

Problem Statement and Overview

CO₂ has been injected for EOR in SACROC for 30 years. We assembled a 3-D numerical model with (1) a heterogeneous porosity and permeability distribution from seismic survey, (2) detailed mineralogy from experiment, and (3) brine composition from field data, and (4) production/injection data from oil company

The model was used to evaluate

1. Changes of rock properties due to chemical reactions associated with the injected CO₂.
2. The trapping mechanisms of CO₂ sequestration, including stratigraphic trapping of free CO₂, residual trapping, solubility trapping, and mineral trapping.
3. The different storage mechanisms between brine and oil reservoir

Site Characterization

1. Analysis of Geology

SACROC is the oldest CO₂ enhanced oil recovery operation in the United States, with CO₂ injection since 1972.

Geologically, the carbonate reef complex at SACROC is composed of massive amounts of bedded bioclastic limestone and thin shale beds representing the Strawn, Canyon, and Cisco groups of the Pennsylvanian and Wolfcampian.

2. Analysis of CO₂ Injection History

CO₂ injection: ~93 million tons
CO₂ production: ~38 million tons
Total accumulation: more than ~55 million tons

3. Analysis of Water Chemistry & ¹³C isotope at Track 207

Produced water from Cisco and Canyon groups: 840 samples
Shallow groundwater from Dockum group: 173 samples

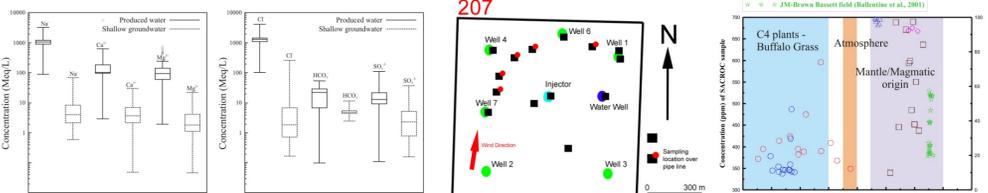


Figure 3. Comparison of water chemistry from produced and shallow groundwater and of ¹³C in SACROC with mantle originated ¹³C

The analysis of both water chemistry data and ¹³C suggested that Wolfcamp shale acts as a suitable seal in SACROC

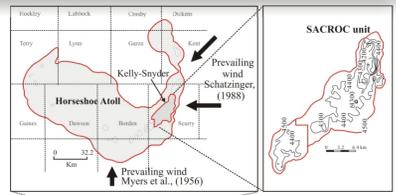


Figure 1. SACROC unit of the Horseshoe Atoll in western Texas

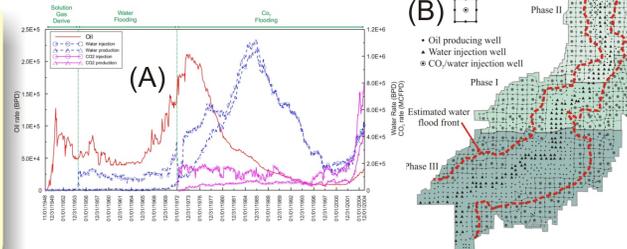


Figure 2. (A) Performance history of CO₂ injection and Production. (B) Locations of injection and Production wells

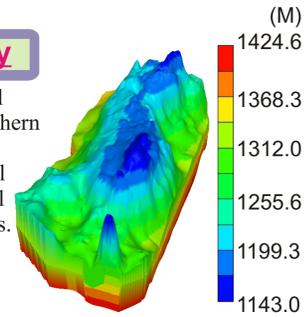
The evaluation of CO₂ storage mechanisms at SACROC in the Permian basin, site of 35 years of CO₂ injection

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Quantifying Natural Heterogeneity

A geologic model has been built for quantifying natural occurring porosity and permeability distribution at northern platform in SACROC by Texas Bureau of Economic Geology (Wang, Personal Communication). This model was based on analyzing the results of three dimensional seismic surveys and wire logs from four hundreds wells.

Figure 4. Geologic framework (9,450,623 nodes) describing Cisco and Canyon formations in northern platform SACROC.



Evaluation of Sequestration Type in Brine Reservoir

1. Upscaling of Permeability (Renormalization)

Renormalization developed through equivalent resistor network model is obtained (King, 1989)

2. Initial Conditions

- Pressure: From 1954 to 1971, water was injected to increase reservoir pressure. As a result, reservoir pressure becomes 16.65 Mpa (Dicharry et al., 1973; Langstone et al., 1988)
- Temperature: 54.5°C (Langstone et al., 1988)

3. Boundary Conditions

- Top boundary: no flow (Wolfcamp shale acts as a suitable seal)
- Eastern and western, and northern boundaries: no flow (Wolfcamp shale)
- Bottom boundary: no flow (Strawn is less permeable unit)
- Southern boundary: Hydrostatic pressure (Connected to the middle part of reservoir)

4. Transport Parameters

- Relative permeability (Drainage) is extrapolated from measured data at carbonate rock using supercritical CO₂ and brine at 41°C and 22.4MPa (Bennion and Bachu, 2005)
- Relative permeability (Imbibition) is modeled after Land (1969)
- Capillary pressure is extrapolated from two measured data at SACROC core gas and brine (50°C and 1.4 Mpa) using Parker et al (1987)

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5. Chemical Parameters - Equilibrium Reactions

1. H₂O = H⁺ + OH⁻
2. CO₂(g) + H₂O = H⁺ + HCO₃⁻
3. CO₂(g) + H₂O = 2H⁺ + CO₃²⁻
4. NaCl(aq) = Na⁺ + Cl⁻
5. NaCO₃ = Na⁺ + CO₃²⁻
6. NaHCO₃(aq) = Na⁺ + HCO₃⁻
7. CaCO₃(aq) = Ca²⁺ + CO₃²⁻
8. CaHCO₃⁺ = Ca²⁺ + HCO₃⁻
9. MgCO₃(aq) = Mg²⁺ + CO₃²⁻
10. MgHCO₃⁺ = Mg²⁺ + HCO₃⁻
11. Al(OH)₃ + 4H⁺ = Al³⁺ + 4H₂O
12. Al(OH)₃(aq) + 3H⁺ = Al³⁺ + 3H₂O
13. Al(OH)₂⁺ + 2H⁺ = Al³⁺ + 2H₂O
14. Al(OH)₂⁺ + H⁺ = Al³⁺ + H₂O
15. H₂SiO₃ = SiO₂(aq) + 2H₂O
16. FeCl₂ = Fe²⁺ + 2Cl⁻
17. FeCl⁺ = Fe²⁺ + Cl⁻
18. Fe(OH)₂ + 2H⁺ = Fe²⁺ + 2H₂O
19. Fe(OH)⁺ + H⁺ = Fe²⁺ + H₂O

- Kinetic Reactions

1. Calcite + H⁺ = Ca²⁺ + HCO₃⁻
2. Dolomite + 2H⁺ = Ca²⁺ + Mg²⁺ + 2HCO₃⁻
3. Kaolinite + 6H⁺ = 5H₂O + 2SiO₂(aq) + 2Al³⁺
4. Anhydrite = Ca²⁺ + SO₄²⁻
5. Quartz = SiO₂(aq)
6. Illite + 8H⁺ = 0.25Mg²⁺ + 0.6K⁺ + 2.3Al³⁺ + 3.5SiO₂ + 5H₂O
7. Ankerite = Ca²⁺ + 0.95Fe²⁺ + 0.05Mg²⁺ + 2CO₃²⁻
8. Dawsonite + 3H⁺ = Na⁺ + Al³⁺ + HCO₃⁻ + 2H₂O
9. Siderite = Fe²⁺ + CO₃²⁻

6. Spatial Distribution of Free and Residual CO₂

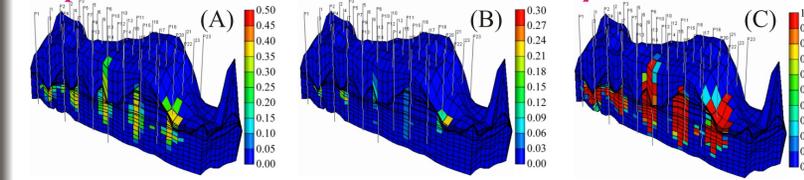
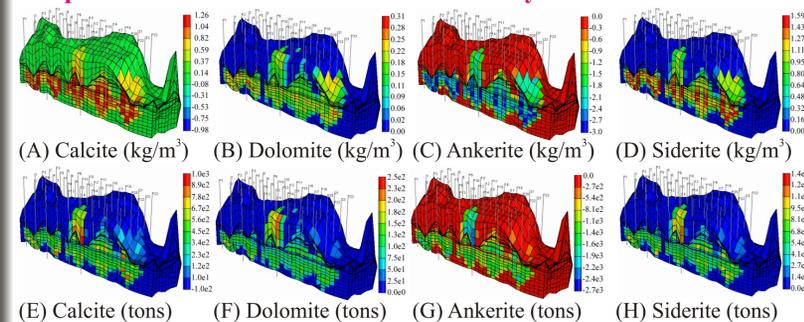


Figure 6. 2D cross-section view at 2002 year (30 years after CO₂ injection) (a) Saturation of separate CO₂, (b) relative permeability of separate CO₂, (c) Mole fraction of dissolved CO₂

When relative permeability of separate CO₂ is greater than zero, separate CO₂ becomes mobile. However, when relative permeability of separate CO₂ is equal to zero, separate CO₂ becomes immobile and trapped as residual CO₂.

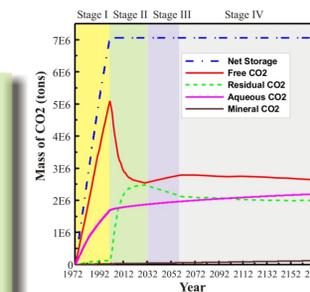
Like Juanes (2006), free CO₂ is located at the front of CO₂ plume, while residual trapped CO₂ is located at the tail of CO₂ plume

7. Spatial Distribution of Minerals at 2002 year



Ankerite dissolution provides Ca²⁺, Mg²⁺, and Fe²⁺ ions into brine. As a result, Ca²⁺, Mg²⁺, and Fe²⁺ ions are supersaturated in brine and triggered to precipitate calcite, dolomite, siderite, and anhydrite. Kaolinite and illite, respectively, precipitates and dissolves. The chemical reactions with aluminosilicate minerals disturb the concentration of Al³⁺ triggering to the precipitation of dawsonite.

8. Quantifying of CO₂ Storage Mechanisms



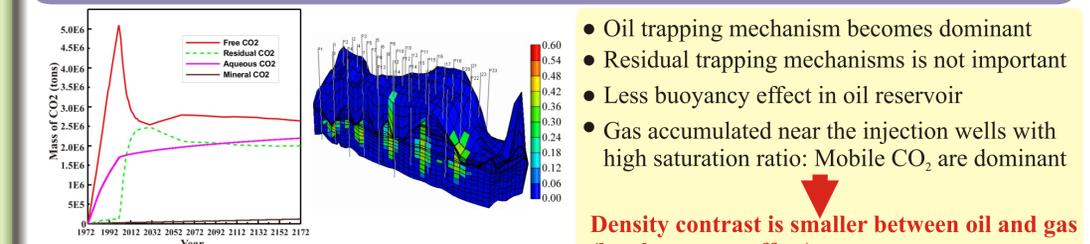
- (1) **Stage I (1972~2002):** Same as injection period. Free trapping is dominant. The saturation of CO₂ gradually increases near injection wells. At the same time, CO₂ migrates either vertically due to buoyancy driven force or horizontally through the preferential flow paths.
- (2) **Stage II (2002~2032):** Residual trapping mechanism becomes dominant. While CO₂ migrate either vertically or horizontally, some of free CO₂ becomes trapped into pores.
- (3) **Stage III (2032~2060):** The amount of free CO₂ slightly increases corresponding to the reduction of residual trapped CO₂ because CO₂ plume at certain injection wells migrate horizontally to neighboring injection wells where residual CO₂ is trapped.
- (4) **Stage IV (2060~after several hundreds years):** Solubility trapping mechanism becomes important because both residual and free CO₂ will dissolve into brine.
- (5) **Stage V (~after several thousands years):** Mineral trapping will be dominant because of dissolution of CO₂ will induce the disequilibrium between reservoir fluid and minerals

Evaluation of Sequestration Mechanisms in Oil Reservoir

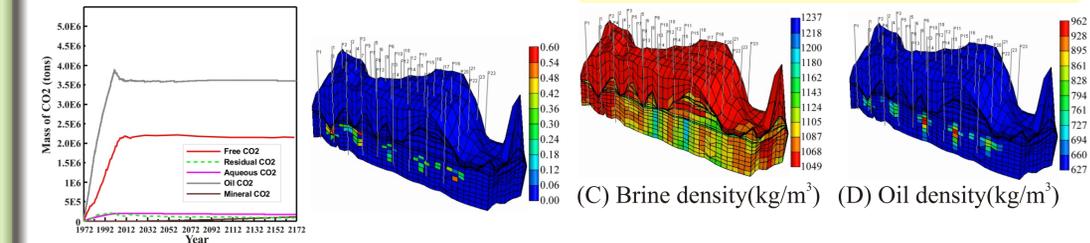
1. Model Input Parameters

- Pressure, temperature, brine concentration, mineral volume fraction, boundary condition: Same as the previous model
- Reservoir saturation: Water (0.28), Oil(0.72) (Vest, 1970)
- Oil composition (Dicharry et al., 1973): CO₂(0.0032), N₂(0.0083), C1(methane:0.2865), C2(Ethane:0.1129), C3(Propane:0.1239), I-C4(1-Butane:0.0136), N-C4(N-Butane:0.0646), I-C5(I-Pentane:0.0198), N-C5(N-Pentane:0.0251), FC6(Hexane:0.0406), C7+(Heptane plus:0.3015)

Comparison of Storage Mechanisms between Oil and Brine Reservoir



(A) Storage mechanisms and gas saturation without oil



(B) Storage mechanisms and gas saturation with oil

Conclusion

- At present(2007), Free CO₂: 3.5million tons, Residual CO₂: 1.7 million tons. Solubility trapped CO₂: 1.7 millions tons
- In brine saturated reservoir, both free and residual trappings are dominant mechanisms within 100 years. However, oil partially saturated reservoir, oil and free trappings are dominant mechanisms