Basinwide Implications of Large CO_2 Injected Volumes into Deep Saline Formations

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ABSTRACT

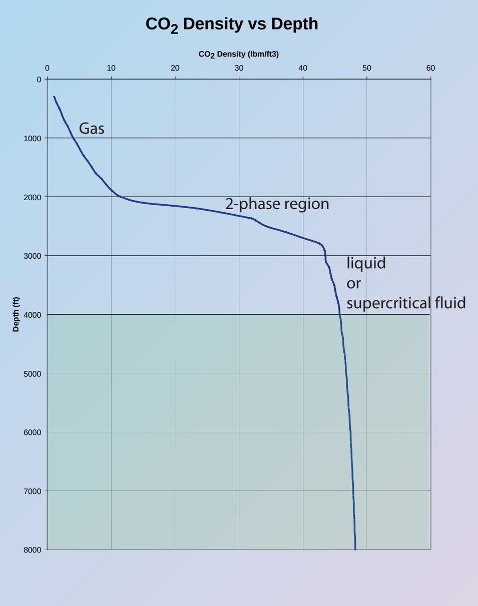
The deep saline formations represent the largest component in the portfolio of geologic storage capacity for sequestered CO_2. Most studies are concerned with breaching the caprock, formation capacity and injectivity, and CO_2, water and host/seal rock interaction. Less has been done to understand the effects of displacing the water out of the deeper basin into shallower outcrops, subcrops, or into freshwater regions of the same formation.

Injection is not purely displacement due to the dissolution of CO_2 into water; i.e., a unit volume of CO_2 does not necessarily displace a unit volume of water. The dissolution of CO_2 into water is a function of pressure, temperature, and water composition. Depending on the dissolution time and CO_2 solubility of the water, only a fraction of the water is displaced. The outer perimeter of the basin is extremely large compared to a single well injection site or a sequestration well field; therefore, the change in position of a freshwater/saline water interface is likely very small. Density of CO_2 saturated water and native water can be used to distinguish the direction of gravity flow, which under certain conditions may counter viscous flow. Likewise the natural, regional flow of the saline formations may influence CO_2 movement.

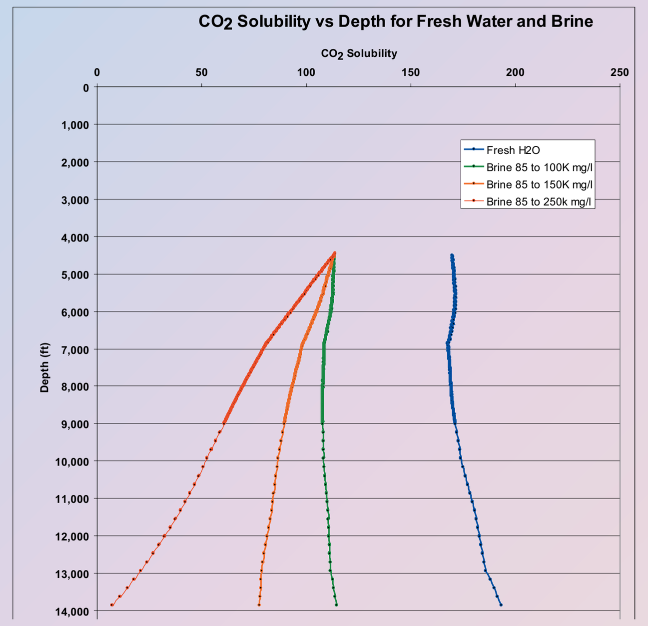
Analytical estimations using pressure transient analysis indicates small pressure (< 1 psi) changes occur 30-40 miles away from a single well after 30 years of injecting 1 Mtonne/year. Simple volumetric models and numerical simulation reservoir models provide scenarios of sequestration and water displacement from a deep saline formation.

Relevance of PVT (Fluid) Properties to Storage Capacity Calculations

Illinois Basin Saline Storage Greater than 4000 feet



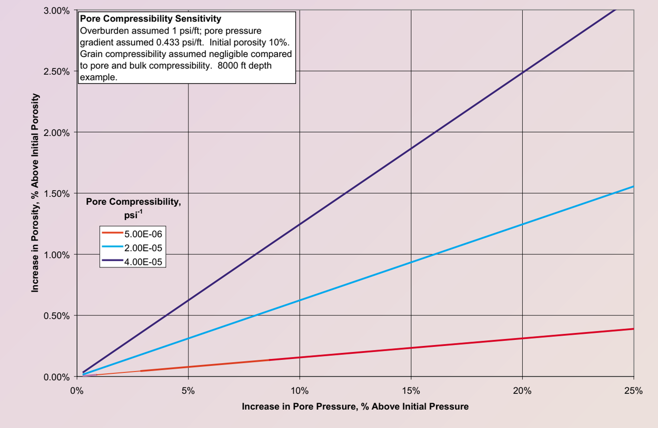
Temperature decreases density; pressure increases density. Increasing pressure and temperature with depth has compensating effects on CO_2 density. Pressure-Temperature effect on density is nearly linear and approximately constant from 4000-8000 feet (45.7 - 48.2 lbm/ft³)

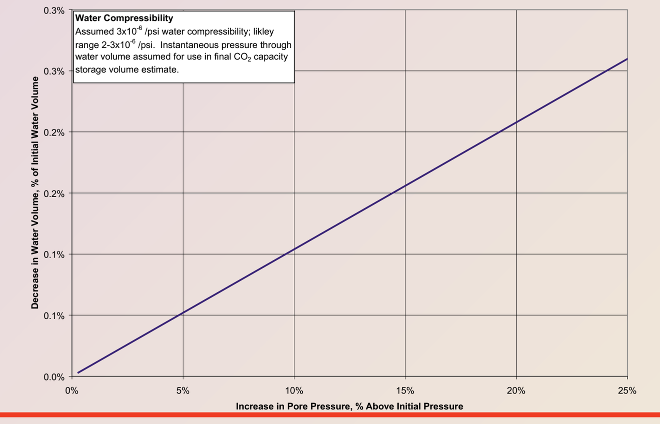


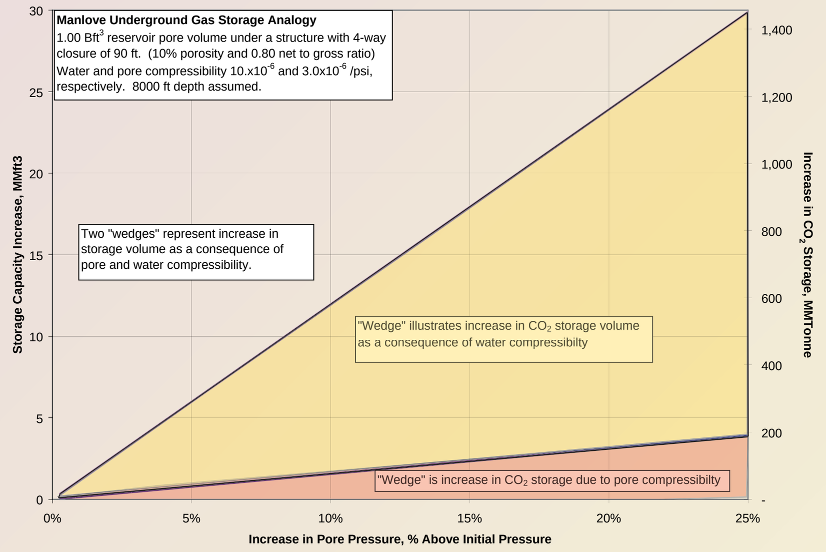
Manlove Gas Storage Project: 85,000 ppm@4500 feet. Linear salinity gradient assumed between 4500 feet and 10,000 feet. Salinity gradient greater than 2.31 ppm/feet decreases solubility with depth. CO_2 storage capacity may decrease with depth depending on the pressure, temperature, and salinity gradients.

Assumed pressure and temperature gradients of 0.433 psi/ft and 1 degree F /100 feet.

Additional Storage Capacity from Pore Volume and Water Compressibility — Closed System

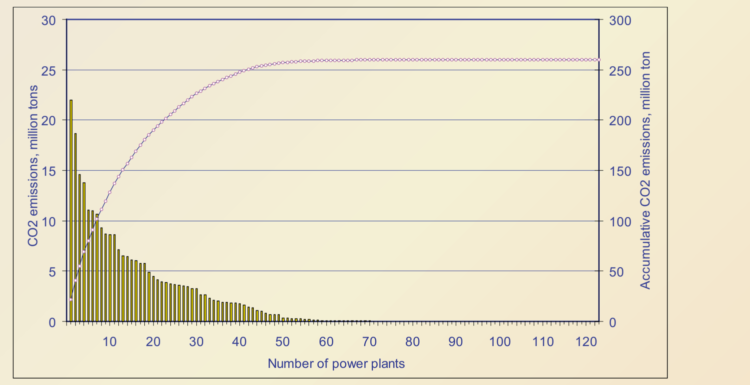






Pore space available for CO_2 storage increases due to pore, bulk volume and water compresibility. Pore and bulk volume increases with increasing pore pressure; water volume decreases with increasing pore pressure

Perspective: Requirements for Transporting 10 Mtonnes



Pipeline Example for 10 Mtonne/yr (188.5 Bscf/yr or 516.1 MMscf/d) with inlet pressure of 2500 psi (emissions source) and 1500 psi outlet (wellhead) to maintain supercritical (or dense phase) CO2 over the 200 mile length of horizontal pipeline. Booster station required if pressure drops below 1500 psia over the 200 mile length prior to reaching the wellhead.

Pipeline Options	Booster Station requirement
1- 22" line	None
1- 20" line	1-300 psi station
1-20" line and 1-10.75" line	None
1-18" line	2-600 psi stations
1-18" line and 1-16" line	None

West Texas CO2 pipeline infrastructure transports about 1.5 Bscf/d to West Texas for CO2 EOR. This example is 1/3 of the West Texas CO2 daily transportation rate.

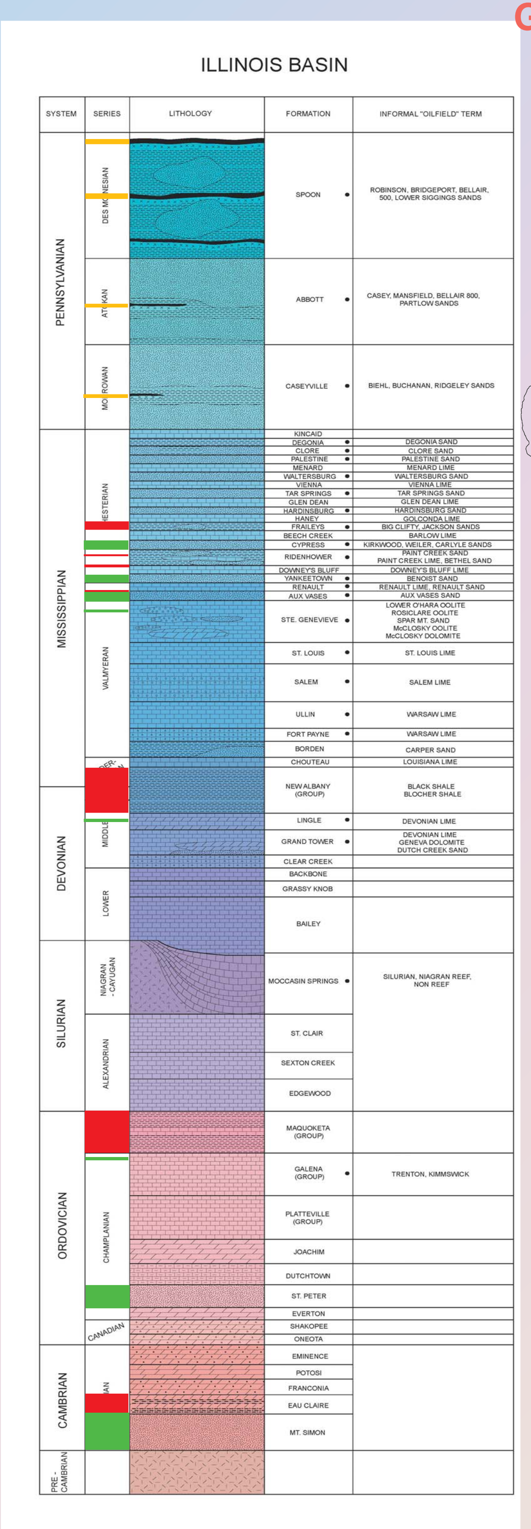
Comparison to West Texas CO_2 EOR Transporta-

Pipeline Name	Diameter (in)	Length (miles)	rate (Bcf/D)	Rate (Mtonne/D)
Cortez	30	502	1	0.05305
McElmo Creek	8	40	0.06	0.00318
Bravo	20	218	0.382	0.02026
Sheep Mountain	20	184	0.33	0.01750
Sheep Mountain	24	330	0.448	0.02376
Central Basin	16-26		0.6	0.03183
Este	12-14	119	0.25	0.01326
Trinity	12-8	53	0	0.00530
CRC	140	16	0.24	0.01273

Vertically Stacked Reservoirs

Pennsylvanian Coal Beds
The coal beds in the Illinois Basin are continuous across large areas of the basin. These beds are currently an active exploration target for coal bed methane.

Mississippian Age Oil Reservoirs
The Mississippian age oil reservoirs are the most prolific oil reservoirs within the basin and contribute 80% of the states oil production.

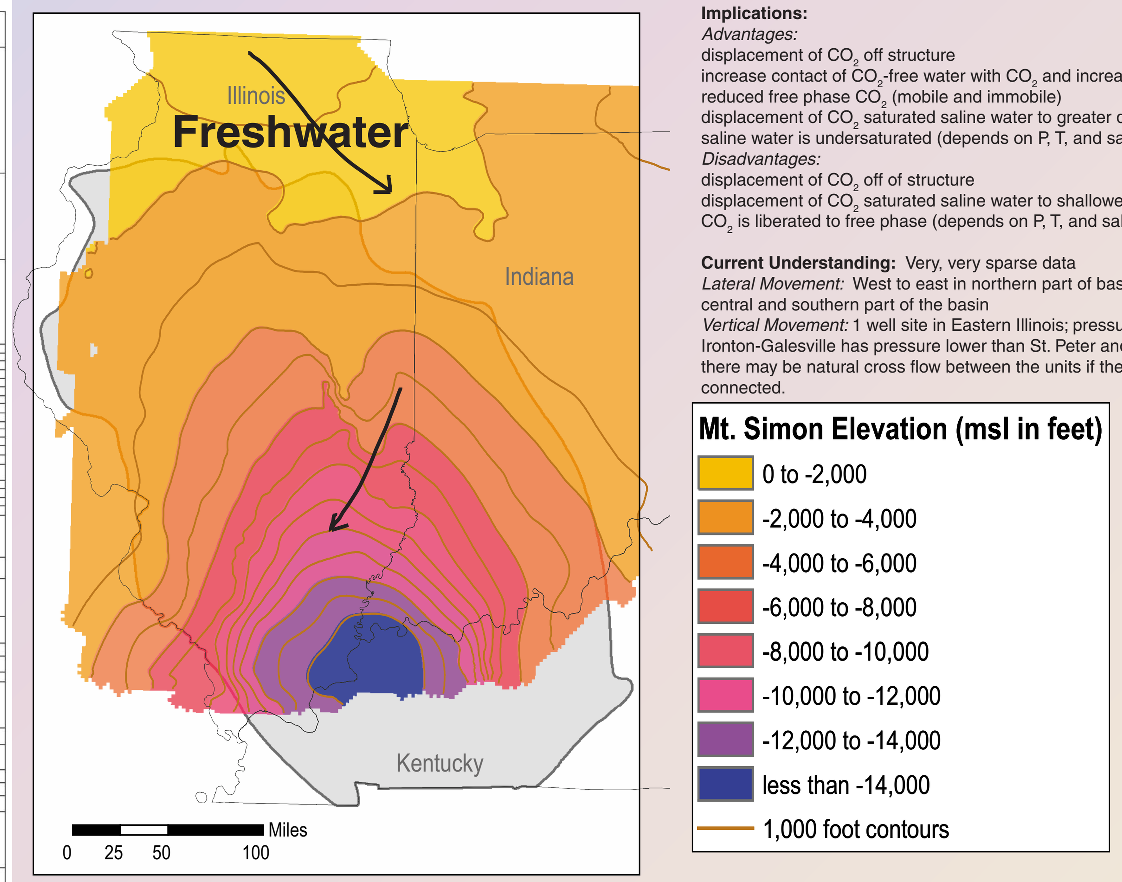


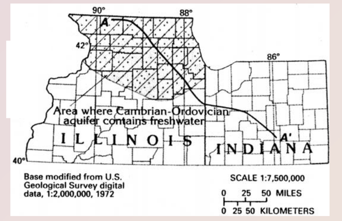
Potential Seal
Potential Sink
Coal Bed Potential adsorptive Sink and Seal

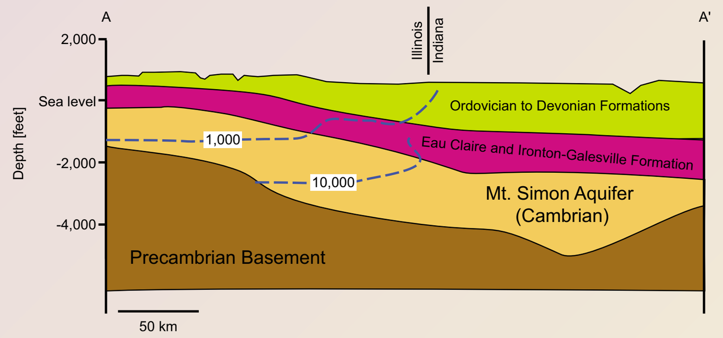
St. Peter Sandstone
The St. Peter Sandstone is an important aquifer in northern Illinois. It is a porous and permeable sandstone across most of the state of Illinois but is not present in the eastern part of Indiana. The St. Peter has been used for natural gas storage.

Mt. Simon Sandstone
The Mt. Simon Sandstone underlies all of the Illinois Basin except in local areas where it failed to cover the paleo-highs on the Pre-Cambrian surface. It attains a maximum thickness of 2600 feet in the east central part of Illinois and west central Indiana.

Geology of Saline Reservoirs in Illinois







Lateral and Vertical Movement of Saline Water

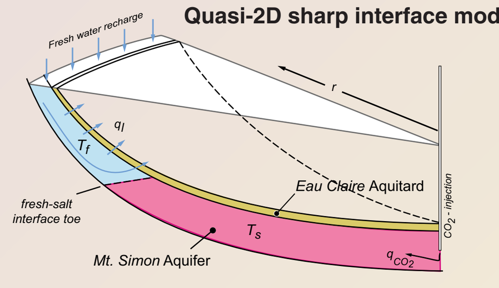
Implications:
Advantages:
displacement of CO_2 off structure
increase contact of CO_2-free water with CO_2 and increase dissolved CO_2
reduced free phase CO_2 (mobile and immobile)
displacement of CO_2 saturated saline water to greater depths such that saline water is undersaturated (depends on P, T, and salinity gradients).
Disadvantages:
displacement of CO_2 off of structure
displacement of CO_2 saturated saline water to shallower depths such that CO_2 is liberated to free phase (depends on P, T, and salinity gradients).

Current Understanding: Very, very sparse data
Lateral Movement: West to east in northern part of basin; north to south in central and southern part of the basin
Vertical Movement: 1 well site in Eastern Illinois; pressure data suggests Ironton-Galesville has pressure lower than St. Peter and Mt. Simon and there may be natural cross flow between the units if they are hydraulically connected.

At shallow depths, the Mt. Simon formation serves as an aquifer for the cities of Minneapolis/St. Paul and Chicago. Deeper in the basin, this formation becomes saline.

How Far is Water Displaced and How Fast is it Displaced? — Open System

Quasi-2D sharp interface model



Fresh water flow:

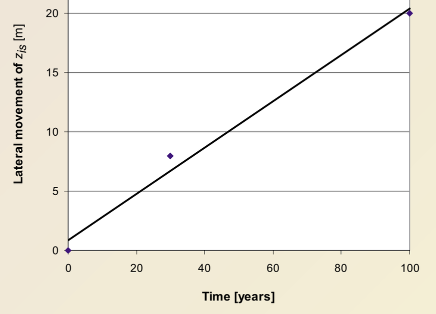
$$-n\frac{\partial z_{is}}{\partial t} = \frac{\partial}{\partial x}\left(T_f\frac{\partial h_f}{\partial x}\right) + \frac{\partial}{\partial y}\left(T_f\frac{\partial h_f}{\partial y}\right) - q_l$$

$$q_l = \frac{K_z}{b}(h_f - h_0)$$

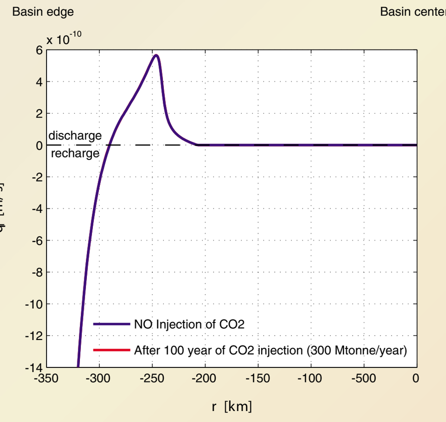
Brine movement:

$$n\frac{\partial z_{is}}{\partial t} = \frac{\partial}{\partial x}\left[T_s\frac{\rho_f}{\rho_s}\frac{\partial h_f}{\partial x} + T_s\left(\frac{\rho_s-\rho_f}{\rho_f}\right)\frac{\partial z_{is}}{\partial x}\right] + \frac{\partial}{\partial y}\left[T_s\frac{\rho_f}{\rho_s}\frac{\partial h_f}{\partial y} + T_s\left(\frac{\rho_s-\rho_f}{\rho_f}\right)\frac{\partial z_{is}}{\partial y}\right] + q_{CO_2}$$

Model Assumptions:
1 D radial model with recharge and discharge into the fresh water zone.
CO_2 modeled as second "brine water" phase No mass transfer between CO_2 and water.
5 degree radial model scaled to 360 degrees.
Eau Claire leak in freshwater zone only.
Freshwater/saltwater interface 150 km from injection site.



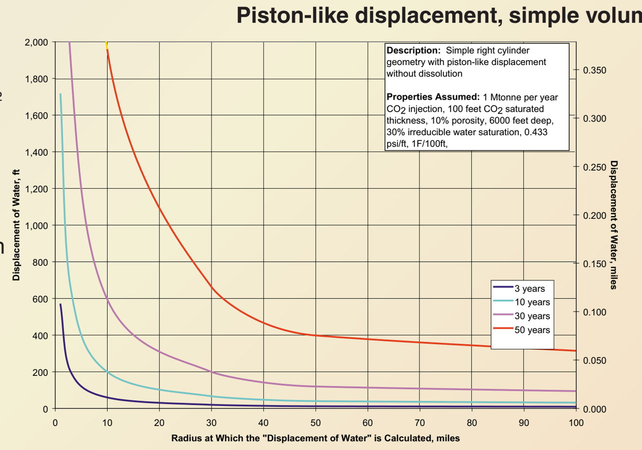
Leakage (q_l) of the fresh water leg is permitted across a confining unit (the Eau Claire Formation) while the system is being recharged along the basin fringe. The amount of leakage is determined by topographic differences and the permeability (K_z) and thickness (b) of the Eau Claire confining unit. Under steady-state conditions the salt water in the system will be immobile

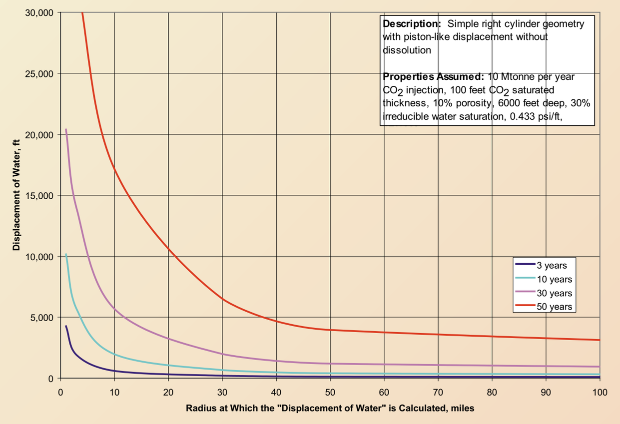


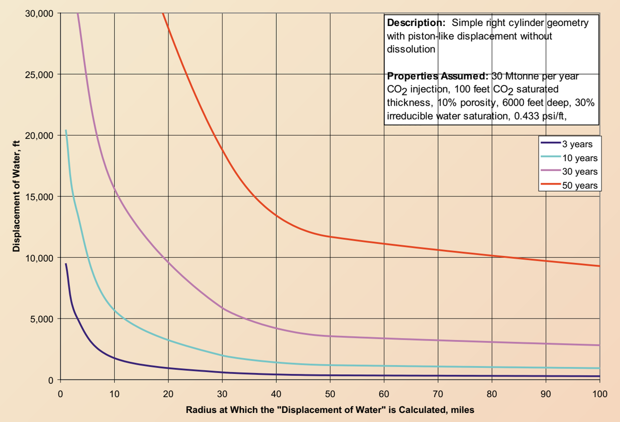
Changes in leakage rate (q_l) across the Eau Claire formation after 30 years of injection at 300 Mtonne/year. Negative values of q_l indicate recharge of the Mt. Simon aquifer through the Eau Claire unit, positive values indicate discharge.

No appreciable change in velocity or interface location for 100 years of CO2 injection. (Note: 300 Mtonne/year approximates the entire basin's current emissions from stationary sources)

Piston-like displacement, simple volumetric model







Velocity of Water Movement, feet/day			
Injection Rate Mtonne/yr	Distance from Injection site, miles		
	10	30	50
1.00	0.0181	0.0109	0.00182
10.0	0.178	0.108	0.0182
30.0	0.515	0.320	0.0545

The preliminary simulations presented here, show that the injection of large volumes of CO_2 has an inconsequential effect on the position of the fresh-salt water interface after decades of continuous injection. However, only one injection point is considered and the effect will be different when a larger number of injection wells is distributed throughout the basin.

In response to the movement of the fresh-salt interface, the dynamics of the fresh water part of the flow system will change. Both of these effects are important to consider in the evaluation of the long-term effects of CO_2 sequestration in deep saline aquifers since these formations are used as water supplies in large metropolitan areas at the margins of the basin.

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Conclusions

Understanding of the entire basin reservoir system is necessary in order to predict the consequences of carbon sequestration in saline reservoirs.

Increases in pressure will increase the amount of storage capacity in an closed reservoir due to pore, bulk volume, and water compressibility.

The amount of water movement away from the injection site, and the rate of displacement should be minimal in 10 Mtonne per year injection project.

Combination of pressure, temperature, and salinity gradients determine CO_2 solubility in brine water.

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