Project DE-FE0002041: Modeling and Risk Assessment of CO_2 Sequestration at the Geologic-Basin Scale

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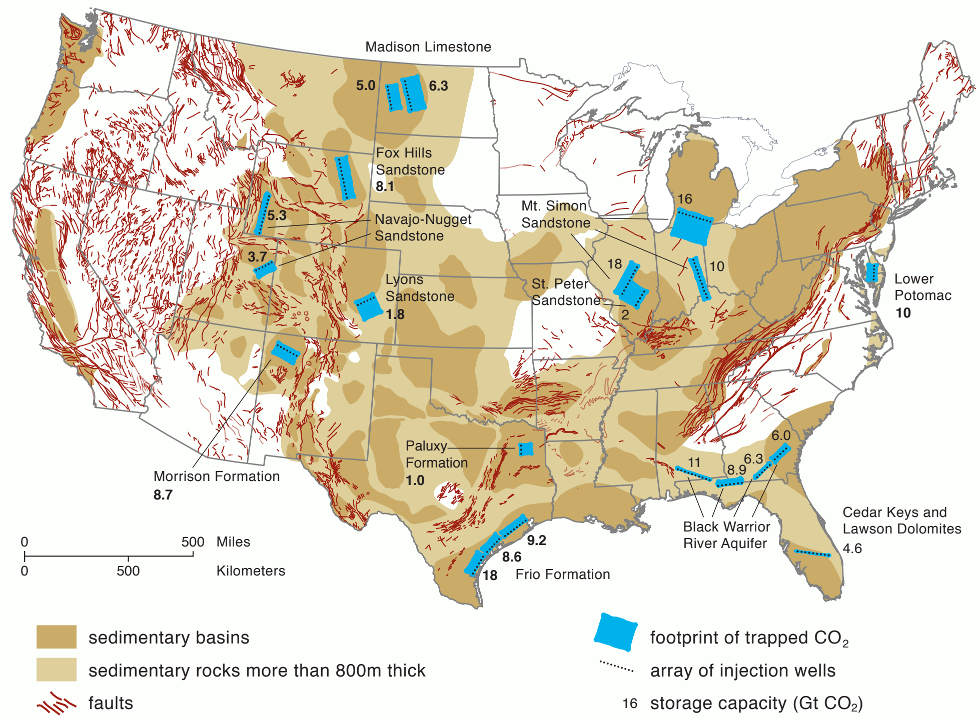


U.S. Department of Energy
National Energy Technology Laboratory
Carbon Storage R&D Project Review Meeting
August 21-23, 2012

Benefit to the Program

- Program goals being addressed
  - This project targets one of the key objectives of the Program's Core R&D element (*Simulation and Risk Assessment*)
  - Develop technologies that will support industries' ability to predict *CO_2 storage capacity* in geologic formations to within ±30 percent.
- Project benefits
  - a physically-based approach for estimating capacity and leakage risk at the basin scale
  - facilitate deployment of CCS by providing the basis for a simpler and more coherent regulatory structure than an "individual-point-of-injection" permitting approach
  - lead to better science-based policy for post-closure design and transfer of responsibility to the State

Project Overview: Goals and Objectives

- Main Objective: develop tools for better understanding, modeling and risk assessment of CO_2 permanence in geologic formations at the geologic basin scale
- Specific technical objectives
  - develop mathematical models of capacity and injectivity at the basin scale
  - apply quantitative risk assessment methodologies that will inform on CO_2 permanence
  - apply the models to geologic basins across the continental United States

Tasks – Overview

Task No.	Task Description	Task Duration	Task Funding
1	Project Management and Planning	12/01/2009 – 11/30/2012	$9968
2	Technology Status Assessment	12/01/2009 – 2/28/2010	$9968
3	Develop mathematical models of CO2 migration	12/01/2009 – 11/30/2011	$119618
4	Apply models to basins in the continental U.S.	6/01/2011 – 11/30/2012	$43195
5	Estimate CO2 storage capacity and injectivity	6/01/2011 – 11/30/2012	$43195
6	Develop and apply risk assessment methodologies	12/01/2010 – 11/30/2012	$89714
7	Integrate CCS research in the classroom	12/01/2009 – 11/30/2012	$43195

Project Schedule

Task	Subtask	Year 1				Year 2				Year 3			
1	1.0	1,2											
2	2.0	3											
3	3.1												
	3.2				5								
	3.3												
	3.4								6,7,8				
4	4.1								9		10		
	4.2												11
5	5.1												
	5.2												12
6	6.1												
	6.2												
	6.3												
	6.4												13,15
7	7.0		4	14				14				14	

Project Milestones

Milestone	Planned Completion Date	Actual Completion Date
1. Revise Project Management and Plan	1/31/2010	1/31/2010
2. Project kick-off meeting	3/30/2010	3/30/2010
3. Technology Status Assessment	3/30/2010	3/30/2010
4. Educational program instituted	6/30/2010	6/30/2010
5. Mathematical models of pressure evolution and capillary trapping	12/31/2010	12/31/2010

Project Milestones

(cont'd)

Milestone	Planned Completion Date	Actual Completion Date
6. Mathematical models of dissolution and caprock leakage	12/31/2011	12/31/2011
7. Software tool to estimate storage capacity	12/31/2011	12/31/2011
8. Tool for visualization of CO2 footprints in Google Earth	12/31/2011	
9. Synthesis of geologic and hydrogeologic data of U.S. basins	12/31/2011	12/31/2011
10. Application of migration mathematical models to U.S. basins	12/31/2011	12/31/2011

Project Milestones

(concl'd)

Milestone	Planned Completion Date	Actual Completion Date
11. Application of leakage mathematical models to U.S. basins	11/30/2012	
12. Capacity and injectivity estimates from dynamic models	11/30/2012	
13. Development and application of risk assessment methodology	11/30/2012	
14. Deliver CCS short course	7/31/2010 (every year)	7/31/2010 (every year)
15. Final project synthesis and report	11/30/2012	

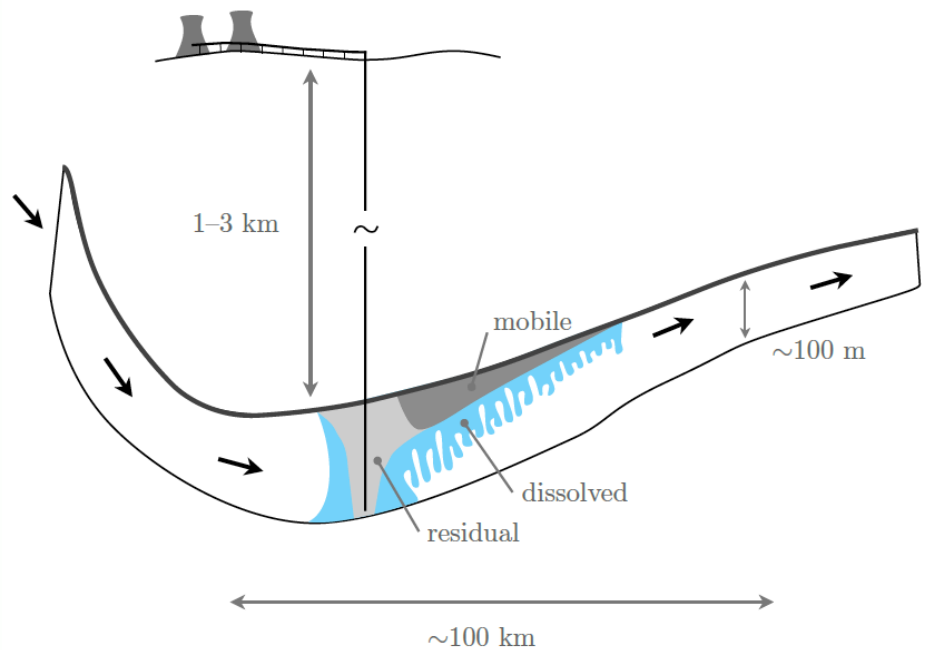
Accomplishments to Date

- Developed mathematical model of CO2 migration with capillary trapping and solubility trapping from convective mixing on sloping aquifers with regional groundwater flow
- Developed mathematical models of overpressure from CO2 injection in deep saline formations
- Developed new methodology for basin-specific storage capacity estimates that incorporate both constraints: CO2 migration and pressure evolution
- Applied the new methodology to a selection of saline aquifers across the United States to determine the dynamic storage capacity and the lifetime of CCS as a climate-change mitigation technology
- Published four journal papers (TIPM, JFM, PNAS), five peer-reviewed conference papers (GHGT, CMWR), and over twenty conference presentations

Summary of Results

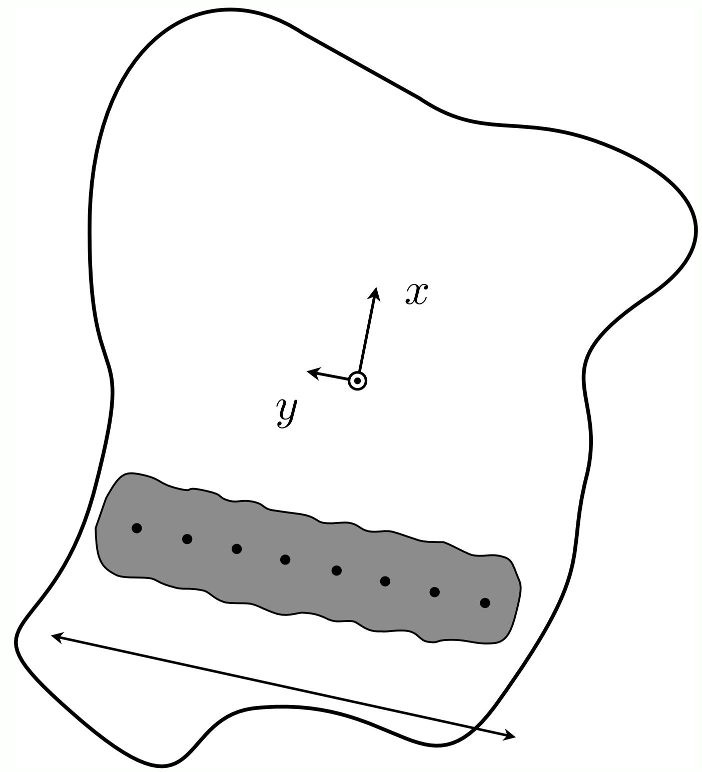
- Storage capacity is dynamic, and depends on duration of injection: both CO_2 migration and pressure dissipation may limit storage capacity
- Storage capacity in underground formations imposes a constraint, which is dependent on the CCS injection scenario
  - Cumulative injection scales as $I \sim T^2$ ("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 100-300 years

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

  $U_n < 1\,\mathrm{m/year}$



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 CO_2 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." (Ehligh-Economides and Economides, *JPSE* 2010)
- "CCS can never work, US study says" (Canada Free Press on Ehlig-Economides and Economides, 2010)

Journal of Petroleum Science and Engineering 70 (2010) 123–130

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Sequestering carbon dioxide in a closed underground volume

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[b] Department of Chemical Engineering, University of Houston, Houston, Texas 77204, USA

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 Preceedings*, 2010)

Traditional Approach

The volumetric equation for CO_2 resource calculation in saline formations with consistent units assumed is as follows:

$$G_{CO2} = A_t \, h_g \, \phi_{tot} \, \rho \, E$$

Parameter	Units*	Description
G_{CO2}	M	Mass estimate of saline formation CO_2 resource.
A_t	L^2	Geographical area that defines the basin or region being assessed for CO_2 storage calculation.
h_g	L	Gross thickness of saline formations for which CO_2 storage is assessed within the basin or region defined by A.
ϕ_{tot}	L^3/L^3	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.
ρ	M/L^3	Density of CO_2 evaluated at pressure and temperature that represents storage conditions anticipated for a specific geologic unit averaged over h_g.
E**	L^3/L^3	CO_2 storage efficiency factor that reflects a fraction of the total pore volume that is filled by CO_2.

* 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

    $$M_{\mathrm{CO2,strat}} = \rho_{\mathrm{CO2}} V_{\mathrm{trap}} \phi (1 - S_{wi}) C_c$$

  - Residual-gas traps

    $$M_{\mathrm{CO2,resid}} = \rho_{\mathrm{CO2}} V_{\mathrm{sweep}} \phi S_{gr}$$

  - Solubility traps

    $$M_{\mathrm{CO2,solub}} = V_{\mathrm{aquifer}} \phi \rho_w X_{\mathrm{CO2}} C_s$$

  - Mineral traps
    - Highly uncertain and time-dependent

Traditional Approach

- Splitting the sources of trapping capacity

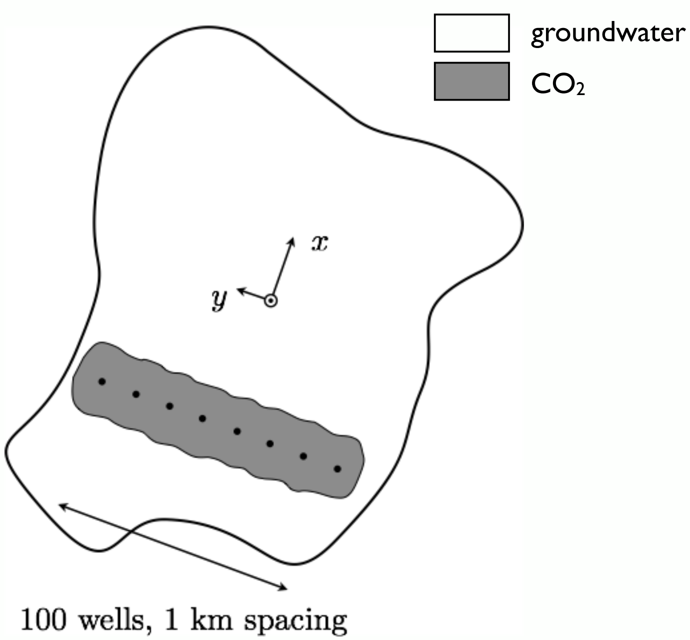
"estimation of the CO_2 storage capacity through residual-gas trapping can be achieved only in local- and site-scale assessments, but not in basin- and regional-scale assessments." (Bachu et al., *IJGHGC* 2007)

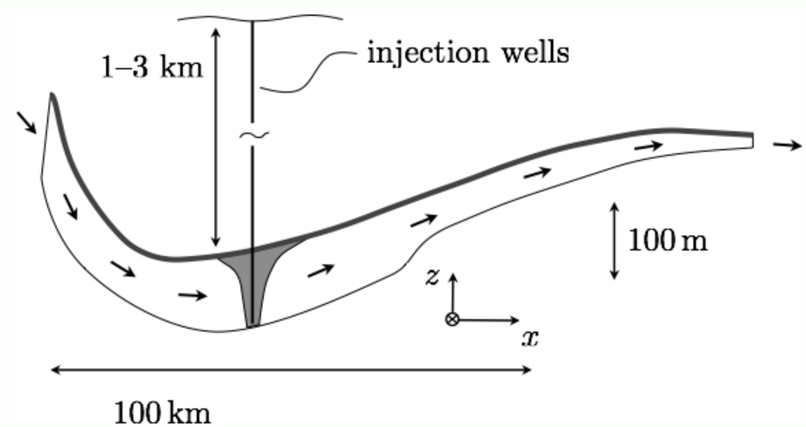
- Here we will show how to obtain basin-scale storage capacities that include residual and solubility trapping

Migration Model

The geologic setting of our migration model has two key features:

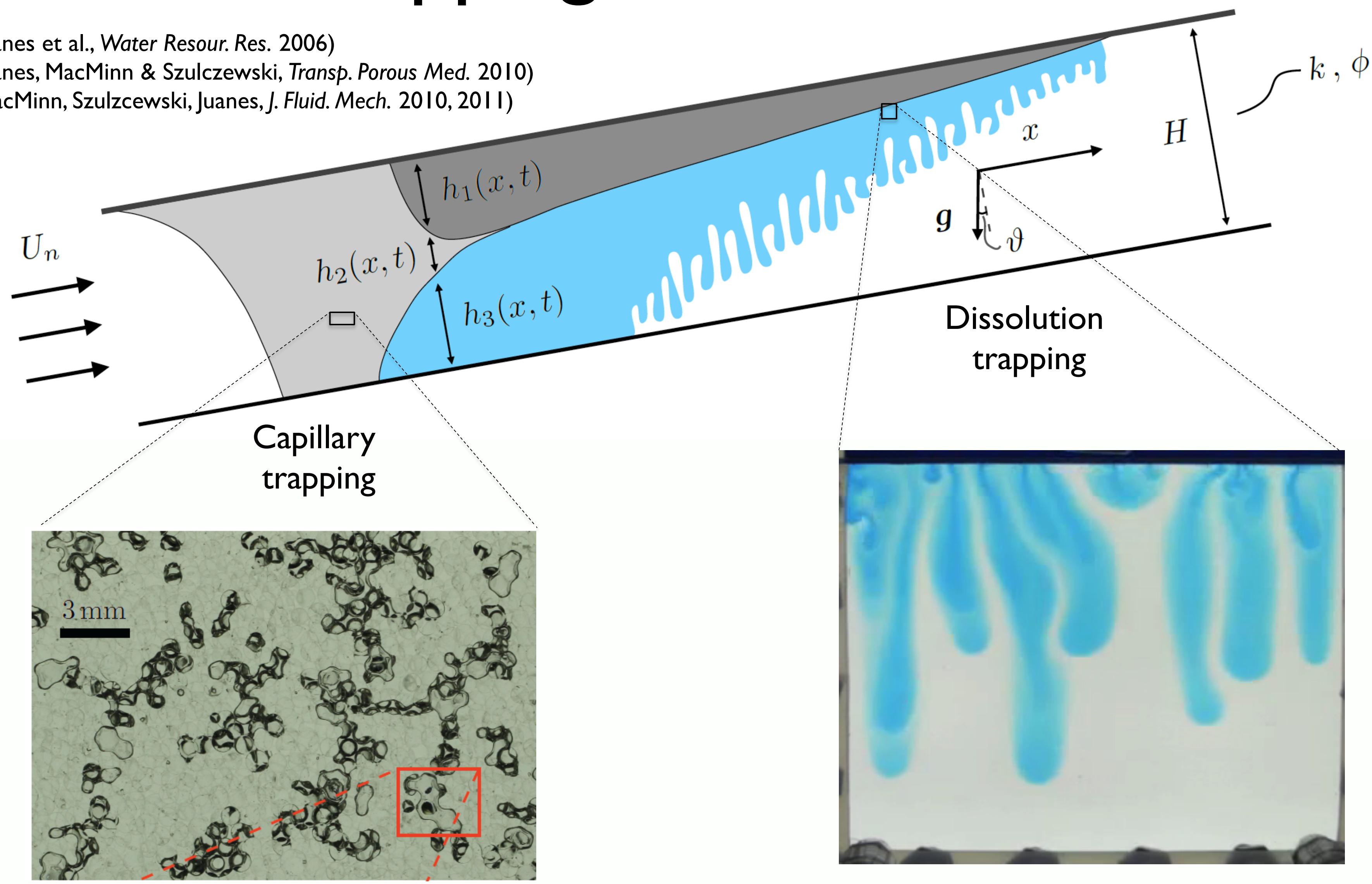
- basin scale
- line-drive array of wells





Trapping Mechanisms

(Juanes et al., *Water Resour. Res.* 2006)
(Juanes, MacMinn & Szulczewski, *Transp. Porous Med.* 2010)
(MacMinn, Szulczewski, Juanes, *J. Fluid. Mech.* 2010, 2011)



Modeling Approximations

Fluid

- sharp interfaces
- negligible capillary forces
- negligible fluid compressibility

Aquifer

- thin aspect ratio (vertical flow equilibrium / "Dupuit Approx.")
- homogeneous properties
- negligible rock compressibility

Bear
Elsevier 1972

Barenblatt *et al.*
Nedra 1972

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

Hesse *et al.*
SPE 2006

Hesse *et al.*
JFM 2008

Nordbotten & Celia
JFM 2006

Juanes *et al.*
TiPM 2010

MacMinn *et al.*
JFM 2010

Migration without Dissolution

Advective Effects — Diffusive Effects

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

capillary trapping — g.w. flow — up-slope migration — spreading

$$\widetilde{\mathcal{R}} = \begin{cases} 1 & \partial\eta/\partial\tau > 0 \\ 1-\Gamma & \partial\eta/\partial\tau < 0 \end{cases}$$

$$f = \frac{\mathcal{M}\eta}{(\mathcal{M}-1)\eta+1} \qquad \mathcal{M} = \frac{\lambda_g}{\lambda_w}$$

$$\Gamma = \frac{S_{gr}}{1-S_{wc}}$$

Scaling $\left\{ \quad \eta = \dfrac{h}{H} \qquad \tau = \dfrac{t}{T_c} \qquad \xi = \dfrac{x}{L_c} \right.$

$$N_f = 1 \qquad N_s = \frac{\Delta\rho g k\lambda_g}{U_n}\sin\vartheta$$

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

$$T_c = \frac{Q_i T_i/2}{U_n H} \qquad L_c = \frac{Q_i T_i}{2H(1-S_{wc})\phi}$$

Migration without Dissolution

Advective Effects

Diffusive Effects

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

g.w. flow

up-slope migration

spreading

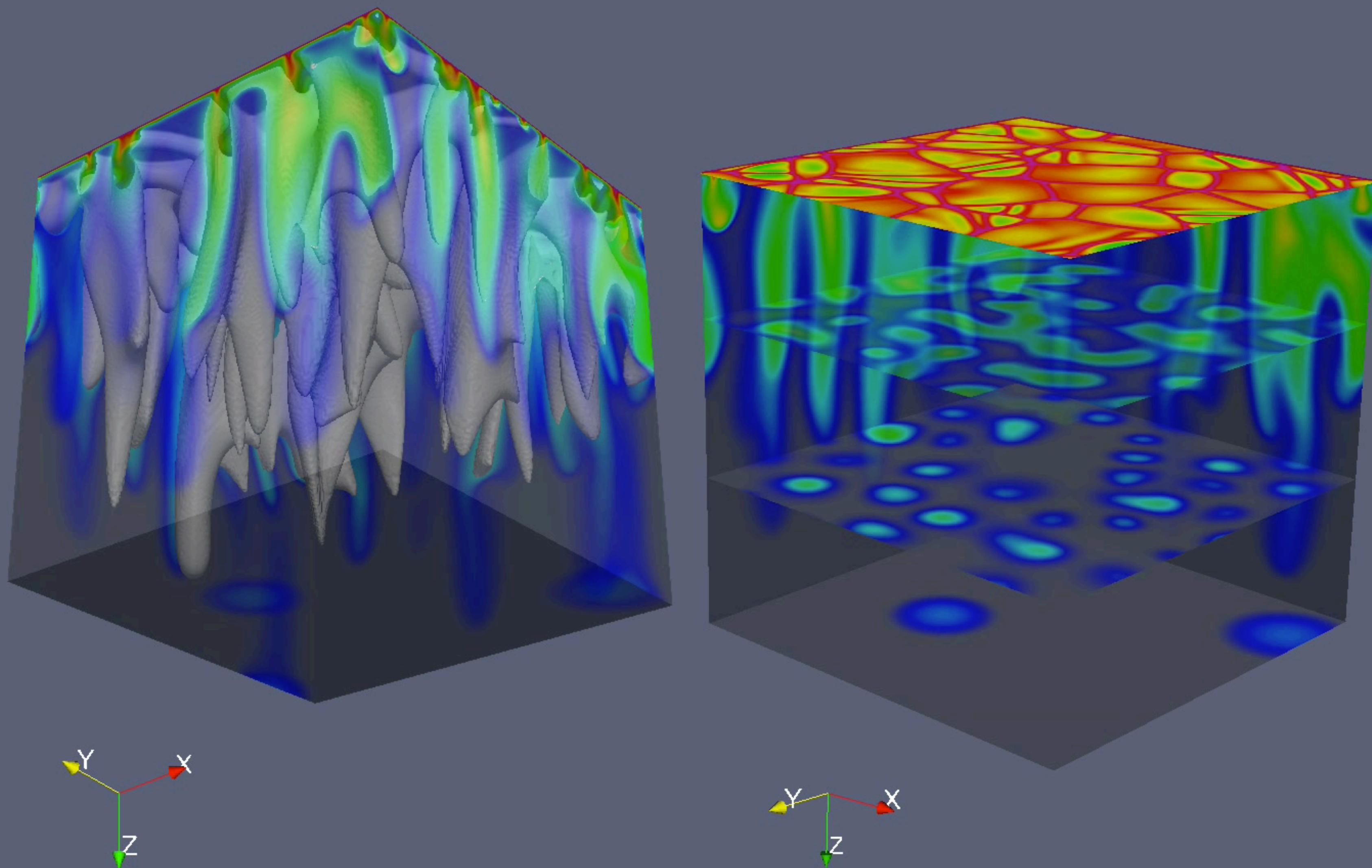
- Complete analytical solution
- Interaction between flow and slope

Juanes & MacMinn
SPE 2008

Juanes *et al.*
TiPM 2010

MacMinn *et al.*
JFM 2010

Dissolution by Convective Mixing



Migration with Dissolution

Advective Effects | Diffusive Effects | Sink

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

capillary trapping | g.w. flow | up-slope migration | buoyant spreading | dissolution

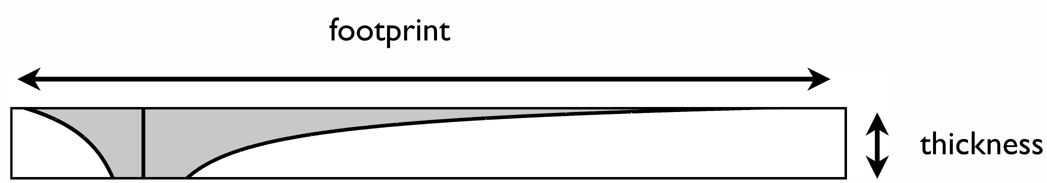
Essential features:

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

Efficiency Factor

- Macroscopic measure of storage efficiency
  - How much aquifer is "used" per unit CO_2 stored?

$$\varepsilon = \frac{\text{volume of CO}_2}{\text{volume of aquifer}} = \frac{2}{\xi_T}$$



Bachu *et al.*
Int. J. GHGC 2007

★ How does this depend on $\mathcal{M}$, Γ , N_s/N_f ?

Efficiency Factor

Transp Porous Med (2010) 82:19–30
DOI 10.1007/s11242-009-9420-3

The Footprint of the CO_2 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

Analytical Solutions with Dissolution

J. Fluid Mech. (2010), *vol.* 662, *pp.* 329–351.

doi:10.1017/S0022112010003319

CO_2 migration in saline aquifers. Part 1. Capillary trapping under slope and groundwater flow

C. W. MACMINN[1], M. L. SZULCZEWSKI[2] AND R. JUANES[2]†

J. Fluid Mech. (2011), *vol.* 688, *pp.* 321–351.

doi:10.1017/jfm.2011.379

CO_2 migration in saline aquifers. Part 2. Capillary and solubility trapping

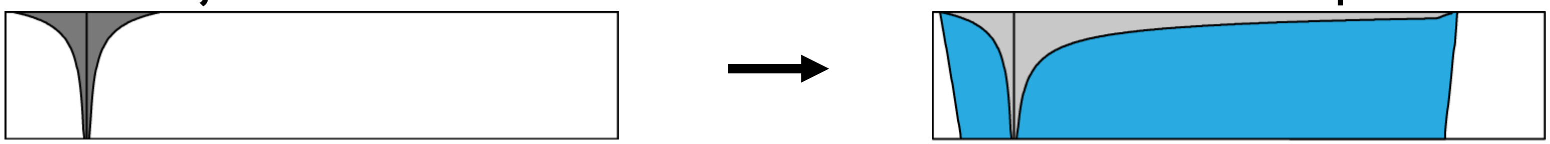
C. W. MacMinn[1], M. L. Szulczewski[2] and R. Juanes[2]†

Migration Storage Capacity

We estimate aquifer capacity by using the model in reverse

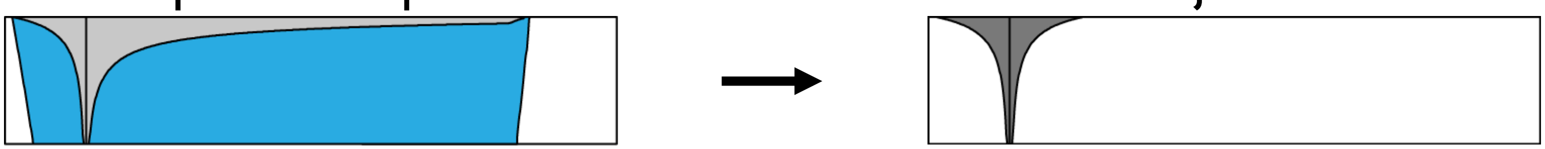
Forward

Set injection volume → Calculate footprint



Reverse

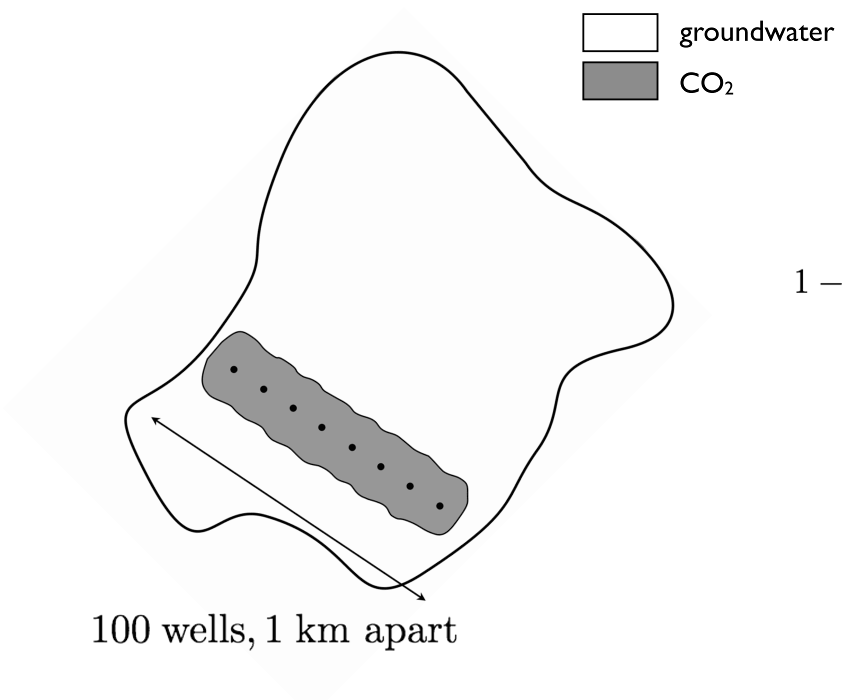
Set footprint to aquifer size → Calculate injection volume

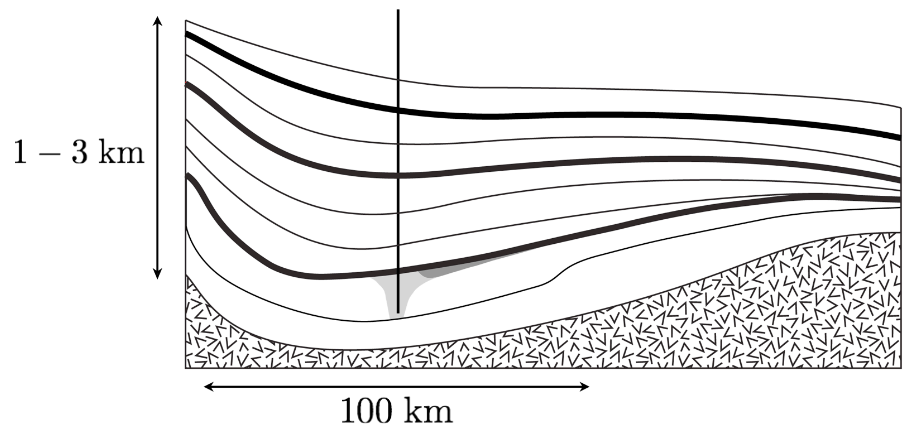


Pressure Model

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

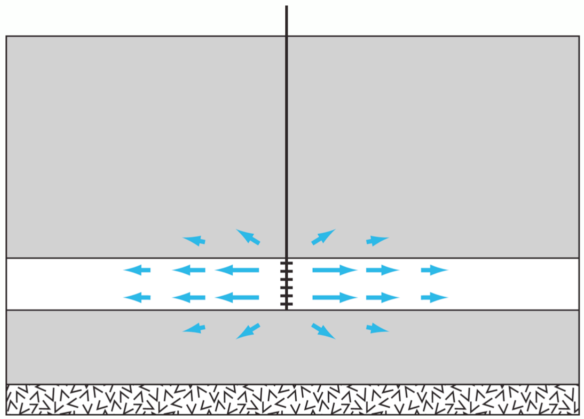
- basin scale
- line-drive array of wells
- multiple layers



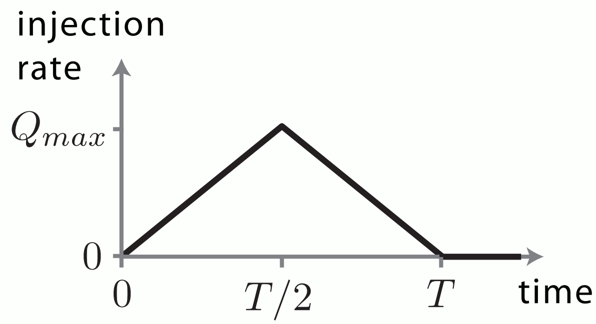


Model Features

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

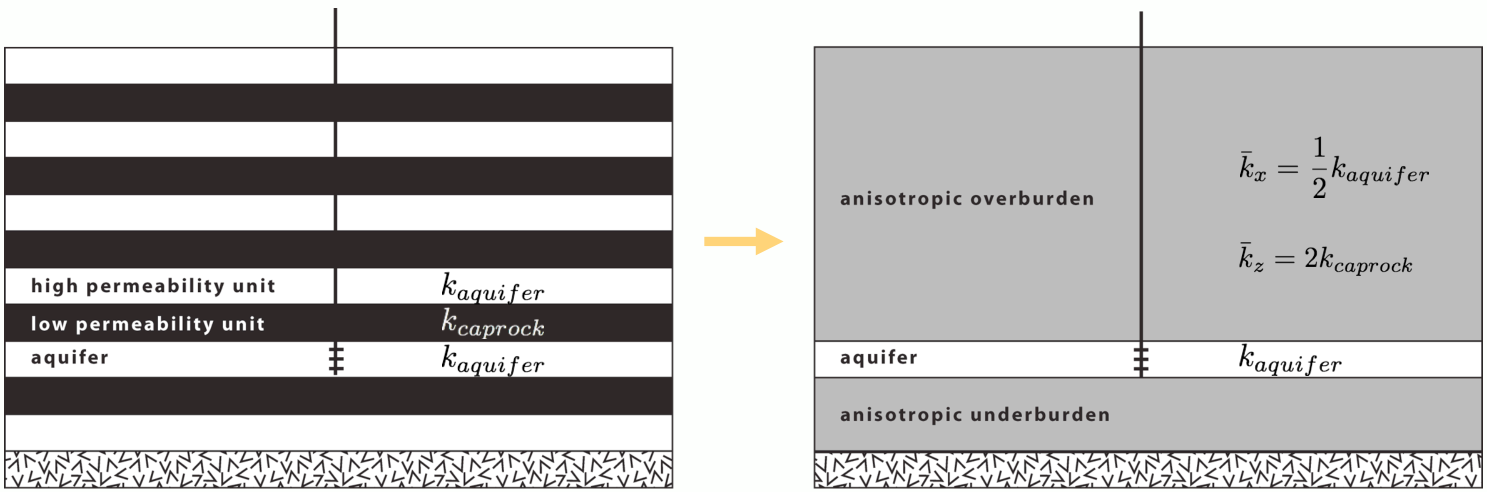


- Vertical pressure dissipation
  - major contributor to pressure dissipation
- Ramp-up, ramp-down injection scenario



Vertical Pressure Dissipation

We model the overburden and underburden with average, anisotropic permeabilities

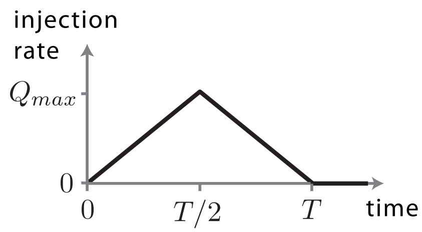


Pressure Storage Capacity

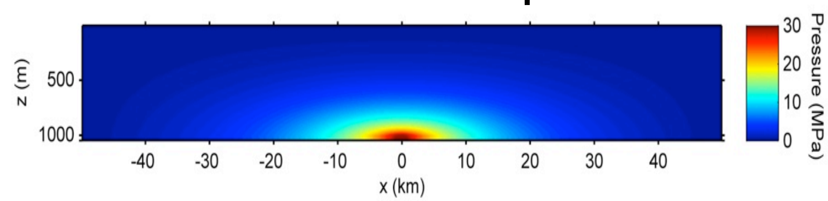
We estimate pressure-limited capacity by using the model in reverse

<u>Forward</u>

set injection scenario

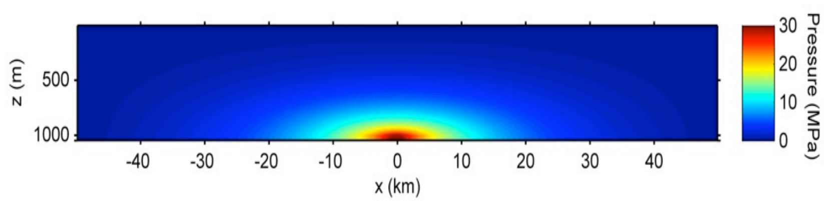


calculate maximum pressure

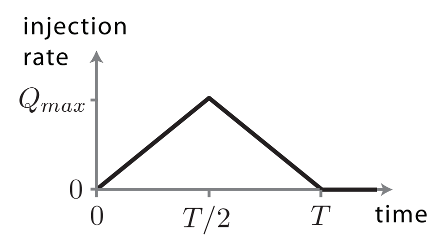


<u>Reverse</u>

set maximum pressure
to fracture pressure

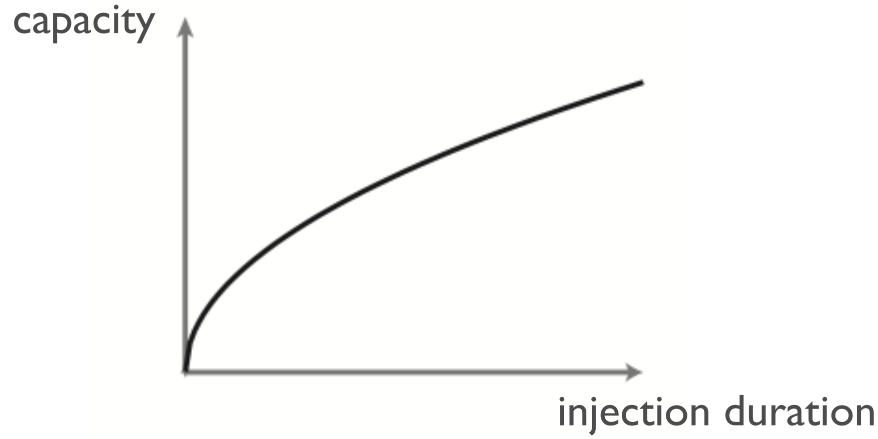


calculate injection scenario
and volume



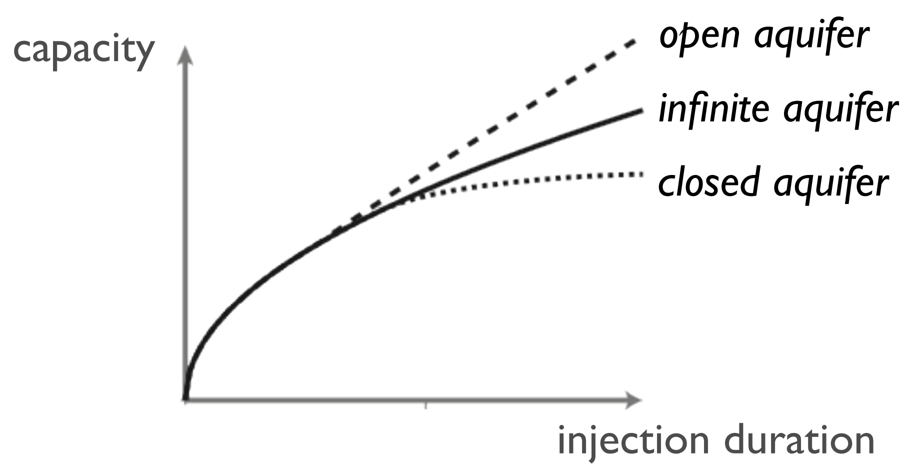
Pressure Storage Capacity

- 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 $\sqrt{T}$

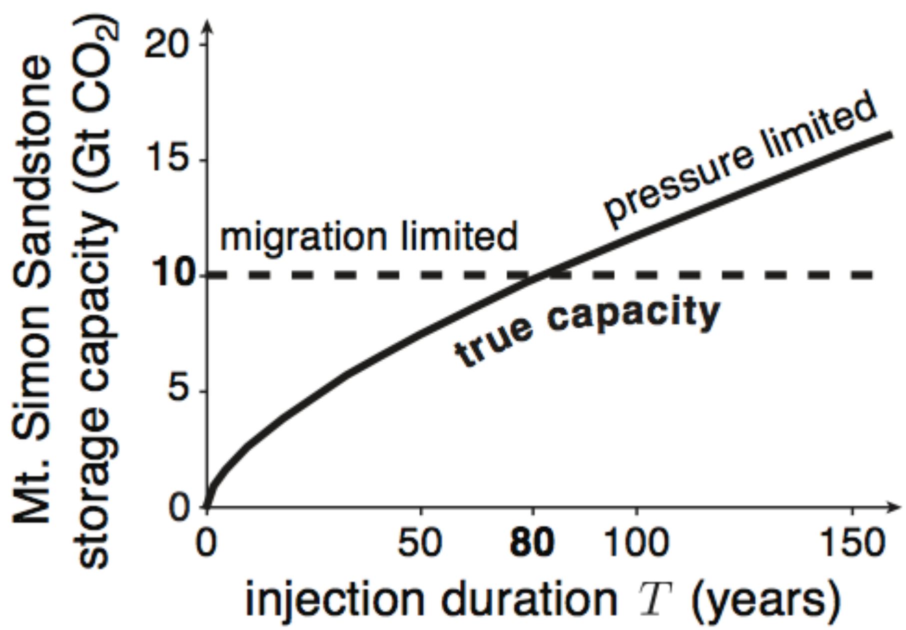


Capacity Estimates from Fluid Dynamics

Szulczewski and Juanes
(*GHGT* 2010)

Storage capacity is dynamic

- For short durations of injection, overpressure is more limiting
- For long durations of injection, CO_2 migration is more limiting

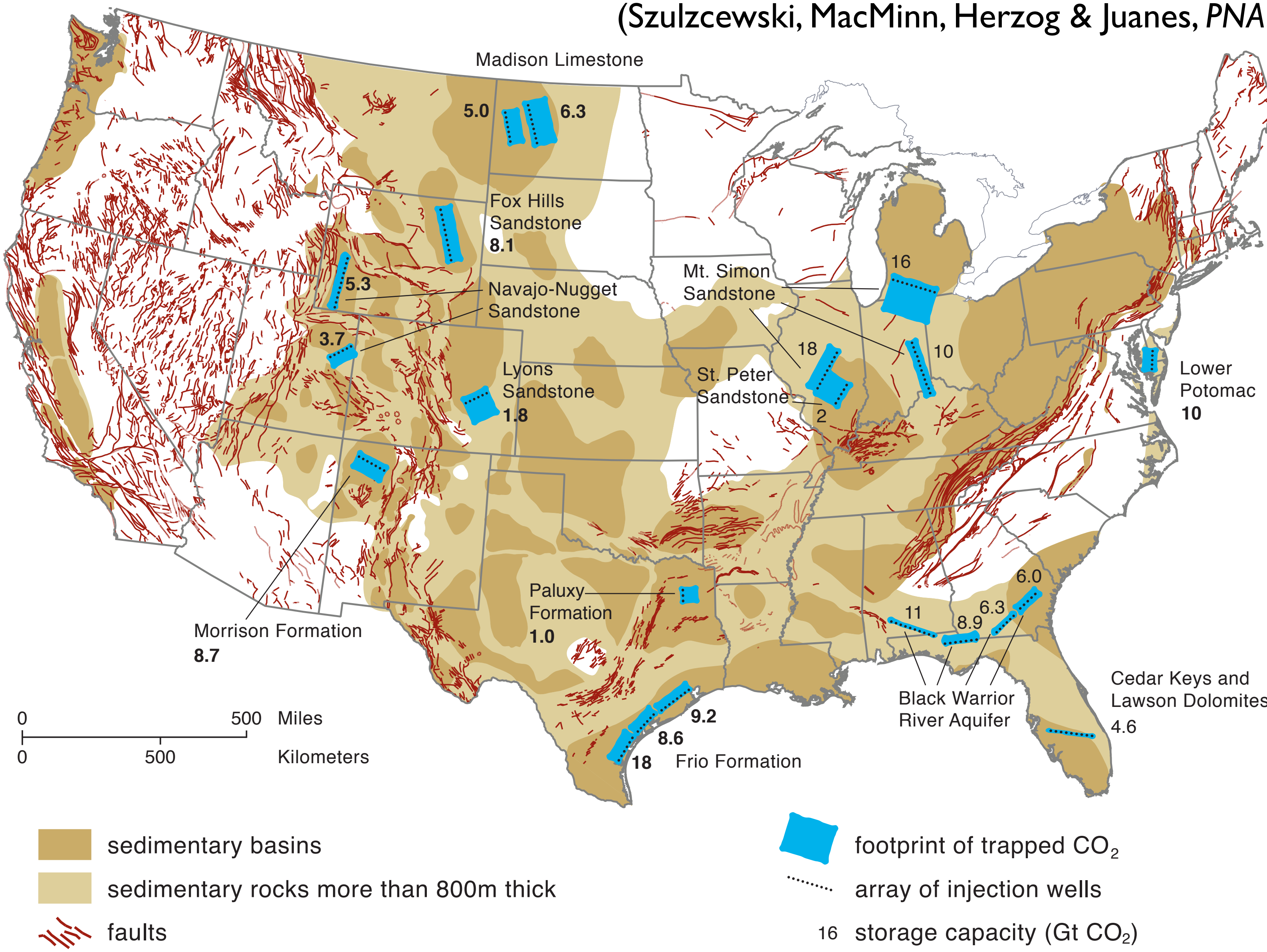


Capacity Estimates for the United States

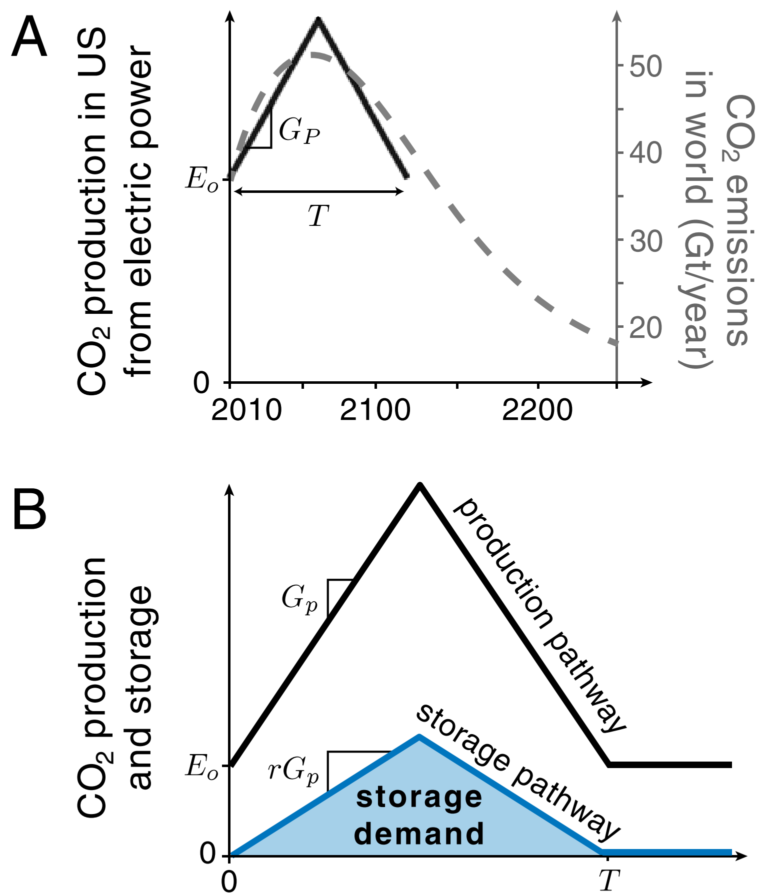
- Studied 20 well arrays in 12 saline aquifers throughout the U.S.
  - Largest, most structurally sound, best characterized aquifers
  - Capacities between 1 and 18 $GtCO_2$
- 8 were limited by pressure, 12 by migration
- Estimates are representative of geologic capacity constraints nationwide

Storage Footprint for 100-year Injection

(Szulzcewski, MacMinn, Herzog & Juanes, *PNAS* 2012)



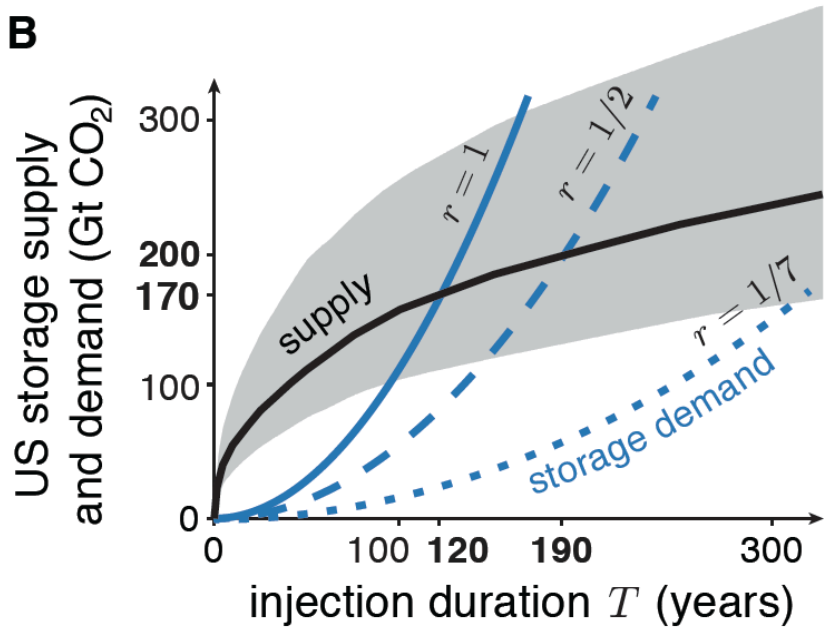
What Does This All Mean for Climate Change Mitigation?



- We adopt a simplified CO_2-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")



(Szulzcewski, MacMinn, Herzog & Juanes, *PNAS* 2012)

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

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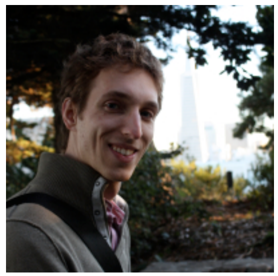
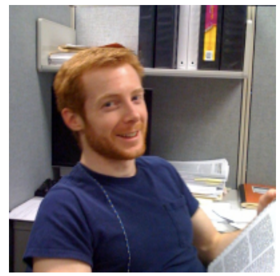
Acknowledgments

- Students



Chris MacMinn



Mike Szulczewski

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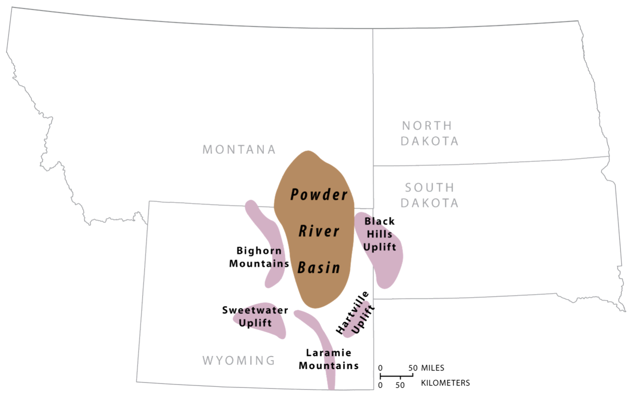
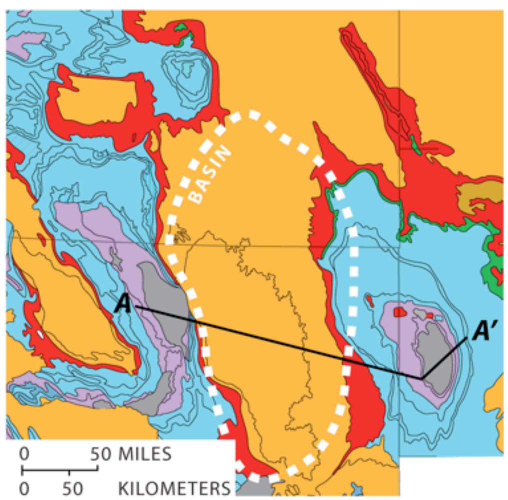
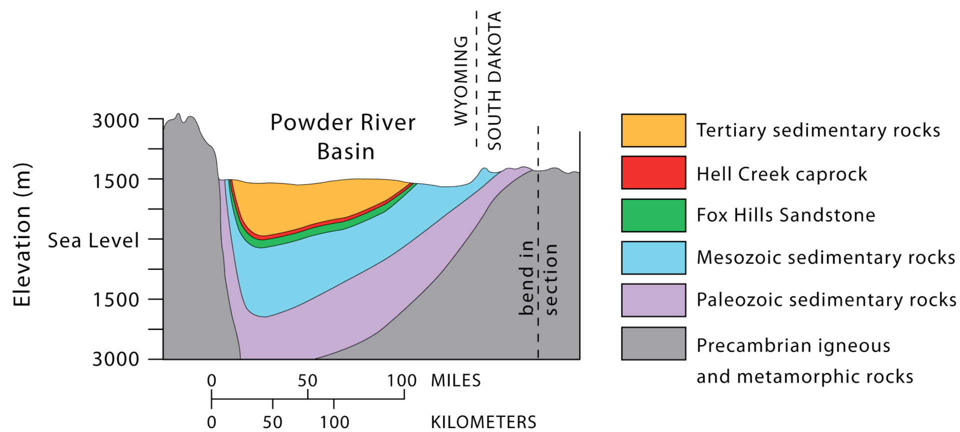
- Funding
  - U.S. DOE, MIT Energy Initiative, ARCO Chair, Reed Research Fund

Back-up slides

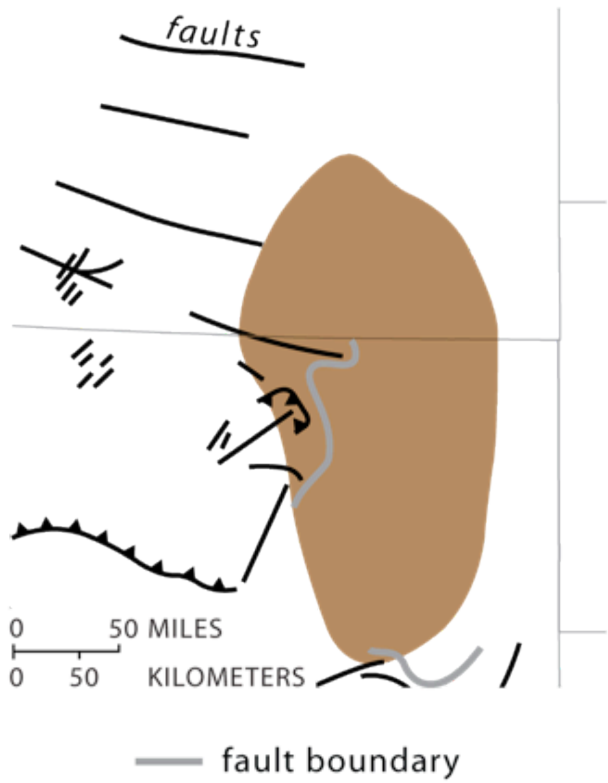
Application to the Fox Hills Sandstone



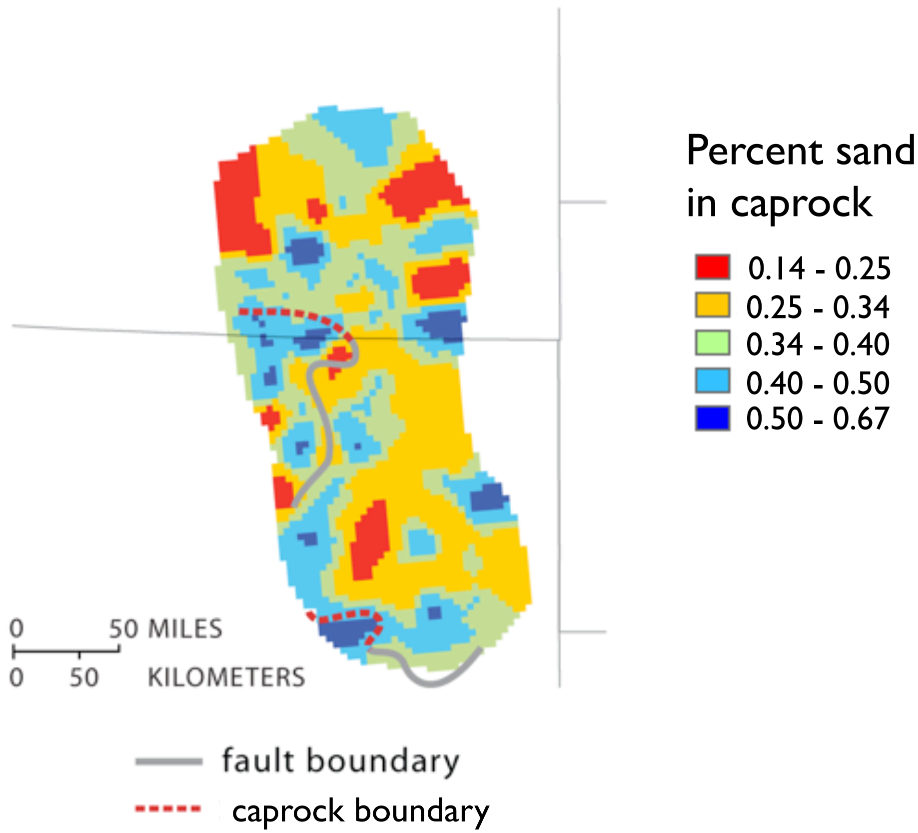




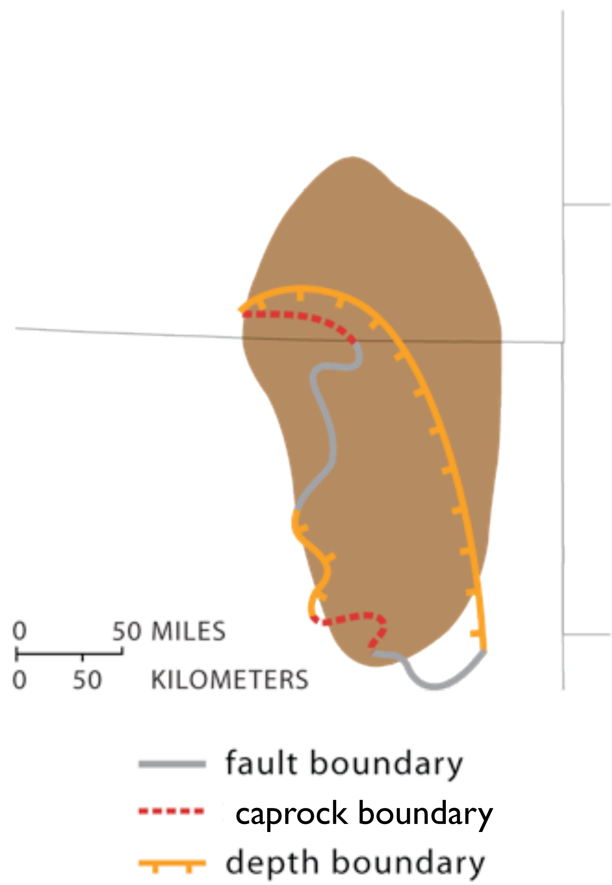
We inject where there are few or no faults



We inject where the caprock is sound



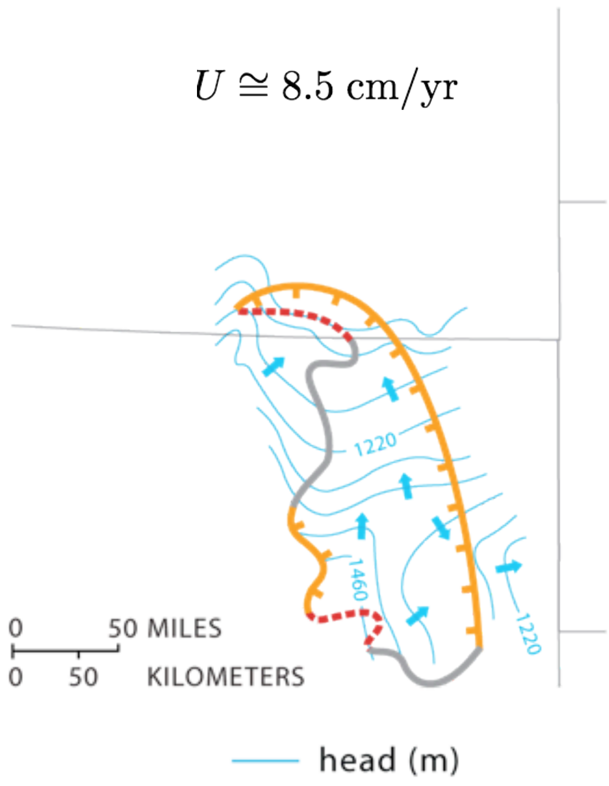
We inject where aquifer is > 800m deep



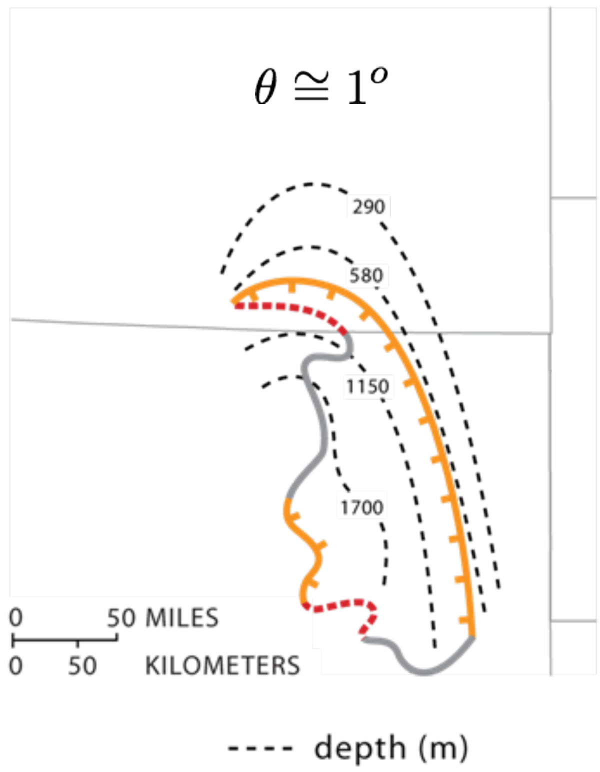
We neglect groundwater flow since slope is more important:

$$N_s/N_f = 21$$

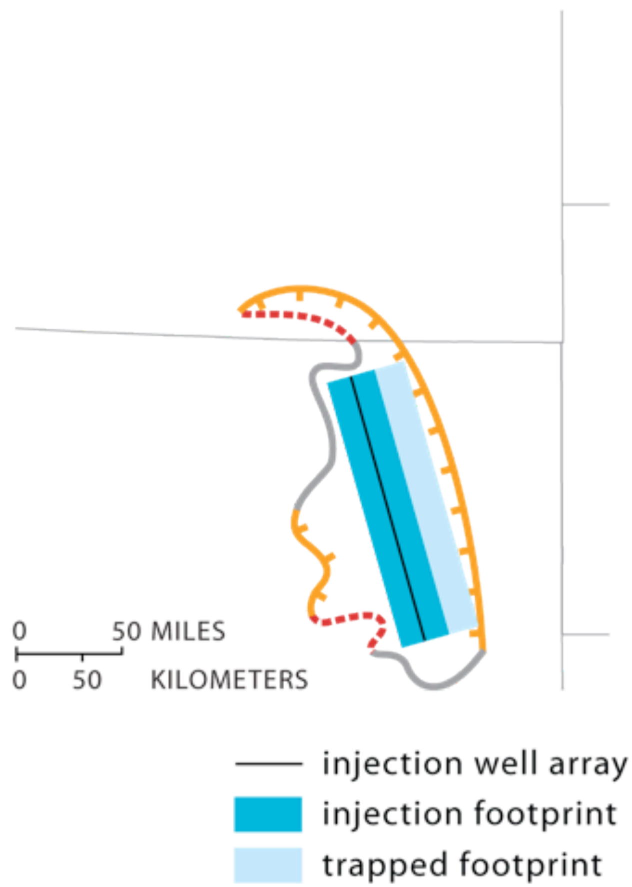
$U \cong 8.5$ cm/yr



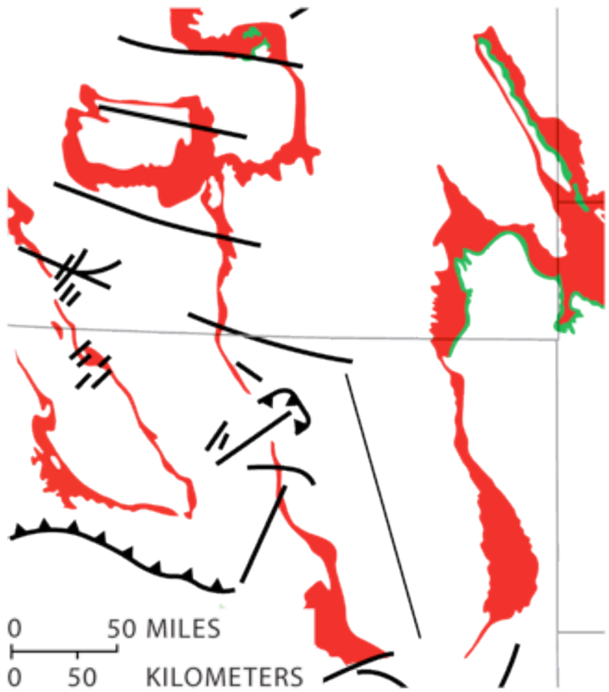
$\theta \cong 1^o$



We calculate a migration-based capacity of 8 Gt CO_2



Outcrops are taken as constant-pressure boundaries



injection well array
faults
caprock outcrop
aquifer outcrop

The pressure-limited capacity rises with injection time as expected

- The actual capacity is the lower capacity
- For small injection times, the pressure capacity is more limiting
- For long injection times, the migration-based capacity is more limiting