

Aqueous Geochemistry of a Carbon Dioxide-Enhanced Oil Recovery Project in the Sugar Creek Oil Field, Western Kentucky

Kathryn G. Takacs¹, E.G. Beck², T.M. Parris¹, D. Wedding², and R. Locke³

¹Kentucky Geological Survey, University of Kentucky, 228 Mining and Mineral Resources Building, Lexington, KY 40506-0107, ktakacs@uky.edu

²Kentucky Geological Survey, University of Kentucky, 1401 Corporate Court, Henderson, KY 42420

³Illinois State Geological Survey, University of Illinois, 615 East Peabody Drive, Champaign, IL 61820

Approximately 7,200 tons of CO₂ was injected into the Mississippian Jackson Sandstone oil reservoir in the Sugar Creek field from May 2009 to May 2010. This enhanced oil recovery (EOR) project is part of the Midwest Geological Sequestration Consortium pilot program. Goals of this EOR project were: 1) assessment of the viability of using CO₂ for EOR in Kentucky, 2) characterization of aqueous geochemical responses to CO₂ injection, 3) estimation of the amount of CO₂ that remains sequestered, and 4) investigation of sequestration mechanisms in the reservoir.

Since its discovery in 1964, the Sugar Creek Field has produced approximately 34 percent (905,000 barrels) of the estimated original oil in place (2,680,000 barrels). The reservoir is a stratigraphic trap in a double lobe shape that dips down to the south of the injection well, with limited hydraulic interaction between the two lobes. Primary recovery was by solution gas drive, and secondary recovery via waterflood has been in place since 1993. Geochemical monitoring was performed before, during, and after CO₂ injection. Aqueous geochemical changes in the reservoir were monitored by the monthly collection of brine samples from eight production wells surrounding a single injection well. Also, three shallow groundwater monitoring wells, two domestic water wells, and one water-supply well were sampled quarterly to assure the quality of nearby shallow aquifers was not affected. During sampling, field measurements of temperature, specific conductance, pH, dissolved oxygen, and oxidation-reduction potential were taken for all wells. Water samples were analyzed for alkalinity, total CO₂, dissolved anions and metals, and total dissolved solids in the laboratory. An infrared gas analyzer was used to measure the concentrations of free-phase CO₂ at production wells. Gas samples were also collected for bulk and $\delta^{13}\text{C-CO}_2$ measurements. Reservoir pressure was monitored at the injection well, and surface pressure was monitored at the production wells.

Free-phase CO₂ was detected in five oil production wells, all on the west side of the field. Typically, after the arrival of CO₂ to the wellbore (i.e., breakthrough), pH decreased one pH unit, and chloride, calcium, strontium, and iron concentrations increased, on average, by 200 mg/L, 115 mg/L, 45 mg/L, and 2.5 mg/L, respectively. The pH decrease occurred very closely to the time of CO₂ breakthrough. Barium concentrations, in contrast, decreased. Aqueous geochemical changes occurred less than 1 to 4 months after CO₂ breakthrough. Since CO₂ injection was halted, pH values have generally remained below preinjection values, and most

other geochemical constituents have continued to increase in concentration. The sustained low pH values indicate that CO₂ is remaining in aqueous solution in the reservoir. No geochemical changes have been observed in the overlying aquifers that would indicate CO₂ leakage from the deeper reservoir formation.