides a timescale for the CO$_2$ transfer to the matrix, and is important since a slow transfer process means that the CO$_2$ plume spreads farther in the fracture system and the potential for leakage is increased. In this section we analyze the results of fully-resolved numerical simulations of CO$_2$-brine drainage on three-dimensional matrix blocks.

3.1 Setup for a single matrix block

In order to understand the dynamics of drainage at the scale of a matrix block, a series of simulations were run using MRST [Lie et al., 2011] to evaluate the amount of CO$_2$ stored in a block and the drainage timescale on a diverse number of CO$_2$ storage environments. A summary of the rock and fluid properties considered is provided in Table 1. As the drainage dynamics depend on the dimensions and aspect ratio of the matrix blocks, we consider two representative block geometries: a cubic block ($L_x = L_y = L_z = 10$ m) and a tall block, with the vertical length much larger than the horizontal dimensions ($L_x = L_y = 1$ m and $L_z = 20$ m) (see Figure 2). The cubic block represents a matrix block in a reservoir that has three perpendicular sets of fractures with sufficient aperture to prevent the formation of capillary bridges. Labastie [1990] has measured in experiments that - for a surface tension of 24 mN/m - apertures greater than 0.3 mm do not allow for the creation of capillary bridges. Therefore, the cubic block has all its faces open for flow, representing the typical “sugar cube” geometry [Warren and Root, 1963]. The tall block has only the lateral faces open for flow (no-flow boundary conditions at top and bottom faces), representing a reservoir with no horizontal fractures,
or with strong capillary continuity across the vertical blocks (sometimes referred to as “match stick” geometries). Blocks with similar aspect ratio are seen in fractured outcrops [Egya et al., 2018] and in the In Salah CO₂ storage project [Iding and Ringrose, 2010; Eiken et al., 2011]. Note, that we do not consider cases where the horizontal fracture spacing is much larger than the reservoir thickness. Fractures are modeled as boundary conditions on the matrix blocks. Fractures usually have very high permeability, and therefore injected CO₂ should quickly segregate in the fracture system and reach hydrostatic equilibrium [Guo et al., 2014]. Hence, in both models, the open faces are prescribed with hydrostatic CO₂ pressure. The model was discretized with uniform grid cells of \( \Delta x = \Delta y = \Delta z = 10 \) cm. A constant time step of \( \Delta t = 0.1 \) day was considered for all simulations. This discretization was shown to be sufficient to capture the dynamics for all the simulation cases.

To cover representative scenarios for CO₂ storage, we consider four different storage environments, representing formations at shallow and deep depths in warm or cold basins [Nordbotten and Celia, 2012]. These cases are named shallow-cold, deep-cold, shallow-warm and deep-warm. “Shallow” formations are located at 1-km depth, while “deep” formations at 3-km depth. “Cold” basins have a surface temperature of 10 °C and geothermal gradient of 25 °C/km, while “warm” basins have a surface temperature of 20°C and geothermal gradient of 45°C/km. We consider low-salinity brines. The corresponding densities and viscosities of the fluids for each of the four environments, from Nordbotten and Celia [2012], are given in Table 1. Representative values for porosity, residual brine saturation, absolute and relative permeability parameters are taken from five samples (two sandstones and three carbonates) from Bennion and Bachu [2008]. We keep their sample names and refer to them as viking#2, cardium#2, wabamun#2, nisku#1 and cooking-lake. The parameters are given in Table 1. Since there is no capillary pressure data available for the five selected samples, we consider two capillary pressure levels, a “low-\( P_c \)” and a “high-\( P_c \)” case (see Table 1). Capillary pressure depends on a series of parameters that are generally uncertain and difficult to measure in-situ, such as surface tension and contact angle between the phases, and therefore we have decided to change this parameter to cover these two possible scenarios. In the remainder of this text, each simulation case will be labeled as \{sample\}-\{environment\}-\{pc level\} (e.g. cardium#2-deep-cold-low-\( P_c \)). A total of 2 shapes \( \times 4 \) environments \( \times 5 \) samples \( \times 2 \) \( P_c \) levels = 80 simulations were considered in this analysis.
3.2 Capacity and drainage timescales from numerical simulations

In this section, we discuss the results of the numerical simulations by analyzing the maximum volume of CO\textsubscript{2} that invaded the block when the fluids reach an equilibrium, denoted as \(V_{\text{CO}_2}^{\text{max}}\), the maximum mass of CO\textsubscript{2} in the block at this point, denoted as \(M_{\text{CO}_2}^{\text{max}}\), and the time it takes to reach equilibrium, denoted as \(t_{95}\). We take \(t_{95}\) from the numerical simulations as the time when the volume of CO\textsubscript{2} inside the block corresponds to 95\% of \(V_{\text{CO}_2}^{\text{max}}\). As the lateral faces are open for flow and at hydrostatic pressure of CO\textsubscript{2}, in equilibrium the phase pressures are hydrostatic and their difference is compensated by capillary pressure. The final saturation profile is calculated analytically by evaluating the inverse of the capillary pressure at the difference between hydrostatic pressures for each depth: \(S_n^\infty(z) = 1 - p_c^{-1}(\Delta \rho g (L_z - z))\), where \(\Delta \rho = \rho_w - \rho_n\) and the \(z\) axis denotes depth. This gives a maximum volume of \(V_{\text{CO}_2}^{\text{max}} = \phi_m L_x L_y \int_{z=0}^{z=L_z} S_n^\infty(z) \, dz\). The maximum volume is calculated analytically based on the rock and fluid properties for each simulation case. The maximum mass is calculated by multiplying the maximum volume by the density of CO\textsubscript{2}, \(M_{\text{CO}_2}^{\text{max}} = \rho_{\text{CO}_2} V_{\text{CO}_2}^{\text{max}}\). We also define the pore volume that is effectively used for storage, \(V_{\text{CO}_2}^\% = V_{\text{CO}_2}^{\text{max}}/(\phi_m (1 - S_{wr}) V_b)\), where \(V_b\) is the volume of the block. This parameter allows us to evaluate the storage loss due to the presence of fractures.

Figure 3 shows the results of the numerical simulations for the sugar cube block. We restrict the analysis in this section to this block shape, noting that it also applies for the match stick geometry. The circles are inversely scaled according to the capillary pressure level (small circles correspond to high-\(P_c\) and large circles correspond to low-\(P_c\)). The circle fill colors correspond to different environments (shown in the legend of the picture), while the color of the edges correspond to different samples (shown in the picture).

The drainage time, \(t_{95}\), shows a large variation across the different cases, ranging from \(t \approx 10\) days to \(t \approx 355\) days. It is therefore an important metric to be observed during storage operations. In the low-\(P_c\) cases, the largest drainage times are seen in the viking#2 and nisku#1 samples, due to their larger effective pore volume and lower permeability. The shallow-cold environment leads to higher times compared to the deep-cold, which is more evident for the nisku#1 sample (\(t \approx 355\) days vs. \(t \approx 150\) days). This is due to the larger viscosity ratio between CO\textsubscript{2} and brine in deep-cold compared to shallow-cold environments (\(\mu_n/\mu_w \approx 0.157\) vs. \(\mu_n/\mu_w \approx 0.06\)). The deep-warm environment shows the largest value of viscosity ratio, which explains why the yellow cir-
cles are concentrated on the left half of the plot ($\mu_n/\mu_w \approx 0.2$). The wabamum#2 sample has similar properties to that of the cooking-lake. Hence, they show similar maximum masses and drainage times for each environment in the low-$P_c$ cases. However, a high contrast in $t_{95}$ is seen between these samples for the deep-warm, high-$P_c$ cases ($t_{95} \approx 11$ days vs. $t_{95} \approx 133$ days). The unfavourable conditions seen in the cooking-lake sample are due to very high Corey exponent for the CO$_2$ relative permeability ($n_n = 5.6$), that slows down drainage. This effect is less evident when buoyancy forces are very strong.

In fact, in hydrocarbon recovery operations, the assumption of $\mu_w \gg \mu_n$ usually leads to an equation for the non-wetting phase invasion that completely disregards the influence of the non-wetting phase [Hagoort, 1980]. That is, if buoyancy is high enough and the viscosity of the wetting phase is much larger than the viscosity of the non-wetting phase, the wetting phase dominates the flow and the non-wetting phase only occupies the void space without creating any resistance to flow. However, this is not always the case in CO$_2$ storage operations. In supercritical state, CO$_2$ has its viscosity increased, decreasing the viscosity contrast between CO$_2$ and brine. This is reflected in the high drainage times seen in the cooking-lake-high-$P_c$ case due to high $n_n$.

While $M_{CO_2}^{max}$ changes for each sample due to different porosities and $S_{wr}$, $V_{CO_2}^{\%}$ changes only with the environment and the capillary pressure level, as this parameter is normalized by the effective pore volume for each case. One of the key parameters to understand the behavior of the block stored mass and volume is the density difference between brine and CO$_2$. It determines the maximum penetration depth of the CO$_2$ front. The shallow-warm environment has a higher $\Delta \rho$ ($\Delta \rho = 732$ kg/m$^3$), while the deep-cold has a lower $\Delta \rho$ ($\Delta \rho = 222$ kg/m$^3$). Therefore, the shallow-cold and deep-cold environments show different values for the CO$_2$ storage volume: $V_{CO_2}^{\%} \approx 85\%$ and $V_{CO_2}^{\%} \approx 60\%$, respectively, for the low-$P_c$ case (Figure 3(b)). On the other hand, cold basins lead to the highest values of CO$_2$ density, as $\rho_{CO_2}$ increases with decreasing temperature ($\rho_n = 714$ kg/m$^3$ and $\rho_n = 733$ kg/m$^3$ for shallow-cold and deep-cold environments). Hence, more CO$_2$ is stored. This explains the behaviour of the shallow-cold and deep-cold environments in the upper part of Figure 3(a). In short, high $\rho_{CO_2}$ implies low $\Delta \rho$ and therefore low $V_{CO_2}^{\%}$, but also implies high $M_{CO_2}^{max}$. This is an interesting competing behavior of the CO$_2$ density that is only seen in fractured formations.

In summary, this section analyzed the behavior of three important parameters to be regarded in CO$_2$ storage operations in NFR’s: $V_{CO_2}^{\%}$, $M_{CO_2}^{max}$ and $t_{95}$. While the first
two parameters are easily calculated using the rock and fluids properties, the drainage timescales were post-processed from the numerical simulations. Since running fully-resolved block simulations may be prohibitive for real formations, the development of an analytical estimate for $t_{d5}$, the drainage timescale, is an important contribution of this work and is shown in the next sections.

3.3 Estimation of drainage timescale from fractional flow

In this section, we investigate the saturation equation for incompressible two-phase flow (Equation (2)) to develop a timescale estimate for the drainage process. We consider that drainage occurs essentially as a vertical downwards displacement, as observed in experiments described by Pedrera et al. [2002] and Hagoort [1980], and later used by Di Donato et al. [2006] and March et al. [2017] to develop transfer functions for gravity drainage. Therefore, we rewrite Equation (2) below assuming one-dimensional downwards displacement of the non-wetting phase and omitting the source terms:

$$\phi_m \frac{\partial S_w}{\partial t} = - \frac{\partial}{\partial z} \left( f_w q_t + k_{fw} \lambda_n \frac{dP_c}{dS_w} \frac{\partial S_w}{\partial z} + k_{fw} \lambda_n \Delta \rho g \right).$$

(4)

We note that the groups $\Psi$, $\Pi$ and $\Gamma$ are functions of the saturation only apart from $q_t = q_t(t)$ and $\frac{\partial S_w}{\partial z}$, which are non-local and depend on $z$ and $t$. We estimate $\frac{\partial S_w}{\partial z} \approx \Delta S_w H$ and assume that we can find a suitable estimator for the total flux $q_t(t) \approx \bar{q}_t$. Given these approximations, the groups are a function of $S_w$ only and the spatial differential is written as $\partial / \partial z = (\partial S_w / \partial z)(d/dS_w)$ via the chain rule. Hence, a timescale for the saturation change is estimated by linearizing each of the terms of Equation (4):

$$\phi_m \frac{\Delta S_w}{t} \approx \frac{\Delta S_w}{H} \left( \bar{q}_t \frac{d\Psi}{dS_w} + \frac{\Delta S_w}{H} \frac{d\Pi}{dS_w} + \frac{d\Gamma}{dS_w} \right) +$$

$$\frac{1}{t} \approx \frac{1}{\phi_m H} \left( \bar{q}_t \frac{d\Psi}{dS_w} + \frac{\Delta S_w}{H} \frac{d\Pi}{dS_w} + \frac{d\Gamma}{dS_w} \right),$$

(5)

where $\Delta S_w$ is estimated by $\Delta S_w \approx 1 - S_{wr}$. $H$ is the maximum penetration depth of CO$_2$ in the matrix block, that is, the depth inside the matrix block where the difference between the phase pressures of brine and CO$_2$ equals the capillary entry pressure. It is calculated as $H = L_z - P_c / (\Delta \rho g)$. This parameter is a natural length scale for the drainage process, as most of the drainage happens until the CO$_2$ front reaches this depth. This approach follows the developments of Di Donato et al. [2006], but with a key difference regarding the assumptions about the fluid properties: Di Donato et al. [2006] assume that $\mu_w \gg \mu_n$, which reduces the equation to a form that does not include the
group $\Psi$ and where the groups $\Pi$ and $\Gamma$ do not include the mobility of the non-wetting phase ($\lambda_n$); this assumption is not valid for CO$_2$-brine systems. We have shown in the last section that in some scenarios relevant to CO$_2$ storage applications the wetting phase properties do alter the behavior of the drainage process. Therefore, we do not make any assumptions regarding the fluid properties and aim to derive a general estimate of the timescale for any set of properties. The saturation derivatives in Equation (3.3) are estimated by considering the maximum of each group over the saturation range as a characteristic value. We therefore write:

$$
\frac{d\Psi}{dS_w} \approx \max_{S_w}(\Psi) \Delta S_w, \\
\frac{d\Pi}{dS_w} \approx \max_{S_w}(\Pi) \Delta S_w, \\
\frac{d\Gamma}{dS_w} \approx \max_{S_w}(\Gamma) \Delta S_w.
$$

To close the model, a characteristic value for $\bar{q}_t$ is needed. We note that the total flux is constant in $z$ but changes over time. It is highest at the onset of the drainage process and approaches zero when drainage is finished. We therefore use the maximum total flux to provide an estimate to $q_t$ ($\bar{q}_t = q_t(0)$). Isolating $q_t$ in Equation (2), integrating in space and assuming hydrostatic pressure in the non-wetting phase at the boundaries, we obtain:

$$
q_t(t) = \frac{1}{f_0^{L_z}} \int f \left[ -\rho_n g L_z - p_c(z = 0) + \int f_w \rho_w g + f_n \rho_n g - \lambda_n \frac{\partial p_c}{\partial z} dz \right],
$$

which gives us, assuming $S_w(z, t = 0) = 1$:

$$
\bar{q}_t = q_t(t = 0) = \frac{k_{frw}^{\text{MAX}}}{L_z \mu_w} (\Delta \rho g L_z - p_c(z = 0)).
$$

The capillary pressure at the top of the domain can be estimated by considering a high value of brine saturation, say $S_w = 0.9$, noting that at the onset of the drainage process only a small amount of non-wetting phase will have invaded the domain. The total flux estimate closes the model, and its performance will be assessed by using it in a transfer function that is tested against the high-resolution simulations described in the previous section. The evaluation of the saturation-dependent functions at their maximum may lead to an over-estimation of the transfer rate for some cases, particularly in the late-time regime of the drainage process. However, as shown in Section 3.5, the transfer function that is developed in the next section using this timescale predicts with good accuracy the drainage of the blocks for a large part of the drainage time.
3.4 Development of a new transfer function for CO$_2$ gravity-drainage

Most commercial simulators (e.g. Schlumberger [2014]; Computer Modelling Group [2016]) and scientific publications (e.g. Ahmed Elfeel et al. [2016]; Al-Kobaisi et al. [2009]; Beckner et al. [1991]; Bech et al. [1991]) rely on the work of Gilman [1986] to model gravity-induced drainage transfer functions \( \{T_w, T_n\} \) (Equation 3), sometimes applying a discretization of the matrix blocks [Pruess, 1985; Beckner et al., 1991]. These transfer functions model the matrix-fracture flow as proportional to the potential difference between the two continua. Mathematically, this translates to:

\[
T_n = \sigma \frac{k_m k_{rn}}{\mu_n} \left( p_n^f - p_n^m + \Delta \rho (h_n^f - h_n^m) g \frac{L_z}{2} \right),
\]

\[
T_w = \sigma \frac{k_m k_{rw}}{\mu_w} \left( p_w^f - p_w^m - \Delta \rho (h_n^f - h_n^m) g \frac{L_z}{2} \right),
\]

where \( \sigma \) is the shape factor, that accounts for the matrix area that is open for flow, \( k_m \) is the permeability of the matrix and \( k_{rn} \) are the relative permeabilities, that are typically evaluated upstream. However, despite intuitive and simple to implement in a dual-porosity simulator, it has been noted by other authors [Abushaikha and Gosselin, 2008; Ramirez et al., 2009] that this model fails to capture gravity drainage processes accurately, specifically if the blocks are tall. Moreover, it is important to note that the transfer functions defined by Equation (11) do not converge to the correct limit \( V_{CO}_2^{max} \) as the transfer ceases, and will therefore over-estimate the final storage of CO$_2$ at the matrix-block scale. This is typically corrected using pseudoization techniques that adjust the final amount of non-wetting phase that drains the matrix, at the cost of misrepresenting the drainage dynamics even more [Abushaikha and Gosselin, 2008; Schlumberger, 2014].

As shown later in this section, the mismatch between the storage results given by high-resolution block simulations and the results given by Equation (11) are specially high when considering rock and fluid properties relevant to CO$_2$ storage applications.

The timescale \( \tilde{t} \) defined in Equation (3.3) is used to develop an improved transfer function that captures the dynamics of CO$_2$-induced gravity-drainage. We start by defining the transfer rate coefficient \( \beta \) as:

\[
\beta = \frac{1}{\tilde{t}}.
\]

We then use \( \beta \) on an exponential model, as initially proposed by Aronofsky et al. [1958] and later on used by Kazemi et al. [1992], Schmid and Geiger [2012] and Schmid and Geiger [2013] to model spontaneous imbibition and by Zhou et al. [2014] to model diffusive transfer of CO$_2$ in fractured reservoirs. We therefore write the relative transfer
of CO\textsubscript{2} to the matrix by gravity drainage as:

\[ \frac{V_{\text{CO}_2}(t)}{V_{\text{CO}_2}^{\text{max}}} = 1 - e^{-t/\tilde{t}} \equiv 1 - e^{-\beta t}. \]  \hspace{1cm} (13)

Differentiation of this expression with respect to time and multiplication by a smooth activation function \( F(S_{nf}) \) leads to:

\[ \phi_m \rho_{nm} \frac{\partial S_{nm}}{\partial t} = T_n = \phi_m \rho_{nm} \beta F(S_{nf}) (S_{nm}^{\text{max}} - S_{nm}), \]  \hspace{1cm} (14)

where \( S_{nm}^{\text{max}} \) is the average saturation corresponding to the maximum volume of CO\textsubscript{2} a block can store. The activation function ensures a smooth activation of the transfer only when CO\textsubscript{2} is available in the fracture cell. It is defined \cite{Lu et al., 2008} as:

\[ F(S_{nf}) = \frac{1 - e^{-\sqrt{k_f^*/k_m S_{nf}}}}{1 - e^{-\sqrt{k_f^*/k_m}}}, \]  \hspace{1cm} (15)

where \( k_f^* \) is a measure of the permeability in the fracture cell, taken here as max\{\( k_{fx}, k_{fy}, k_{fz} \)\}. The activation function ensures the transfer starts when the fractures are saturated by CO\textsubscript{2}. The transfer ceases exactly when the block is saturated by the maximum amount of CO\textsubscript{2}. It is important to emphasize that a general assumption of transfer functions like the one defined above is that all the matrix blocks within a simulation grid block are similar and are surrounded by CO\textsubscript{2} once the plume arrives at this point. This is a common assumption done in the derivation of transfer functions for dual-porosity models, that is particularly reasonable when the vertical dimensions of the block are larger than the horizontal ones, such as in the In Salah CO\textsubscript{2} storage project \cite{Iding and Ringrose, 2010; Eiken et al., 2011}.

As phases are assumed incompressible, summation of the phase equations in the matrix (last two equations of 3) leads to \( T_w = -T_n \). We note that this expression is very similar to the one suggested by \textit{Di Donato et al.} \cite{Di Donato et al., 2006}, but with a different transfer rate coefficient (parameter \( \beta \)). \textit{Di Donato et al.} \cite{Di Donato et al., 2006} suggests the calculation of \( \beta \) as:

\[ \beta = \left( \frac{1}{n_w} \right) \omega_g + (r - 1) \omega_c, \]  \hspace{1cm} (16)

where \( r \) is the gravity/capillary ratio, given by \( r = \Delta \rho g L_z/P_c \), and \( \omega_g \) and \( \omega_c \) are characteristic timescales for gravity and capillary forces, given by \( \omega_g = (k_{rvu}^{\text{max}} \Delta \rho g)/(\phi_m H) \) and \( \omega_c = (k_{rvu}^{\text{max}} n_p P_c)/(\phi_m H^2) \). The \((1/n_w)\) and \((r - 1)\) factors multiplying each timescale were derived empirically by matching the transfer expression to high-resolution one-dimensional block simulations. We note that the expression derived in this work contains no parameters that were fitted to numerical simulations, in contrast to other approaches.
3.5 Evaluation of transfer functions

Figures 4(a) and 5(a) show a comparative analysis between the transfer model proposed in this work and the one proposed by Gilman [1986]. The curves corresponding to the latter were generated by running a 0D dual-porosity model of single fracture and matrix cells, and tracking the saturation of CO$_2$ in the matrix block over time. No correction of the final volume of CO$_2$ in the block was applied here; the transfer is implemented as shown in Equation (11). For the sugar cube geometry (Figure 4(a)), each case has the same position as in Figure 3, but the circles are now scaled by the relative integral error of the transfer model defined by Equation (13). The same applies for the match stick geometry. The relative integral error is defined as $E_{\text{model}} = \int |I_{\text{num}} - I_{\text{model}}| \, d\log t / \int I_{\text{num}} \, d\log t$, where $I_{\alpha}$ is the normalized stored volume of CO$_2$ for the model $\alpha$. Graphically, for each model, $E_{\text{model}}$ represents the ratio between the area between the model and numerical curves and the area below the numerical curve in Figures 4(b) and 5(b). For $E_{\text{model}} = 0$, the match is perfect. The error of Gilman’s expression is represented as empty circles in the same positions of the solid circles, and also scaled by $E_{\text{model}}$. Actual error values are shown in the figure for the cases with high $t_{95}$ in the plot for reference. For the color pattern used to identify each circle on the chart, please refer to Figure 3.

Figures 4(a) and 5(a) show that the model proposed in Equation (13) provides much more accurate results compared to the one given by Equation (11) for all cases (solid circles are always inside the empty circles). This is especially true for the match stick cases, which consist of fracture geometries extremely favourable to storage. The transfer model given by Equation (11) misrepresents the storage dynamics by a factor as high as $\approx 325\%$ for the match stick geometry and $\approx 139\%$ for the sugar cube geometry, both for the cardium#2-shallow-cold-low-P case. The maximum error incurred by the proposed model is $\approx 23\%$ for the match stick geometry (viking#2-shallow-cold-high-P case) and $\approx 16\%$ for the match stick geometry (cooking-lake-deep-warm-high-P case). The best results are achieved for the high-storage cases (top part of the chart in Figures 4(a) and 5(a)). Figures 4(b) and 5(b) show representative storage curves for some high storage cases. In these plots, the model of Di Donato et al. [2006] is also shown. The proposed model (dashed lines) seems to represent, with good accuracy, the whole extent of the drainage dynamics for most of the cases. The nisku#1 cases have a higher value of the Corey exponent ($n_w = 2.8$). This induces longer late-time storage dynamics (the proposed model over-estimates storage at late time for the green curves). However, most of the transient dynamic is cap-
tured even for these cases. The model of 
Di Donato et al. [2006] - despite improving dras-
tically over the one proposed in Gilman [1986] - appears to underestimate the storage for all the cases. We believe this is directly linked to neglecting the viscous timescale (first term of Equation (3.3)), as the work of Di Donato et al. [2006] was focused on oil-gas systems, assuming \( \mu_w \gg \mu_n \). The proposed model shows smaller errors for all cases when compared to the work of Di Donato et al. [2006]. For all cases, Gilman [1986] over-estimates the transfer rate by several orders of magnitude and fails to represent the drainage pro-
cess with any accuracy. This error is particularly high for match stick geometries, where the time to reach maximum recovery shows a difference that can reach the order of mag-
nitude of a thousand days when compared to the high-resolution simulations. These re-
sults were also observed by Abushaikha and Gosselin [2008]. The results shown in this section provide an indication that our new model can be successfully used to model CO
\(_2\) storage in NFRs.

4 Field scale considerations

The previous sections have focused on the storage of CO\(_2\) at the scale of a matrix
block. The negative impact of fractures on storage is summarized in Figure 3(b), which shows the percentage of volume (or mass, as we consider incompressibility of CO\(_2\) in su-
percritical state) that is lost when a system of interconnected fractures is present in the formation. This figure shows that fractures can reduce the CO\(_2\) storage in a single block to values as low as 5% of the effective pore volume. This happens because a matrix block surrounded by CO\(_2\) will be drained just until capillary and gravity forces balance. There are cases, however, in which good storage performance can be achieved, particularly for low capillary pressure levels and for warm basins. This static analysis show that a rea-
sonable amount of CO\(_2\) may be stored in a fractured reservoir depending on the geolog-
ical environment.

Another aspect of concern regarding CO\(_2\) storage in NFRs is the fate of the CO\(_2\)
plume. Since fractures have typically conductivities that are orders of magnitude higher than that of the rock matrix, it is usually speculated whether injected CO\(_2\) may quickly flow through the fracture system without a significant volume of it being transferred to the rock matrix. We investigate the impact of fractures at the field scale by running two-
dimensional simulations of CO\(_2\) injection in a conceptual anticline geometry. We first compare the results of injection of a certain amount of CO\(_2\) in a unfractured formation
with the injection of the same amount in a formation that has the same properties of
the rock matrix, but shows the presence of an interconnected fracture system. We then
investigate why and how CO\(_2\) injection rates should be limited in order to avoid the spilling
of CO\(_2\) through the fracture system without allowing for transfer to the matrix.

4.1 Setup of the numerical simulation experiments

The numerical experiments shown hereafter correspond to CO\(_2\) injection in the ge-
ometry representing a symmetric anticline, as shown in in Figure 6. The anticline dips
at \(\approx 2.8^\circ\) (25 m/500 m). A well that is completed over the entire thickness of the for-
mation \((L_z = 100\) m\) injects CO\(_2\) at rates that will be specified for each experiment.

No-flow boundary conditions are considered at the top and bottom of the model, rep-
resenting a cap rock and an underlying non-permeable formation. We consider the lat-
eral boundaries open for flow and at hydrostatic pressure of the resident fluid, which is
brine. Simulations are carried out using MRST [Lie et al., 2011]. The corner-point grid
structure is used to discretize the domain. \(N_x = 101\), \(N_y = 1\) and \(N_z = 100\) blocks
are used for all the simulations (the extra block in x-direction is used to ensure symme-
try of the grid).

The fracture system is represented as a homogeneous medium with no capillary pres-
sure and each fracture cell has a porosity of \(\phi_f = 0.01\) [Firoozabadi and Thomas, 1990].
No residual saturations and quadratic relative permeabilities are assumed for the frac-
ture system [Rossen and Kumar, 1992]. The absolute permeability of the fracture sys-
tem is set to be anisotropic: \(k_{fx} = 405\) mD and \(k_{fz} = 4053\) mD, corresponding to a
nearly vertical set of fractures. These are realistic values taken from the In-Salah Gas
Joint Venture CO\(_2\) storage project [Cavanagh and Ringrose, 2011] and were found via
discrete fracture network (DFN) modelling [Iding and Ringrose, 2010]. Four cases are
considered in the forthcoming analysis. Two cases with high drainage times (viking#2-
shallow-cold-low-P\(_c\) and cardium#2-deep-warm-low-P\(_c\)) and two further cases with low
drainage times (nisku#1-shallow-cold-low-P\(_c\) and cooking-lake-shallow-warm-high-P\(_c\)).
These cases define the rock properties for the unfractured simulations and \(\beta\) and \(S_{\text{num}}^{\text{max}}\)
for the dual-porosity simulations (see Table 2 for a summary of the selected cases).
4.2 Impact of fractures in the field-scale storage of CO$_2$

Figure 7 shows a comparison of CO$_2$ storage in fractured and unfractured formations. As the existence of a fracture system may not be known in advance, we aim at understanding how an operation that was designed for a unfractured formation would be affected by the presence of fractures. This situation occurred in the In Salah Project, where the existence of a fracture system was not recognized before the injection started [Iding and Ringrose, 2010]. Hence, we compare the results of CO$_2$ injection in a fractured formation, using the dual-porosity model developed in Section 3.4, with the injection in an unfractured formation. In our simulations, a volume equal to the effective pore volume available for safe storage on the structural trap, $PV_{\text{eff}}$, (see Figure 6) is injected over 1000 days. After this time, injection ceases as further injection would cause CO$_2$ to spill through the boundaries, even without the presence of fractures.

Figure 7(a) and Figure 7(b) show the CO$_2$ saturation fields at $t = 1000$ days before injection ceases for the fractured and unfractured simulations, respectively. A well-developed plume is seen in the unfractured simulation, while in the fractured case, the presence of a high-permeability fracture system induces the quick segregation of CO$_2$ at the top of the fractures. The transfer to the matrix takes time. The time-scale is determined by the transfer rate coefficient $\beta$ (see Equation (13)). Figure 7(c) shows the mass of CO$_2$ in the system for the fractured and unfractured models. We note a decrease of $\approx 27\%$ in the stored CO$_2$ volume when fractures are added to the system. If the CO$_2$ that is stored in the matrix (dashed line) is compared to the case where the fractures are absent (solid blue line), the difference ($\approx 32\%$) corresponds precisely to $100\% - V_{CO_2}^{\%}$ (see Section 3.2 and Figure 3(b)). Therefore, since most of the CO$_2$ is stored in the matrix, $V_{CO_2}^{\%}$ may be used as a correction factor for volumetric CO$_2$ storage estimates, at least as a first-order approximation. This is more evident in Figure 8, where we plot the injected volume normalized by the effective pore volume ($PV_{\text{eff}}$). CO$_2$ in the matrix (dash-dotted lines) match $V_{CO_2}^{\%}$ approximately, as explained above. The difference between the solid curves and the thick gray line represents the amount of CO$_2$ that left the system through the boundaries, i.e. spilling the anticline through the top corners of the model. An ideal operation would ensure that all the injected CO$_2$ remains in the domain, where it can be safely trapped. The spill times depend not only on $\rho$, injection rate and thickness of the formation (which determines the shape of the plume in the fracture system) but also on the transfer rate $\beta$ and $S_{nm}^{\max}$. Compare, for instance, the viking#2 and nisku#1
cases, that correspond to the same environment (shallow-cold). If there was no trans-
fer, the stored CO\textsubscript{2} for these two cases should be the same, as the rock and fluid prop-
erties would be the same. However, because the transfer dynamics is faster for the nisku#1
case (see Figure 4(b)), injected CO\textsubscript{2} is transferred faster to the matrix, avoiding the early
spill time seen in the viking#2 case. There is, in fact, an optimal injection rate that avoids
spilling if the correct amount of CO\textsubscript{2} is injected for each case. This topic is approached
in the next section.

4.3 Injection rate considerations

We now explore aspects regarding injectivity of CO\textsubscript{2} in NFRs. We disregard the
injection rate limitations imposed by the integrity of the cap rock in this analysis, not-
ing that the fractures will allow for higher injectivity compared to an unfractured for-
mation. We now inject the maximum amount of CO\textsubscript{2} that the matrix can store for each
case, which is given by $V_{\text{inj}} = S_{\text{nm}}^{\text{max}} \phi n V_a$, where $V_a$ is the volume of the anticline (the
volume of the formation above the red dashed line in Figure 6). We consider three dif-
ferent injection rates: $V_{\text{inj}}/(1000 \text{ days})$, $V_{\text{inj}}/(500 \text{ days})$ and $V_{\text{inj}}/(100 \text{ days})$. The re-
results are summarized in Figure 9. We focus the discussion, initially, on Figure 9(a). The
difference between injected CO\textsubscript{2} (solid line) and stored CO\textsubscript{2} (dashed line) is the amount
of CO\textsubscript{2} that spilled. We note that all three initial injection rates (blue, red and black
lines) are high enough so that CO\textsubscript{2} travels quickly through the fracture system without
allowing for enough time to transfer to the matrix. If the injection rate is reduced to $V_{\text{inj}}/(1600
\text{ days})$ (magenta curve), the injected CO\textsubscript{2} is safely trapped in the anticline. The same pro-
cedure is applied to the other three cases to reveal the injection rates that minimize the
spilled CO\textsubscript{2}. As mentioned in the previous section, one must be more conservative re-
grarding the injection rate for the low $\beta$ cases (viking#2 and nisku#1). Ideal injection
rates are, in fact, monotonically increasing with $\beta$.

The following simple model serves as an estimation of the maximum injection rate
in NFRs:

$$q_{\text{inj}}^{\text{max}} = \frac{V_{\text{inj}}}{t_{95}}.$$  \hspace{1cm} (17)

This model implies that one should inject at a rate that is no higher than the maximum
amount one can store in the rock matrix divided by the time it takes to saturate 95%
of the matrix pore volume. $t_{95}$ may be easily calculated by inverting Equation 13 and
evaluating it for $V_{\text{CO}_2(t)}/V_{\text{CO}_2}^{\text{max}} = 0.95$. Although this model has some physical reasoning behind it, it lacks a fundamental component for a more accurate estimate, which is the geometrical component of the CO$_2$ plume in the fracture system. Table 2 shows a summary of the injection rates found via numerical simulation and using the model given by Equation (17). We define the accuracy factor of the injection rate estimate as $q_{\text{max inj}}^\text{max}/q_{\text{num}}$, where $q_{\text{num}}$ is the optimal injection rate obtained from numerical simulations (magenta curves in Figure 9). The accuracy factor ranges from $\approx 4$ to $\approx 7$. This model, despite simple, provides an order-of-magnitude estimate of the optimal injection rate. It should be noted that the accuracy factors are overestimated with the 2D numerical simulations carried in this section. The consideration of a third dimension in the y direction would lead to a higher $q_{\text{num}}$, making this value closer to the proposed model given by Equation 17. This gives us indications that this model could serve as a good initial indicator of the magnitude of the injection rate that avoids the early-spill of CO$_2$ for anticlines.

5 Summary and conclusions

Carbon capture and storage (CCS) is a promising technique to reduce the concentration of greenhouse gases in the atmosphere. Fractured reservoirs are ubiquitous across the world. A large percentage of the world’s hydrocarbon resources come from naturally fractured reservoirs, that could be later used for CO$_2$ storage. However, fractured reservoirs are not typically considered as formations with potential to safely store CO$_2$. The main concerns regarding storage in fractured formations are the high conductivity of the fracture system, that may lead to lost control of the CO$_2$ plume and capillary forces that will tend to keep CO$_2$ outside the unfractured rock matrix.

Simulating the dynamics in naturally fractured reservoirs is a complex and computationally-intensive task, as there are several mechanisms by which fractures and matrix exchange fluids. Moreover, fractures introduce a new timescale to fluid flow, as the transfer to the matrix will typically be much slower than the flow in the fractures. Yet, numerical simulations are extremely useful to obtain insights about the reservoir dynamics during CO$_2$ storage in fractured formations. To simplify the computational system, dual-porosity models have been used for many years due to their simplicity and computational efficiency, as they upscale the transfer behaviour and average properties of the fracture system. A fundamental ingredient of dual-porosity models are transfer functions that describe the
fluid exchange rate between fractures and matrix. Currently existing transfer functions are designed for oil-gas systems, and fail to represent the dynamics of drainage induced by supercritical CO$_2$. Therefore, one of the key contributions of this work was the development of a new transfer function that models CO$_2$-induced gravity drainage accurately. This transfer function is based on a timescale analysis of the physics of immiscible multi-phase flow combined with an exponential model, as suggested initially by Di Donato et al. [2006]. A more formal treatment of each timescale term, combined with the inclusion of the viscous term, improves the original model of Di Donato et al. [2006] and the widely used model of Gilman [1986]. Our new model requires no fitting to numerical simulations, is consistent and captures the drainage process accurately. The transfer function presented here is easy to implement in any dual-porosity simulator.

At the matrix-block scale, we show that the percentage of the matrix-block volume that is effectively used for storage, is higher for deep formations in cold basins and lower for shallow formations in warm basins ($\approx 40\%$ vs $\approx 15\%$). In contrast to this result, deep formations in cold basins will lead to a higher mass of CO$_2$ stored per unit volume, due to the high density of the supercritical fluid. This indicates a competing behavior of CO$_2$ density in fractured reservoirs: for a fixed brine density $\rho_b$, a high value of $\rho_c$ increases the stored mass per unit volume, but decreases the stored mass on each block due to the decreased density difference $\Delta \rho$. Our studies show that in a shallow formation in a warm basin the negative impact of fractures on the storativity of CO$_2$ is less pronounced. Therefore, in such formations, the existence of an interconnected system of fractures would not grossly impact the final storage.

At the field scale, we have shown that the injection rate for a fractured anticline must be designed to avoid what is termed here as “early spill”: the fast flow of CO$_2$ through the fracture system without significant storage in the matrix. We have shown that the spill time for a conceptual anticline geometry is heavily dependent on the transfer rate between the two continua. An initial model to estimate the order of magnitude of the ideal injection rate is proposed (Equation 17). Numerical experiments shown in Figure 9 indicate that this model captures the order of magnitude of the optimal injection rate that avoids early spill, even though it does not consider the geometrical aspect of the CO$_2$ plume in the fracture system. Although we understand that the major injection rate design criteria for CO$_2$ storage is still the integrity of the sealing formation, we point out
in this work that a new aspect of injection rate determination must be taken into consideration when using an NFR for storage.

General guidelines for CO$_2$ storage in NFRs include:

• The correction of storage estimates to account for a loss in storativity caused by the presence of a fracture system;

• The use of numerical simulations with the transfer function developed here to evaluate the spill time and to design an optimal injection plan for the fractured aquifer.

The model given by Equation (17) gives an order of magnitude of this injection rate, but must be used with caution as it does not consider geometrical aspects of the formation.

Although this work consists of a simplified first-order physics analysis, we believe it is an important initial step in the analysis of CO$_2$ storage in NFRs, which, in principle, could be used for CO$_2$ storage if the geological conditions are right and the injection rates are managed appropriately.

Acknowledgments

This material is based upon work supported by the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) under grant FE0023323. This project is managed and administered by Princeton University and funded by DOE/NETL and cost-sharing partners. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the U.S. Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the U.S. Government or any agency thereof. The authors also thank the financial support provided by Energi Simulation for supporting Sebastian Geiger’s Chair for Carbonate Reservoir Simulation and the reviewers for the insightful comments that helped improving this work. All data for this paper are properly cited and referred to in the reference list. Simulations were carried out with the open
source code MRST, and the related Matlab scripts are available online at the Software
section of the website http://carbonates.hw.ac.uk.

Figure 1. (a) Conceptual representation of CO$_2$ injection in a fractured reservoir. Injected
CO$_2$ (in green color) quickly saturates the fractures (light-gray lines), that generally have low
pore volume and high permeability. (b) Conceptualization of different transfer mechanisms re-
 sponsible for transfer of CO$_2$ (green) and brine (blue) between a matrix block and the surround-
ing fractures. Geomechanical effects in the transfer are neglected here, but may be important for
some formations. Arrows indicate the main direction of CO$_2$ and brine flow on each mechanism
(green and blue, respectively). The dominant mechanisms in a well-connected fracture network
are buoyancy redistribution and capillary imbibition.
Table 1. Physical parameters used to evaluate gravity drainage on a block scale. Each combination of environment, sample and capillary pressure level is considering, giving a total of 40 simulation cases. Environments follow the definition of Nordbotten and Celia [2012]. Samples were extracted from experiments carried by Bennion and Bachu [2006]. Two capillary pressure cases were considering respecting the maximum capillary entry pressure for CO$_2$ invasion, given the block size ($L_z = 20$ m).

<table>
<thead>
<tr>
<th>Case</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Environment</strong></td>
<td></td>
</tr>
<tr>
<td>shallow-cold</td>
<td>$\rho_w = 1012$ kg/m$^3$, $\rho_n = 714$ kg/m$^3$, $\mu_w = 0.8$ cP, $\mu_n = 0.05$ cP</td>
</tr>
<tr>
<td>shallow-warm</td>
<td>$\rho_w = 998$ kg/m$^3$, $\rho_n = 714$ kg/m$^3$, $\mu_w = 0.8$ cP, $\mu_n = 0.05$ cP</td>
</tr>
<tr>
<td>deep-cold</td>
<td>$\rho_w = 995$ kg/m$^3$, $\rho_n = 733$ kg/m$^3$, $\mu_w = 0.38$ cP, $\mu_n = 0.06$ cP</td>
</tr>
<tr>
<td>deep-warm</td>
<td>$\rho_w = 945$ kg/m$^3$, $\rho_n = 479$ kg/m$^3$, $\mu_w = 0.2$ cP, $\mu_n = 0.04$ cP</td>
</tr>
</tbody>
</table>

| **Sample**         |                                                                         |
| cardium#2 (Sandstone) | $k = 21$ mD, $S_{wr} = 0.42$, $n_w = 1.2$, $n_n = 1.3$, $k^{max}_{rn} = 0.13$, $\phi_m = 0.16$ |
| viking#2 (Sandstone) | $k = 21$ mD, $S_{wr} = 0.42$, $n_w = 1.7$, $n_n = 2.8$, $k^{max}_{rn} = 0.26$, $\phi_m = 0.19$ |
| Wabamun#2 (Sandstone) | $k = 67$ mD, $S_{wr} = 0.57$, $n_w = 1.4$, $n_n = 2.1$, $k^{max}_{rn} = 0.19$, $\phi_m = 0.15$ |
| nisku#1 (Carbonate)  | $k = 46$ mD, $S_{wr} = 0.33$, $n_w = 2.8$, $n_n = 1.1$, $k^{max}_{rn} = 0.18$, $\phi_m = 0.1$ |
| cooking-lake (Carbonate) | $k = 65$ mD, $S_{wr} = 0.48$, $n_w = 1.4$, $n_n = 5.6$, $k^{max}_{rn} = 0.07$, $\phi_m = 0.1$ |

<table>
<thead>
<tr>
<th><strong>Capillary Pressure Level</strong></th>
<th><strong>Values</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>high-$P_c$</td>
<td>$P_e = 40$ kPa (match stick) and $P_c = 25$ kPa (sugar cube)</td>
</tr>
<tr>
<td>low-$P_c$</td>
<td>$P_e = 10$ kPa (match stick) and $P_c = 5$ kPa (sugar cube)</td>
</tr>
</tbody>
</table>
Table 2. Summary of the selected cases for the field-scale simulations.

<table>
<thead>
<tr>
<th>Case</th>
<th>$\beta$ [1/s]</th>
<th>$S_{\text{num}}$ [-]</th>
<th>$q_{\text{num}}$ [m$^3$/day]</th>
<th>$q_{\text{inj}}^\text{max}$ [m$^3$/day]</th>
<th>$q_{\text{inj}}^\text{max}/q_{\text{num}}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>viking#2</td>
<td>$8.48 \times 10^{-8}$</td>
<td>0.39</td>
<td>894</td>
<td>3499</td>
<td>$\approx 4$</td>
</tr>
<tr>
<td>nisku#1</td>
<td>$3.22 \times 10^{-7}$</td>
<td>0.45</td>
<td>1158</td>
<td>8068</td>
<td>$\approx 7$</td>
</tr>
<tr>
<td>cooking-lake</td>
<td>$1.99 \times 10^{-6}$</td>
<td>0.21</td>
<td>5406</td>
<td>23270</td>
<td>$\approx 4$</td>
</tr>
<tr>
<td>cardium#2</td>
<td>$6.03 \times 10^{-7}$</td>
<td>0.45</td>
<td>4634</td>
<td>24175</td>
<td>$\approx 5$</td>
</tr>
</tbody>
</table>

Figure 2. Conceptual picture of the block geometries and boundary conditions for (a) the sugar cube geometry and (b) the match stick geometry. Fractures are modeled as boundary conditions on the matrix blocks. Green dashed lines represent open boundary faces, open for CO$_2$ flow, while solid black lines in the match stick model represent no-flow boundaries. Only a projection in the x-z plane is shown, but geometries are 3D with $L_y = L_x$. 
Figure 3. Analysis of the maximum CO₂ storage and drainage timescales on a single block for the sugar cube geometry. (a) Drainage time vs. stored mass of CO₂; (b) Drainage time vs. relative stored volume of CO₂. The relative volume provides a percentage measure of the pore volume not effectively used for storage due to the presence of a fracture system. Small circles correspond to high-Pₚ cases.
Figure 4. Evaluation of transfer functions for the sugar cube matrix geometry. Circles edges and fills are colored following the pattern in Figure 3. (a) The size of the circle is proportional to the error when using Gilman [1986] (non-solid circles) and the transfer function proposed in this work (solid circles) to model the drainage process, relative to the 3D numerical model. (b) Representative drainage curves showing the reference solution, given by high-resolution simulations of a single block (solid lines), the Gilman [1986] transfer function (dotted line), the Di Donato et al. [2006] transfer function (dash-dotted line) and the transfer function proposed in this work.
Figure 5. Evaluation of transfer functions for the match stick matrix geometry. Circles edges and fills are colored following the pattern in Figure 3. (a) The size of the circle is proportional to the error when using Gilman [1986] (non-solid circles) and the transfer function proposed in this work (solid circles) to model the drainage process, relative to the 3D numerical model. (b) Representative drainage curves showing the reference solution, given by high-resolution simulations of a single block (solid lines), the Gilman [1986] transfer function (dotted line), the Di Donato et al. [2006] transfer function (dash-dotted line) and the transfer function proposed in this work.
Figure 6. Conceptual picture of the anticline geometry considered for the simulations in Section 4. CO\(_2\) is injected on a well completed over the entire thickness of the anticline (green line). Injected CO\(_2\) is structurally trapped only in the upper portion of the anticline, between the dashed red line and the cap rock. Lateral faces are open for flow, and hydrostatic pressure of brine is assigned to these faces. No-flow boundary conditions are considered for the top and bottom boundaries, representing the overburden and underburden to the aquifer. Note that the picture is vertically exaggerated and the dip of the anticline is not to scale.
Figure 7. CO$_2$ saturation distributions for the viking#2-shallow-cold-low-$P_c$ properties, for (a) the fractured anticline (top fractures, bottom matrix) and (b) the unfractured anticline. (c) Injected and stored mass of CO$_2$ for both simulation cases. Storage efficiency is reduced in the fractured case, and CO$_2$ escapes through the boundaries (solid red line diverging from thick gray line at $\approx 400$ days), reflecting the fast flow of CO$_2$ through the fracture system.
Figure 8. Relative injected and stored volumes for the field-scale simulations. Time is normalized by 1000 days, when injection stops. Solid lines represent the total volume of CO$_2$ stored in the fractured anticlines, while dotted lines represent the total volume of CO$_2$ stored in the corresponding unfractured model. The difference between both curves shows the reduction in storage efficiency loss when a system of connected fractures exists in the formation.
Figure 9. Injected (solid lines) and stored mass (dashed lines) of CO\(_2\) for (a) viking#2, (b) nisku#1, (c) cooking-lake and (d) cardium#2 cases in the geometry depicted in Figure 6. Each case has its "optimal" injection rate, i.e. an injection rate that minimizes spilling of CO\(_2\).

References


1–11.


Journal, December.


March, R., F. Doster, and S. Geiger (2016). Accurate Early-Time and Late-Time Modeling of Countercurrent Spontaneous Imbibition. Water Resources Research,


