Integrated CO₂ Storage and Brine Extraction

Kelsey Huntera, Jeffrey M. Bielickia,b,*, Richard Middletonc, Philip Staufferc, Rajesh Pawarc, Dylan Harpc, Daniella Martinezc,d

aDepartment of Civil, Environmental, and Geodetic Engineering, The Ohio State University, 470 Hitchcock Hall, 2070 Neil Avenue, Columbus, OH 43210, U.S.A.
bJohn Glenn College of Public Affairs, The Ohio State University, Page Hall, 1810 College Rd., Columbus, OH 43210, U.S.A.
cEarth and Environmental Sciences, Los Alamos National Laboratory, Los Alamos, NM 87545, U.S.A.
dChemical and Biological Engineering, University of New Mexico Albuquerque, NM 87131, U.S.A.

Abstract

Carbon dioxide (CO₂) capture, utilization, and storage (CCUS) can reduce CO₂ emissions from fossil fuel power plants by injecting CO₂ into deep saline aquifers for storage. CCUS typically increases reservoir pressure which increases costs, because less CO₂ can be injected, and risks such as induced seismicity. Extracting brine with enhanced water recovery (EWR) from the CO₂ storage reservoir can manage and reduce pressure in the formation, decrease the risks linked to reservoir overpressure (e.g., induced seismicity), increase CO₂ storage capacity, and enable CO₂ plume management. We modeled scenarios of CO₂ injection with EWR into the Rock Springs Uplift (RSU) formation in southwest Wyoming. The Finite Element Heat and Mass Transfer Code (FEHM) was used to model CO₂ injection with brine extraction and the corresponding increase in pressure within the RSU. The model was analyzed for pressure management, CO₂ storage, CO₂ saturation, and brine extraction due to the quantity and location of brine extraction wells. The model limited CO₂ injection to a constant pressure increase of two MPa at the injection well with and without extracting brine at hydrostatic pressure. We found that brine extraction can be used as a technical and cost-effective pressure management strategy to limit reservoir pressure buildup and increase CO₂ storage associated with a single injection well.

© 2017 The Authors. Published by Elsevier Ltd.
Peer-review under responsibility of the organizing committee of GHGT-13.

Keywords: Carbon dioxide capture, utilization and storage; enhanced water recovery; water use
1. Introduction

The reduction of greenhouse gas emissions from fossil fuels and the scarcity of water resources throughout the world are two major challenges for the energy sector [1]. CO₂ capture, utilization, and storage (CCUS) technology can store large quantities of CO₂ currently emitted to the atmosphere. The injection of CO₂ into a saline aquifer for storage increases the reservoir pressure limiting the quantity of CO₂ that can be injected per injection well, prompting an increase in the cost of CCUS and reducing its viability as a CO₂ emission reduction technology. Extracting brine during CCUS with Enhanced Water Recovery (EWR) can actively manage the increase in pressure from CO₂ injection and thus maintain or increase the CO₂ storage capacity, reduce the risks linked to reservoir pressure (e.g., induced seismicity and wellbore leakage), and manage the CO₂ plume [2–5]. This extracted brine could be desalinated for beneficial water use to partially or fully offset the water requirements for CCUS, provide additional water for power plant cooling, or satisfy other societal needs including regional water needs such as agriculture, or production of a marketable such as lithium through mineral extraction. The additional extraction wells and potential desalination and disposal of the extracted brine with EWR could be costly [6,7], but the additional CO₂ storage capacity due to brine extraction and the reduction of reservoir pressure during injection could incentivize EWR.

2. Methods

We considered CCUS with EWR by modeling subsurface flow and simulating pressure fluctuations associated with CO₂ injection and brine extraction in a deep, saline aquifer. We modeled CO₂ injection into a heterogeneous formation within the Rock Springs Uplift (RSU) Mississippian Lower Madison Limestone (Madison) formation in southwestern Wyoming. This developed a realistic representation of the pressure buildup scenarios that will determine how the CO₂ storage reservoir reacts to CO₂ injection and brine extraction and to determine potential pressure management strategies for subsurface CO₂ injection.

The RSU formation in Wyoming is a 50 mi x 35 mi area and characterized as a doubly-plunging anticline, which consists of a fold in the subsurface formation layers that can trap the buoyant, injected CO₂, with more than 10,000 feet of closed structural relief [8]. The Madison is the target CO₂ injection formation and is approximately 250 ft. thick at a depth of 7,500 ft. at the crest of the RSU, with the modelled site location greater than 12,000 ft. below ground surface. The subsurface layer is not exposed on the RSU and the nearest surface outcrop are 50 to 100 miles from the margins of the structure, resulting in the maintenance of the original saline characterizations and elimination of meteoric water recharge. The Madison is overlaid with 5,000 feet of low-permeability Cretaceous shale that can serve as a caprock and can store approximately 8 billion tons of CO₂ [8]. The existing fluid in the Madison formation has a salinity range of 50,000 to 80,000 ppm. Drinking water standards in the U.S. by the Environmental Protection Agency (EPA) limit drinking water sources to salinity levels below 10,000 ppm, which eliminates the Madison as a potential drinking water source (40 U.S. C.F.R.§ 144.3 (2016)). A stratigraphic test well (RSU #1) was drilled and completed in 2011 near the Jim Bridger’s Power Plant, the largest point-source of CO₂ emissions in Wyoming, generating approximately eighteen million tons of CO₂ (MtCO₂) per year [8,9]. The well was plugged and abandoned in October, 2013 [9].

The Finite Element Heat and Mass Transfer (FEHM; https://feml.anal.gov) Code is a control volume finite element method that simulates subsurface multi-fluid, multi-phase heat and mass transfer or complex subsurface processes in geologically complex basins [10]. We used a heterogeneous permeability and porosity field of the RSU Lower Madison formation characterized by seismic survey [11]. The mesh, developed using LaGriT (http://lagrit.lanl.gov), consists of a six by six km² area conforming the Darby, Lower Madison, Upper Madison, Amsden, and Weber formations interfaces between depths of 2.8 and 4.3 km. The Madison is the only formation with distinct porosities and permeabilities; all other formations were assigned porosities of 0.01 and permeabilities of 1x10⁻¹⁸ m². The Jim Bridger Fault is located approximately 7,500 feet northeast of the RSU #1 test well, which was used as a hypothetical injection well, and is incorporated in the model as a sealing fault with zero porosity.

We modeled a five-spot injection pattern in a sealed domain, with no flow vertical boundary conditions. The injection well (RSU #1) is located in the center of the pattern in a six by six km² mesh with extraction wells located approximately 1,042 m or 3,420 ft. from RSU #1. We simulated CO₂ injection in RSU #1 for two years at a constant pressure approximately two MPa higher than the hydrostatic pressure at the injection location. The first scenario injected CO₂ into RSU #1 without brine extraction in order to understand how CO₂ initially flowed through the reservoir and the potential interaction with closed boundaries and the Jim Bridger’s Fault. The subsequent simulations
incorporated up to four brine extraction wells that are equally spaced around the injection well and produce brine at hydrostatic pressure and were compared to the base scenario that did not have brine extraction.

3. Results

Figure 1(a) and 1(b) show the overpressure and CO$_2$ saturation after two years of CO$_2$ injection at RSU #1 without brine extraction.

The subsequent simulations included extraction wells to produce brine from the reservoir and maintain hydrostatic pressure. Figures 2–5 show the results of simulations with brine extracted from a single extraction well between the RSU #1 and the Jim Bridger’s Fault line (Figure 2), two extraction wells located north of RSU #1 (Figure 3), three extraction wells (Figure 4), and four extraction wells (Figure 5).
By increasing the number of wells and the location of these wells surrounding the RSU #1 CO$_2$ injection well, the overpressure is constrained towards the injection well, which limits the extent to which the CO$_2$ injection increases the pressure in the reservoir. The pressure differences in Figures 2b, 3b, 4b, and 5b indicate that the CO$_2$ pressure within the subsurface can be managed through the additional extraction wells. Figures 1b, 2c, 3c, 4c, and 5c display the saturation of CO$_2$ during the two year CO$_2$ injection cycle. Figure 6 shows the 90% CO$_2$ saturation contours for each scenario and shows the increase in the extent of the CO$_2$ plume.
Figure 7 shows a time series plot with the amount of CO$_2$ (MtCO$_2$) that is injected over the two years. Figure 8 shows the total mass of brine that was extracted and total mass of CO$_2$ injected for each scenario. Each additional brine extraction well increases the mass of CO$_2$ that can be injected into the formation and the amount of brine that can be passively extracted from the formation.

---

**Fig. 7.** The amount of CO$_2$ that is injected through RSU#1 well into the Madison formation for each brine extraction scenario.

**Fig. 8.** Comparison of total mass of CO$_2$ injected in MtCO$_2$ and brine extracted in Mt for all scenarios.
4. Conclusions

Brine extraction wells can be used to manage pressure during CO₂ injection and increase CO₂ storage capacity within the saline aquifer formation. Each additional extraction well relieves pressure buildup while increasing storage capacity for injected CO₂. CO₂ saturation in the reservoir is calculated for each scenario in order to indicate the extent of the CO₂ plume within the subsurface. Each additional brine extraction well increases the amount of CO₂ that can be injected into the CO₂ storage reservoir for a constant overpressure, using the extent of the 90% CO₂ saturations for each scenario as the metric for the size of the CO₂ plumes. The increase in these plumes as more extraction wells are added suggests that there will be an increase in the area of review, and associated costs, for CO₂ plume and leakage monitoring. Overall, brine extraction wells enable pressure management and provide increased storage capacity for CO₂, yet additional wells add significant expenses to a CCUS operation. Future work should be directed at understanding the cost-benefit relationship of extracting and managing brine during sequestration operations.

Acknowledgements

This project was funded by the U.S. National Science Foundation Sustainable Energy Pathways program (Grant 1230691), U.S. Geological Survey/Ohio Water Resource Center (Grant G16AP00076), and a U.S. DOE Mickey Leland Energy Fellowship awarded to Kelsey A. Hunter. We would like to acknowledge Terry Miller for her contributions to the Rock Springs Uplift mesh development.

References