We study the physics of \textit{multiphase flow in porous media}.

We apply our theoretical, computational and experimental research to geophysical problems in the area of \textit{energy and the environment}.
Why?

- Multiphase flow plays a fundamental role in critical Earth processes
  - Methane venting
  - CO$_2$ sequestration
  - Water infiltration

- *Modus Operandi:* first, understand the process at the small scale; then, apply to the large (continental) scale
The four classical elements
sedimentary basins
sedimentary rocks more than 800m thick
faults
footprint of trapped CO$_2$
array of injection wells
storage capacity (Gt CO$_2$)

sedimentary basins
sedimentary rocks more than 800m thick
faults
footprint of trapped CO$_2$
array of injection wells
storage capacity (Gt CO$_2$)
Mixing from viscous fingering

- Key question: does viscous fingering enhance or reduce mixing?
  - *Creation of interfacial area*: enhances mixing
  - *Channeling*: reduces mixing
Mixing from gravitational instabilities

- Mixing is controlled by the scalar dissipation rate
- Mixing rate is constant and independent of Rayleigh number
Water infiltration in soil – lab experiments
Phase-field modeling

- **Origin**: mathematical description of phase transitions (Cahn & Hilliard, 1958)

- **Two key ideas**
  - The energy depends on the presence of interfaces
  - Sharp interfaces are replaced by diffuse interfaces

- **Order parameter** $\varphi$
  - labels “wet” and “dry” regions

$$\mathcal{E} = \mathcal{E}_{\text{bulk}} + \mathcal{E}_{\text{interf}} = f(\varphi) + \frac{\varepsilon}{2} |\nabla \varphi|^2$$
simulations

Cueto-Felgueroso & Juanes

experiments

Flekkøy et al. (Phys. Rev. E 2002)

Gomez, Cueto-Felgueroso & Juanes

Yao (MS Thesis, 1993)
Phase-field model of partial wetting


- Capillary tube

- Hele-Shaw cell
Methane venting from lake sediments and the continental shelf

- Contributes to atmospheric methane
- Powerful climate feedbacks

Courtesy of Katey Walter, UAF
Mode of methane invasion

- Invasion by capillary pressure
- Invasion by fracture opening

Essential physics: surface tension

Additional cohesion due to surface tension
Capillary invasion vs. fracturing
Jain & Juanes (J. Geophys. Res. 2009)

- Capillary invasion in a rigid medium dominates for coarse-grain sediments
- Gas invades by fracturing in fine-grain sediments
Transition from fingering to fracturing


- Competition between pressure forces (from capillarity and viscosity) and frictional resistance between grains

- Crossover among gas invasion regimes

\[ \Delta f_p \sim \gamma a + \eta v a \]

\[ \Delta f_f \sim \mu w/(L/d)^2 \]

a. viscous fingering  
b. capillary fingering  
c. fracturing
The Lifetime of Carbon Capture and Storage as a Climate Change Mitigation Technology

Michael Szulczewski
Christopher MacMinn
Howard Herzog
Ruben Juanes

MIT
http://juanesgroup.mit.edu

Fermilab Colloquium
January 30, 2013
How Big is the Problem, Really?

- In the United States alone …
  - Current emissions ~ 7 billion metric tons per year (7 GtCO₂/yr)
  - Coal-fired and gas-fired power plants ~ 35% ~ 2.4 GtCO₂/yr

- Take 1 GtCO2/yr (“1 unit”) …
  - That’s 1 billion tons per year, 10¹² kg/yr
  - At a reservoir density ~ 500 kg/m³, that’s 2×10⁹ m³/yr
  - 1 m³ = 6.25 bbl, 1 year = 365 days, gives 35 million barrels per day

- 1000 times the injection rate at Sleipner
  - ~ 1 Sleipner every two weeks for the next 50 years

And that is to address just 15% of current emissions
Storage Must be Understood at the Scale of Geologic Basins

- Deep, thin
- Capped by impermeable layers
- Horizontal or weakly sloped \( \vartheta \sim 1^\circ \)
- Slow natural groundwater through-flow
  \[ U_n < 1 \text{ m/year} \]

100 wells, 1 km spacing
Storage Capacity

• Storage capacity informs about the physical limitations of CCS, over which economic and regulatory limitations must be imposed

• We develop basin-scale capacity estimates based on fluid dynamics

• Two constraints:
  ‣ The footprint of the migrating CO2 plume must fit in the basin
  ‣ The pressure induced by injection must not fracture the rock

• Both constraints can be limiting in practice, and which one applies is dependent on the aquifer and the injection period
Some controversy

• “underground carbon dioxide sequestration via bulk CO2 injection is not feasible at any cost.” (Ehlig-Economides and Economides, *JPSE* 2010)

• “CCS can never work, US study says” (Canada Free Press on Ehlig-Economides and Economides, 2010)
Some controversy

• … and some rebuttals

  ‣ “Open or closed? A discussion of the mistaken assumptions in the Economides pressure analysis of carbon sequestration” (Cavanagh, Haszeldine, and Blunt, *JPSE* 2010)

  ‣ “The realities of storing carbon dioxide – A response to CO2 storage capacity issues raised by Ehlig-Economides & Economides” (Chadwick et al., *Nature Precedings*, 2010)
Traditional Approach

The volumetric equation for CO₂ resource calculation in saline formations with consistent units assumed is as follows:

$$ G_{\text{CO}_2} = A_t \ h_g \ \phi_{\text{tot}} \ \rho \ E $$

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Units</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$G_{\text{CO}_2}$</td>
<td>M</td>
<td>Mass estimate of saline formation CO₂ resource.</td>
</tr>
<tr>
<td>$A_t$</td>
<td>$L^2$</td>
<td>Geographical area that defines the basin or region being assessed for CO₂ storage calculation.</td>
</tr>
<tr>
<td>$h_g$</td>
<td>L</td>
<td>Gross thickness of saline formations for which CO₂ storage is assessed within the basin or region defined by $A_t$.</td>
</tr>
<tr>
<td>$\phi_{\text{tot}}$</td>
<td>$L^3/L^3$</td>
<td>Average porosity of entire saline formation over thickness $h_g$ or total porosity of saline formations within each geologic unit’s gross thickness divided by $h_g$.</td>
</tr>
<tr>
<td>$\rho$</td>
<td>$M/ L^3$</td>
<td>Density of CO₂ evaluated at pressure and temperature that represents storage conditions anticipated for a specific geologic unit averaged over $h_g$.</td>
</tr>
<tr>
<td>$E^{**}$</td>
<td>$L^3/L^3$</td>
<td>CO₂ storage efficiency factor that reflects a fraction of the total pore volume that is filled by CO₂.</td>
</tr>
</tbody>
</table>

* L is length; M is mass
**For details on $E$, please refer to Appendix 4.

Source: USDOE Methodology for Development of Geologic Storage Estimates for Carbon Dioxide, 2008
See also: Bachu et al., *IJGHGC* 2007
Traditional Approach

• Splitting the sources of trapping capacity  
  (Bachu et al., IJGHGC 2007)

  ‣ Stratigraphic traps

\[ M_{\text{CO}_2,\text{strat}} = \rho_{\text{CO}_2} V_{\text{trap}} \phi(1 - S_{wi})C_c \]

  ‣ Residual-gas traps

\[ M_{\text{CO}_2,\text{resid}} = \rho_{\text{CO}_2} V_{\text{sweep}} \phi S_{gr} \]

  ‣ Solubility traps

\[ M_{\text{CO}_2,\text{solub}} = V_{\text{aquifer}} \phi \rho_w X_{\text{CO}_2} C_s \]

  ‣ Mineral traps

  * Highly uncertain and time-dependent
Traditional Approach

• Splitting the sources of trapping capacity

“estimation of the CO$_2$ storage capacity through residual-gas trapping can be achieved only in local- and site-scale assessments, but not in basin- and regional-scale assessments.” (Bachu et al., IJGHGC 2007)

• Here we will show how to obtain basin-scale storage capacities that include residual and solubility trapping
The geologic setting of our migration model has two key features:

- basin scale
- line-drive array of wells

100 wells, 1 km spacing
Trapping Mechanisms

(Juanes et al., Water Resour. Res. 2006)
Dissolution by Convective Mixing
Modeling Approximations

- sharp interfaces
- negligible capillary forces
- negligible fluid compressibility
- thin aspect ratio (vertical flow equilibrium / “Dupuit Approx.”)
- homogeneous properties
- negligible rock compressibility

Fluid

- Bear
  *Elsevier 1972*

Aquifer

- Barenblatt et al.
  *Nedra 1972*

- Hesse et al.
  *SPE 2006*

- Nordbotten & Celia
  *JFM 2006*

- Kochina et al.
  *Int. J. Eng. Sci. 1983*

- Hesse et al.
  *JFM 2008*

- Juanes et al.
  *TiPM 2010*

- Barenblatt et al.
  *Nedra 1972*

- Hesse et al.
  *SPE 2006*

- Nordbotten & Celia
  *JFM 2006*

- MacMinn et al.
  *JFM 2010, 2011*
Migration without Dissolution

\[ \tilde{R} \frac{\partial \eta}{\partial \tau} + N_f \frac{\partial f}{\partial \xi} + N_s \frac{\partial}{\partial \xi} \left[ (1 - f) \eta \right] = 0 \]

\[ \eta = \frac{h}{H} \quad \tau = \frac{t}{T_c} \quad \xi = \frac{x}{L_c} \]

\[ N_f = 1 \quad N_s = \frac{\Delta \rho g k \lambda_g}{U_n} \sin \vartheta \]

\[ N_g = \frac{\Delta \rho g k \lambda_g}{U_n} \cos \vartheta \frac{(1 - S_{wc}) \phi H^2}{Q_i T_i/2} \]

\[ T_c = \frac{Q_i T_i/2}{U_n H} \quad L_c = \frac{Q_i T_i}{2H(1 - S_{wc})\phi} \]
Migration without Dissolution

\[
\tilde{R} \frac{\partial \eta}{\partial \tau} + N_f \frac{\partial f}{\partial \xi} + N_s \frac{\partial}{\partial \xi} \left[ (1 - f) \eta \right] - N_g \frac{\partial}{\partial \xi} \left[ (1 - f) \eta \frac{\partial \eta}{\partial \xi} \right] = 0
\]

g.w. flow \quad \text{up-slope migration} \quad \text{spreading}

- Complete analytical solution
- Interaction between flow and slope

Juanes & MacMinn  
SPE 2008

Juanes et al.  
TiPM 2010

MacMinn et al.  
JFM 2010
Efficiency Factor

• Macroscopic measure of storage efficiency
  - How much aquifer is “used” per unit CO₂ stored?

\[ \varepsilon = \frac{\text{volume of CO}_2}{\text{volume of aquifer}} = \frac{2}{\xi T} \]

★ How does this depend on \( M, \Gamma, N_s/N_f \) ?

Bachu et al.
Int. J. GHGC 2007
Efficiency Factor

The Footprint of the CO₂ Plume during Carbon Dioxide Storage in Saline Aquifers: Storage Efficiency for Capillary Trapping at the Basin Scale

Ruben Juanes · Christopher W. MacMinn · Michael L. Szulczewski

doi:10.1017/S0022112010003319

CO₂ migration in saline aquifers. Part 1. Capillary trapping under slope and groundwater flow

C. W. MacMinn¹, M. L. Szulczewski² and R. Juanes²†
Storage Efficiency

\[
\frac{\Gamma}{\mathcal{M}} \sim \frac{\Gamma^2}{0.9\mathcal{M} + 0.5}
\]

Juanes et al.  
*TiPM 2010*  
MacMinn et al.  
*JFM 2010*
Dissolution by Convective Mixing

Convective mixing:

- $\text{CO}_2$ dissolves into ambient brine
- Density of brine increases with $\text{CO}_2$ content
- Boundary layer is unstable
- Constant average mass flux

- Elder
  * JFM 1968
- Ennis-King et al.
  * Phys. Fluids 2005
- Wooding et al.
  * WRR 1997
- Riaz et al.
  * JFM 2006
- Weir et al.
  * TiPM 1996
- Pau et al.
  * AWR 2010
- Backhaus et al.
  * PRL 2011
- Neufeld et al.
  * GRL 2010
- Hidalgo et al.
  * PRL 2012
Migration with Dissolution

\[
\frac{\tilde{R}}{\partial \tau} \frac{\partial \eta}{\partial \tau} + N_f \frac{\partial f}{\partial \xi} + N_s \frac{\partial}{\partial \xi} \left[ (1 - f) \eta \right] - N_g \frac{\partial}{\partial \xi} \left[ (1 - f) \eta \frac{\partial \eta}{\partial \xi} \right] = -\tilde{R} N_d
\]

Essential features:

- CO_2 dissolves from the plume at a constant rate
- Dissolution does not drive residual trapping
- Dissolution stops when the water column saturates
Migration with Dissolution

Interplay between dissolution, saturation, and migration: two limiting cases

- **Slow saturation**: dissolution not limited by the amount of water beneath the plume
- **Instantaneous saturation**: only leading edge dissolves; water elsewhere saturated

\[
N_d = 0 \\
N_d = 0.04 \\
N_d = 0.1 \\
N_d = 4
\]
Analytical Solutions with Dissolution

We can obtain semi-analytical solutions to the migration model in the two limits:

- **Slow saturation limit:** plume and curtain of saturated water do not interact
- **Instantaneous saturation limit:** water beneath the plume is completely saturated

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doi:10.1017/jfm.2011.379

**CO₂ migration in saline aquifers. Part 2. Capillary and solubility trapping**

C. W. MacMinn¹, M. L. Szulczewski² and R. Juanes²†
Experiments of Dissolving Gravity Currents

Convective mixing stops the plume
We estimate aquifer capacity by using the model in reverse.

**Forward**
- Set injection volume
- Calculate footprint

**Reverse**
- Set footprint to aquifer size
- Calculate injection volume
Pressure Model

The geologic setting of our pressure model has three key features:

- basin scale
- line-drive array of wells
- multiple layers

100 wells, 1 km apart
Model Features

• Lateral pressure dissipation
  ‣ no-flow at faults and pinchouts
  ‣ constant pressure at outcrops

• Vertical pressure dissipation
  ‣ major contributor to pressure dissipation

• Ramp-up, ramp-down injection scenario
Vertical Pressure Dissipation

We model the overburden and underburden with average, anisotropic permeabilities.

\[
\begin{align*}
\text{high permeability unit:} & \quad k_{\text{lqifier}} \\
\text{low permeability unit:} & \quad k_{\text{caprock}} \\
\text{aquifer:} & \quad k_{\text{aqusifer}} \\
\end{align*}
\]

\[
\begin{align*}
\bar{k}_x & = \frac{1}{2} k_{\text{aquifer}} \\
\bar{k}_z & = 2 k_{\text{caprock}} \\
\end{align*}
\]
Pressure Storage Capacity

We estimate pressure-limited capacity by using the model in reverse.

**Forward**
- Set injection scenario
- Calculate maximum pressure

**Reverse**
- Set maximum pressure to fracture pressure
- Calculate injection scenario and volume
Pressure Storage Capacity

- Pressure capacity depends on the duration of injection $T$

- If the aquifer is laterally infinite and the overburden and underburden are impermeable, then capacity grows as $\sqrt{T}$
Pressure Storage Capacity

If the aquifer is laterally bounded, the capacity growth deviates from $\sqrt{T}$.
Storage capacity is dynamic

- For short durations of injection, overpressure is more limiting
- For long durations of injection, CO$_2$ migration is more limiting

Capacity Estimates from Fluid Dynamics

Szulczewski and Juanes (GHGT 2010)
Capacity Estimates for the United States

• Studied 20 well arrays in 12 saline aquifers throughout the U.S.
  ‣ Largest, most structurally sound, best characterized aquifers
  ‣ Capacities between 1 and 18 GtCO₂

• 8 were limited by pressure, 12 by migration

• Estimates are representative of geologic capacity constraints nationwide
Storage Footprint for 100-year Injection
(Szulczewski, MacMinn, Herzog & Juanes, PNAS 2012)

- sedimentary basins
- sedimentary rocks more than 800m thick
- faults
- footprint of trapped CO$_2$
- array of injection wells
- storage capacity (Gt CO$_2$)
What Does This All Mean for Climate Change Mitigation?

• We adopt a simplified CO₂-production curve that resembles emissions scenarios

• Rates increase during deployment and then decrease during phase-out

• Cumulative storage increases quadratically with injection duration
Supply and Demand Determine CCS Lifetime

- Geologic capacity scales at most as $C \sim T^{1/2}$ ("supply curve")
- Cumulative injection scales as $I \sim T^2$ ("demand curve")

- Large-scale implementation of CCS is a geologically-viable climate-change mitigation option in the United States over the next century

(Szulczewski, MacMinn, Herzog & Juanes, *PNAS* 2012)
Summary of Results

• Storage capacity is dynamic, and depends on duration of injection: both \( \text{CO}_2 \) migration and pressure dissipation may limit storage capacity.

• Storage capacity in underground formations imposes a constraint, which is dependent on the CCS injection scenario:
  ‣ Cumulative injection scales as \( I \sim T^2 \) (“demand curve”)
  ‣ Geologic capacity scales at most as \( C \sim T^{1/2} \) (“supply curve”)

• The crossover of these two curves constrains the life span of CCS:
  ‣ In the case of the United States, this is in the range of 100-200 years
Carbon Capture and Storage (CCS)

- Can CCS be a bridge solution to a yet-to-be-determined low-carbon energy future?

**Lifetime of carbon capture and storage as a climate-change mitigation technology**

Michael L. Szulczewski\textsuperscript{a}, Christopher W. MacMinn\textsuperscript{b}, Howard J. Herzog\textsuperscript{c}, and Ruben Juanes\textsuperscript{a,d,1}

Departments of \textsuperscript{a}Civil and Environmental Engineering and \textsuperscript{b}Mechanical Engineering, \textsuperscript{c}Energy Initiative, and \textsuperscript{d}Center for Computational Engineering, Massachusetts Institute of Technology, Cambridge, MA 02139

Edited by M. Granger Morgan, Carnegie Mellon University, Pittsburgh, PA, and approved February 15, 2012 (received for review September 19, 2011)

- **CCS is a geologically-viable climate-change mitigation option in the United States over the next century** (Szulczewski et al., *PNAS* 2012)

**Earthquake triggering and large-scale geologic storage of carbon dioxide**

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Departments of \textsuperscript{a}Geophysics and \textsuperscript{b}Environmental Earth System Science, Stanford University, Stanford, CA 94305

Edited by Pamela A. Matson, Stanford University, Stanford, CA, and approved May 4, 2012 (received for review March 27, 2012)

- **CCS is a risky, and likely unsuccessful, strategy for significantly reducing greenhouse gas emissions** (Zoback and Gorelick, *PNAS* 2012)

- Is CO\textsubscript{2} leakage really a show-stopping risk?
No geologic evidence that seismicity causes CO\textsubscript{2} leakage through faults

- Zoback & Gorelick’s line of argument:
  - Maps of earthquakes epicenters show earthquakes occurring almost everywhere, suggesting Earth’s crust is near critical state
  - Overpressure from CO\textsubscript{2} injection will trigger earthquakes within the reservoir and the caprock
  - They take for granted that this will cause leakage through faults
Zoback and Gorelick articulate an important, albeit well-known, concern: CCS may induce seismicity, as can other subsurface technologies. However, their characterization misrepresents its relevance to CCS.

- The vast majority of earthquakes are much deeper than CO2 storage reservoirs.
- Sedimentary rocks can undergo substantial deformation without establishing leaking pathways, in contrast with brittle basement rocks.
- Link between fault slip and leakage is tenuous for sedimentary rocks: hydrocarbon reservoirs have existed for millions of years in regions of intense seismic activity (e.g., Southern California).
- While induced earthquakes and leakage risk could compromise particular CCS projects (they mention the Mountaineer project), many geologic formations exhibit excellent promise for storing CO2.

No geologic evidence that seismicity causes CO₂ leakage through faults
The debate is far from settled …

Letter

Juanes et al. (PNAS 2012)

No geologic evidence that seismicity causes fault leakage that would render large-scale carbon capture and storage unsuccessful

Letter

Zoback and Gorelick (PNAS 2012)

Reply to Juanes et al.: Evidence that earthquake triggering could render long-term carbon storage unsuccessful in many regions
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