CO$_2$-Enhanced Water Recovery through Integrated CO$_2$ Injection and Brine Extraction in the Rock Springs Uplift Formation in Southwest, WY

THESIS

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Abstract

The sustained release of greenhouse gases (GHGs) into the atmosphere is increasing global average temperatures and resulting in changes to the global climate. These changes can result in human and economic harm prompting increased research into the mitigation of GHGs specifically carbon dioxide (CO₂) emissions. Carbon dioxide (CO₂) capture and storage (CCS) technology may reduce CO₂ emissions by injecting CO₂ captured from large point sources (e.g., coal-fired power plants) into deep geologic formations for storage. The added mass of CO₂ typically increases reservoir pressure, which increases operational costs and risks linked to overpressure such as wellbore leakage, caprock fracture, and induced seismicity. The simultaneous extraction of brine during CO₂ injection can actively manage the reservoir pressure, reduce risks linked to overpressure, increase the reliable CO₂ storage capacity, redesign the CO₂ plume monitoring area, and potentially provide a new water source. This process is also known as CO₂ Enhanced Water Recovery (CO₂-EWR).

CO₂-EWR is modeled by integrating the Finite Element Heat and Mass Transfer code (fehm.lanl.gov) to simulate the flow of CO₂ and brine within the reservoir and a well model to connect the properties of CO₂ and brine at the surface to the properties in the reservoir. The integrated consideration of the two models determines optimal combinations of CO₂ injection and brine extraction rates and identifies relationships dictated by the injection and storage of CO₂ and brine extraction. I modeled CO₂-EWR in the Rock Springs Uplift (RSU) formation in southwest Wyoming and controlled the rates of CO₂ injection and brine extraction in order to understand the physical tradeoffs that affect the pressure evolution, CO₂ storage capabilities, and CO₂ Area of Review (AoR) in the aquifer.
Results indicated that the implementation of brine extraction can reduce the reservoir pressure and potentially facilitate increased capacity of CO$_2$ storage per unit of overpressure, yet this pressure drawdown can also be reduced below a threshold that facilitates flashing in the extraction wells and produced infeasible combinations of CO$_2$ injection and brine extraction. Brine extraction also impacts the CO$_2$ plume formation as it pulls CO$_2$ towards the extraction well, changing the shape and dimensions of the AoR, instigating premature breakthrough for high CO$_2$ injection and brine extraction rates, and reducing the time available for CO$_2$ storage. Finally, energy requirements, as a consideration of combinations of CO$_2$ injection and brine extraction, makes brine extraction less desirable because the scenarios that lead to the most CO$_2$ stored generally require the most energy. My research shows that combinations of CO$_2$ injection and brine extraction impact the physical tradeoffs within the reservoir during CO$_2$-EWR and it is important to understand these combinations in order to determine feasible and effective combinations of CO$_2$ injection and brine extraction.
Dedication

To my parents, for your unending love and support in everything I endeavor. Your encouragement to challenge myself has formed me into the person I am today and the person I continue to strive to be in the future.
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Thank you to Professor Jeffrey Bielicki for being my advisor and teaching me how to be a better student, engineer, and writer. Your constant drive for meaningful and clear results has enhanced my research skills and taught me the importance of our work.

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Fields of Study

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Chapter 1: Introduction

1.1 Climate Change, Carbon Dioxide, and Fossil Fuels

The release of greenhouse gases (GHGs) into the atmosphere and the resulting change in climate is one of the major challenges for present society (Melillo et al., 2014). The Intergovernmental Panel on Climate Change (IPCC) defines climate change as “a change in the state of climate that can be identified (e.g. using statistical tests) by changes in the mean and/or variability of its properties, and persists for an extended period, typically decades or longer” (Bernstein et al., 2007). The IPCC considers observations of climate change based on direct measurements and remote sensing from satellites and other platforms, drivers of climate change both natural and anthropogenic, human influence on the climate system, and future global regional climate change. The IPCC Fifth Assessment Report (AR5), released in 2013, estimated global climate change could increase global average temperatures 0.5 to 4 degrees Celsius and increase global average ocean levels between 0.26 and 0.82 meters by the year 2100 (Figure 1) (IPCC, 2013).
Figure 1: Figure 1.4 from the IPCC AR5 Shows the Estimated Changes in the Observed Globally and Annually Averaged Surface Temperature Relative to 1961-1990 (in °C) since 1950 Compared to the Forth Assessment Report (AR4). The observed anomaly of global annual mean surface temperature is shown as points and smoothed time series as solid lines for the National Aeronautics and Space Administration (NASA) (dark blue), National Oceanic and Atmospheric Administration (NOAA) (warm mustard), and the UK Hadley Centre (bright green). The colored shading shows projected changes to 2035 from models used in FAR, SAR, and TAR.

The changing of climate is anticipated to increase the frequency and intensities of extreme weather which combined with the sea level rise is expected to have mostly adverse effects on natural and human systems (Bernstein et al., 2007).

The change in climate is largely due to the accumulation of GHGs in the atmosphere, such as carbon dioxide (CO$_2$), methane (CH$_4$), and nitrous oxide (N$_2$O), absorbing infrared radiation, trapping heat, and making the climate warmer (Figure 2).
Although CO₂, CH₄, and N₂O naturally occur in the atmosphere, concentrations of these GHGs are increasing due to humans activities (IPCC, 2013; U.S. Environmental Protection Agency, 2017).

![Globally averaged greenhouse gas concentrations](image)

**Figure 2:** Figure SPM.1(c) from the IPCC AR5 Synthesis Report Depicting Atmospheric Concentrations of the Greenhouse Gases CO₂ (green), CH₄ (orange), and N₂O (red). Samples are determined from ice core data and from direct atmospheric measurements (lines).

Since 1750, CO₂ emissions increased by 44%, CH₄ emissions increased by 162%, and N₂O increased by 21%. In 2015, CO₂ was the principle GHG emitted in the United States and represents approximately 82.2% of total United States GHG emissions of which 93.3% is represented by fossil fuel combustion. Other sources of CO₂ emissions include iron and steel manufacturing, cement production, and land use changes through the conversion of forests to agricultural land or urban areas. Approximately 45% of the emitted
anthropogenic CO₂, which refers to GHG emissions that are a direct result of human activities or are the result of a natural process impacted by human activities (IPCC, 2006), remains in the atmosphere with the other 55% absorbed by the oceans and living biomass, known as CO₂ sinks (Le Quéré et al., 2015). In equilibrium, the carbon fluxes between CO₂ sources and sinks are balanced, but since the start of the industrial revolution the global atmospheric concentration of CO₂ emissions continue to rise. Sustained emissions of human related GHGs will result in further warming and changes in the climate system. In order to limit climate change, substantial and sustained reduction of GHG emissions is required.

The IPCC AR5 indicated that there is not a single technology option that can reduce GHG emissions to the level needed to achieve low-stabilization levels of 430-530ppm CO₂ equivalents (IPCC, 2014a). A CO₂ equivalent describes different greenhouse gases in a common unit by distinguishing the amount of CO₂ that would have the equivalent global warming impact. The goal of the Paris Agreement is to achieve these low-stabilization levels of CO₂ equivalents in order to hold global average temperatures well below 2°C above pre-industrial levels with strong efforts to limit the increase to 1.5 °C. A portfolio of mitigation measures will be needed to achieve these emission targets such as energy efficiency improvements to electricity generation, renewable energy technologies, nuclear energy, replacement of coal-fired power plants with natural gas combined-cycle power plants or combined heat and power plants, CO₂ capture and storage (CCS), and bioenergy with CO₂ capture and storage (BECCS) (IPCC, 2014b). Figure 3 show a potential mitigation pathway developed by the International Energy Agency (IEA) with various CO₂ emission reduction technologies needed to achieve the 2°C temperature stabilization target.
Figure 3: Figure from the International Energy Agency (IEA) Energy Technology Perspectives 2017 Summary Shows a Rapid Decarbonization Pathway. The pathway describes a method to limit global average temperatures to 2°C using a portfolio of mitigation strategies to limit the amount of CO₂ within the atmosphere.

Due to the continued use of fossil fuels as major energy sources, CCS is a viable strategy to mitigate carbon emissions while allowing continued large-scale use of fossil fuels (Celia et al., 2015). Additionally, in many ambitions mitigation scenarios using the representative concentration pathways (RCP) data, substantial CO₂ emission in the next year is necessary and net zero to net negative global CO₂ emissions is needed by 2080 (Millar et al., 2017). Net zero global CO₂ emissions refers to the balance of CO₂ released with an equivalent
amount of CO$_2$ sequestered from the atmosphere and net negative emissions result in higher CO$_2$ sequestration than CO$_2$ released into the atmosphere. Emission reduction pathways are only cost-effective with the use of CCS as an emission mitigation technology.

1.2 Carbon Dioxide Capture and Storage (CCS)

CCS is the process of separating CO$_2$ from an industrial or energy-related source before it is emitted to the atmosphere or extracting CO$_2$ from the atmosphere and then storing the GHG for long-term isolation from the atmosphere (IPCC, 2005a). Large point sources such as fossil fuel or biomass energy facilities are ideal locations to capture, compress, and transport CO$_2$ for storage. Storage methods include (1) geological storage in reservoirs such as oil and gas fields, unminable coal beds, and deep saline aquifers, (2) ocean storage through the direct release of CO$_2$ into the ocean water column or onto the deep seafloor, (3) mineral carbonation that fixates CO$_2$ in the form of an inorganic carbonate, and (4) industrial conversion processes that use CO$_2$ within a production process (IPCC, 2005a). Figure 4 is a schematic diagram of possible CCS systems provided by the IPCC Special Report Carbon Dioxide Capture and Storage (IPCC, 2005b). Through use of these different storage methods, energy forecasts conducted by the IEA project 14% of CO$_2$ emission reductions in 2050 will be through CCS technology in order for CO$_2$ mitigation strategies to be cost effective (International Energy Agency, 2013).
Figure 4: Figure SPM.1 from the IPCC Special Report on Carbon Capture and Storage of a Diagram with Possible CCS Systems. The diagram includes sources for CCS operations, transportation pathways for CO$_2$, and potential storage options.

This research focuses on geological storage of CO$_2$ as a potential CO$_2$ mitigation strategy. Ideal reservoirs for CO$_2$ injection and storage consist of sedimentary basins with high porosity and permeability such as sandstones and carbonates that facilitate high CO$_2$ injection rates. A low permeability rock layer such as shale, anhydrites, and salt beds without faults or fractures must overlay the injected formation essentially forming a caprock layer to prevent CO$_2$ from leaking into other nearby reservoirs or aquifers or inducing a significant seismicity event (Celia et al., 2015). These formation characteristics
are consistent with depleted oil and gas reservoirs and deep saline aquifers in sedimentary basins.

Oil and gas industries use CO₂ in tertiary oil recovery through Enhanced Oil Recovery (CO₂-EOR). For this process, CO₂ is injected into the oil reservoir pore space to facilitate crude oil production (NETL, 2010). The miscible properties of CO₂ and crude oil facilitate mutually solubility and allow the light hydrocarbons from the oil to dissolve in the CO₂ and CO₂ to dissolve in the oil. This enables CO₂ to effectively reduce the viscosity due to its miscible properties and to aid in the removal of oil from the reservoir. There are more than 130 CO₂-EOR operations worldwide with the majority of operations in the United States (Celia et al., 2015). The storage capacity for CO₂-EOR does not meet the needs for large scale CO₂ storage and mitigation. Sufficient storage capacity is necessary in order to accept the high injection rates from potential CO₂ sources.

Deep saline aquifers are potential options for large scale CO₂ storage. Over the past several decades, studies investigated and mapped deep saline aquifers for beneficial use. Feth conducted one of the first in-depth studies on mineralized ground water (Feth, 1965). The initial motivation of this research was to find appropriate fresh water supplies for future development and communities suffering from water scarcity. This research analyzed exploratory well borings in fresh and saline aquifers conducted throughout the United States to form a preliminary investigation into the distribution and availability of saline aquifer locations (Feth, 1965). An extensive compilation of saline aquifer characteristics and locations conducted by the National Energy Technology Laboratory (NETL) was released in 2015 (NETL, 2015a). Information gathered from the Regional Carbon Sequestration Partnerships (RCSPs) was compiled from across the United States to form a
comprehensive database. This database and the resulting atlas of saline aquifers known as the National Carbon Sequestration Database and Interactive Viewer (NATCARB) are focused on the use of deep saline aquifers for potential CO₂ sequestration sites (NETL, 2015b). Therefore, it only includes saline formations with salinity levels, total dissolved solids (TDS), greater than 10,000 ppm. The United States Environmental Protection Agency (EPA) Underground Injection Control Program (UIC) restricts the usability of saline aquifer formations. Class VI wells are used to inject CO₂ into deep geologic formations. These wells prohibit CO₂ injection into underground sources which contain a sufficient quantity of groundwater to supply a public water system and a TDS concentration less than 10,000 ppm (40 C.F.R. §144.3). NATCARB identified potential saline aquifers for CO₂ sequestration that will have subsurface ground characteristics needed for CO₂ sequestration and the ideal salinity levels for potential treatment without interfering with UIC restrictions. The storage capacity of deep saline aquifers in North America ranges from 2,379 to 21,978 giga metric tons (Gt) CO₂ while CO₂-EOR only ranges from 186 to 232 Gt CO₂ (NETL, 2015a). Since the annual emissions from large stationary sources in the United States, such as coal fired power plants, is approximately 3 GtCO₂/yr these deep saline aquifer storage sites have sufficient capacity to store large amounts of CO₂ over time (Celia et al., 2015).

The properties of CO₂ are also unique for geological storage. Once injected below a depth of 800 m, CO₂ becomes supercritical by exceeding the critical point (Temperature = 31.1°C and Pressure = 7.38 MPa) (Celia et al., 2015). At this super critical fluid state, CO₂ has a liquid density which improves storage capabilities because more mass can be stored per volume of pore space. Supercritical CO₂ density is significantly lower than the
density of formation water or brine resulting in a strong buoyant force of CO₂ towards the top of the formation.

1.2.1 Carbon Dioxide Capture and Storage Pilot Projects and Demonstrations

CCS is implemented by small industrial-scale operations around the globe. The Sleipner project in Norway is the first commercial application of deep saline aquifer CO₂ storage. Norway implemented a CO₂ emission tax in the early 1990s. The Norwegian oil company Statoil produces natural gas from a formation under the North Sea that has a high CO₂ content and must be separated before it can be sold. In 1996, the cost to emit the separated CO₂ was higher than the cost to compress and injected it into a different subsurface formation. Since October of 1996, approximately 1 MtCO₂/yr is injected each year into the Utsira formation under the North Sea (Celia, 2017; Torp and Gale, 2004). The Saline Aquifer CO₂ Storage (SACS) Project Consortium was founded in 1998 by a group of energy companies, scientific institutions, and environmental authorities in Norway, Denmark, the Netherlands, France, and the United Kingdom to monitor and collect data on the Utsira formation in the North Sea during the CO₂ injection operation. The In Salah project in Algeria started in 2004 and injected approximately 3.8 Mt CO₂ at a rate of 0.5 MtCO₂/yr until the operation was suspended in 2011 due to concerns with the integrity of the caprock seal (White et al., 2014). The United States currently has several CCS field projects such as the Illinois Basin Decatur Project. The project is a collaboration between the Midwest Geological Sequestration Consortium’s (MGSC), Archer Daniels Midland Company (ADM), and Schlumberger Carbon Services to inject 1 Mt CO₂ into the Mt. Simon Sandstone in Decatur, Illinois (NETL, 2015a). The CO₂ injection commenced in
November of 2011 and completed three years later in November 2014. CO₂ was injected at a nominal rate of 1,000 Mt/day with extensive monitoring of activities prior to injection, during injection, and will continue for ten years following completion. These projects demonstrate the application of CO₂ storage in deep saline aquifers but the annual injection rate of these operational projects remains significantly below the output from one large coal-fired power plant (Celia et al., 2015). Larger scale CCS operations and monitoring are necessary in order to determine applicability of the technology to mitigate large quantities of CO₂ as projected in energy models.

1.2.2 Carbon Dioxide Storage Concerns

The injection of CO₂ into porous and permeable reservoirs produces an increase in the reservoir pressure. This overpressure is highest near the point of injection and tapers off as the distance from this point of injection increases. Overpressure enhances a number of hazards for CO₂ storage, including leakage of fluids from the reservoir, activating faults, inducing seismicity, and compromising the integrity of the caprock (Bachu, 2008; Bielicki et al., 2016; Cihan et al., 2013; Deng et al., 2017; Morris et al., 2011; Rutqvist, 2012). Leakage is the primary risk in CO₂ storage (Celia et al., 2015). Leakage includes abrupt leakage through the failure of injection wells or leakage from abandoned wells and gradual leakage through undetected faults, fractures, or wells. Both forms of leakage potentially result in CO₂ and displaced brine to migrate into overlying rock formations, groundwater aquifers, and shallow soil zones, and eventually release at the surface or into the atmosphere. Consequences of leakage include potentially contaminated drinking water or other subsurface resources, harm to vegetation, and reintroduction of stored CO₂ into the

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atmosphere. The risks of leakage and its impacts along with the potential for induced seismicity during CO₂ injection and storage can lead to public opposition (Zoback and Gorelick, 2012).

Pathways for potential leakage include transmissive faults and fractures in the caprock. This form of leakage can be avoided through careful site selection and management of the pressure. The more common leakage pathway consists of defective or abandoned wells not properly capped. This is an issue for areas with prior geologic site investigation such as oil and gas operations with large quantities of existing exploratory, active, and abandoned wells (Brandt et al., 2014).

Previous studies estimate the potential impact of leakage by varying interacting parameters such as geophysical characteristics, CO₂ injection siting locations, and operational decisions in order to measure total leakage and the extent in which fluids migrate horizontally and vertically and that can threaten potential fresh water aquifers (Bielicki et al., 2015). Other models estimate the monetized leakage risk by simulating leakage and quantifying financial responsibility if CO₂ or brine interferes with subsurface resources and how this could be reduced by remediating these leaks (Bielicki et al., 2016).

Many assumptions for the site-specific characteristics of subsurface reservoirs are made during CCS modeling. This is typically due to the lack of data available including reservoirs’ permeability, porosity, and compartmentalization due to folds and fault lines that form boundaries of the site. Information for these reservoirs can be obtained through exploratory wells, seismic surveys, and production data if available. Further analysis can interpret these field measurements to develop general characteristics of the modeled reservoir. Without site specific information, uniform or homogeneous subsurface
properties are assumed which impacts the reliability and accuracy of model results. Additionally, geologic heterogeneity impacts the rate and associated costs of the volume of CO₂ injected and stored (Heath et al., 2012). Minor shifts in permeability to the subsurface may significantly impact the CO₂ storage costs, increasing the importance of accurate subsurface characterization.

1.3 Carbon Dioxide Enhanced Water Recovery (CO₂-EWR)

The overpressure induced by CO₂ injection and storage can be partially or fully relieved by (1) passive leakage of emplaced CO₂ or displaced brine through abandoned wells, faults, or fractures (Bielicki et al., 2015; Deng et al., 2017); or (2) the deliberate extraction of brine through Active CO₂ Reservoir Management (ACRM) (Buscheck et al., 2016a, 2016b, 2012; Kobos et al., 2011; Ziemkiewicz et al., 2015). This research investigates the second strategy through the simultaneous extraction of brine during CO₂ injection into deep saline aquifers. By actively managing the injected CO₂ and produced brine, allowable pressure build-up is minimized, which decreases the risks associated with overpressure during with CO₂ injection. This process aids in the management of reservoir pressure while providing a potential water source and is known as CO₂ Enhanced Water Recovery (CO₂-EWR). The extracted brine can be used for potential beneficial use through wastewater treatment to levels that are useful for a variety of applications, such as saline cooling, irrigation, off-setting the process water requirements for CO₂ capture, and perhaps providing drinking water depending on the amount of total dissolved solids, organics, and other substances that need to be removed from the brine (Kobos et al., 2011; Sullivan et al., 2013, 2012).
Additional benefits of brine extraction include the strategic extraction of brine to control the migration of the CO$_2$ plume and the size of the Area of Review (AoR). The AoR as defined by the Class VI rule (U.S. Federal Register, 2010) is “the region surrounding the proposed well where United States Drinking Waters (USDWs) may be endangered by the injection activity” [40 C.F.R. §146.84] (U.S. Environmental Protection Agency, 2013). This includes the largest spatial extent of the CO$_2$ plume within the saline aquifer or the “critical pressure,” which is the pressure needed to lift and transport formation brine from the CO$_2$ injection aquifer into protected groundwater aquifers if a pathway such as an unplugged well exists (Bandilla et al., 2012). Investigation into the AoR in terms of a brine extraction pressure management approach indicated that effective pressure management strategies require volume equivalent CO$_2$ injection and brine extraction. Brine extraction from the injection formation significantly reduced the pressure response and therefore the AoR. Reducing brine extraction rates to 75% of CO$_2$ injection rates resulted in an increase of the AoR size by a factor of three for scenarios with CO$_2$ injection near point sources such as coal fired power plant, suggesting a one-to-one volume exchange of CO$_2$ and brine is needed for effective pressure management (Bandilla and Celia, 2017). Pressure management may not be necessary for all storage operations, specifically annual injection rates less than 1Mt CO$_2$ of storage, because the AoR is essentially equal to the CO$_2$ plume and not the pressure increase, indicating that pressure would not be able to decrease the size of the AoR.

Prior studies also suggest that brine extraction, and the possibility that concentrated brine may need to be disposed after treatment, is more costly than without brine extraction (Bourcier et al., 2011). Yet the benefits of brine extraction through pressure management
could outweigh the costs of treatment and disposal. These benefits could change as the demands of water resources increase due to the impacts of a changing climate. A potential new source of water could become more valuable in the future.

1.4 Changing Water Demands and the Energy-Water Nexus

Thermoelectric generating facilities, such as coal fired power plants, are potential sources of CO₂ emissions that can be used for CO₂-EWR. These facilities are also very water intensive processes. The USGS estimated total United States water withdraws to be approximately 355 billion gal/day in 2010 (Maupin et al., 2014). As of 2010, thermoelectric power consisted of 45% of the total water withdrawals. Thermoelectric sources represent the highest water withdrawal rate at approximately 161 billion gal/day, 99% of which consist of surface water withdrawals and 73% of which are freshwater sources. The water used for thermoelectric power is typically used during electricity generation through stream turbine generators and cooling systems. Cooling systems have a significant impact on the amount of water withdrawn or consumed during the generation of electricity. Once-through cooling for thermoelectric power sources occur when withdrawn water is cycled through a heat exchanger and then released to the environment. Due to its heavy withdraw rate, once-through cooling technologies are being replaced by recirculation systems, which circulate water through heat exchangers and then cool the water before re-injection as new cooling water (Averyt et al., 2011). Recirculation cooling systems decrease the overall water withdrawal for thermoelectric systems, but increase the consumption rate, as water is continuously recycled through the system until evaporation.
The demand for electricity is projected to increase by 24% and the resulting water consumption for thermoelectric power is projected to increase between 36-43% by 2035 (Tidwell et al., 2012). Additionally, a recent study indicated that one fifth of 400 watersheds in the United States that are experiencing water-supply stress are significantly impacted by thermoelectric power water withdrawal (Averyt et al., 2011). With increased concerns throughout the United States on regional water stress and the raise in electricity demand, the interdependencies between energy production and water availability need to be evaluated in order to identify potential solutions that can be implemented to lessen the impact of increased regional drought conditions.

The potential disruption of electricity generation due to regional water stress resulted in increased investigation into the relationship between energy and water. In July of 2014, the U.S. Department of Energy (DOE), released a report titled, “The Water-Energy Nexus: Challenges and Opportunities” (Battey et al., 2014). This report identified DOE’s previous work on the relationship between water and energy, proposed six strategic pillars to address the energy-water nexus, and recognized technological research, development, demonstration, and deployment (RDD&D) opportunities for the DOE. In November of 2014, the United States and China launched the United States-China Clean Energy Research Center (CERC), identifying a joint work research area of energy and water (The White House, 2014). This joint coalition brought global attention to the critical water demand needed for the generation of energy and formulated a call for action to address the challenge.

An additional concern within the electricity sector is the ability to limit CO₂ emissions. Through the Clean Water Act, new thermoelectric power plants are required to
use the best available technologies to reduce environmental impacts. This promotes the use of closed-loop cooling systems, dry cooling systems (in certain regions), and increased interest in amine-based post combustion carbon capture (33 U.S.C. §1251-1387). In addition, the U.S. EPA announced the “Clean Power Plan,” on August 3, 2015, which mandates reductions in CO₂ produced by electricity production in order to address climate change (Environmental Protection Agency, 2015). These emission reductions can be addressed through the implementation of CCS operations. Yet, the addition of CO₂ capture and storage systems significantly impacts the cost and water use of thermoelectric power plants (Zhai et al., 2011; Zhai and Rubin, 2010). Capture technologies are expensive due to high water resources requirements, energy demands, and electricity costs. The water demand for coal burning power plants with an amine based CO₂ capture system doubles the water requirement (Zhai et al., 2011). The overall consumptive water demand of these facilities fluctuates by plant system type, location, changes in ambient temperature and other regional factors. Improvement of overall plant thermal efficiency through the use of super critical boilers, recycling/reuse of plant water, advanced cooling technologies and alternative water sources can be used to help mitigate this problem, yet the addition of CO₂ capture remains the most significant impact on plant performance, cost and water use.

CO₂-EWR technology approaches the injection of CO₂ into saline formations as an opportunity to produce brine, which can be used as a potential new water source. On September 16, 2015, the DOE selected five projects in its efforts to study the feasibility of using extracted water from CO₂ storage sites as a freshwater source (The U.S. Department of Energy, 2015). The projects study the process of pumping CO₂ into saline aquifers by
managing the pressure of CO₂ flow in order to operate enhanced water recovery (CO₂-EWR) systems.

Two of the major challenges within the electricity sector are the reduction of water to produce electricity and the reduction of CO₂ emissions formed during production (Buscheck and Bielicki, 2015). The use of CO₂-EWR to decrease CO₂ emissions and produce a portion of brine could be a potential solution to these concerns through CO₂ mitigation and brine extraction.

1.5 Modeling Carbon Dioxide Enhanced Water Recovery (CO₂-EWR)

Due to the high availability and increased accuracy of subsurface modeling technology the implications of CO₂ storage and brine extraction can be analyzed for a multitude of conditions and locations. Kobos designed a hypothetical case study in the southwestern United States to investigate the impacts of subsurface groundwater chemistry due to the injection of CO₂, the management of the reservoir, and desalination treatment options (Kobos et al., 2011). Kobos used the REACT model coupled with in situ pore water chemistry and formation mineralogy to determine the geochemical implications of CO₂ injection (Bethke, 1998). The REACT model is combined with the TOUGH2 (Pruess, 2004) model for reservoir modeling of the subsurface CO₂ plume and water extraction and treatment methods. A single integrated assessment model (IAM) is then used to combine and evaluate all of the components of the REACT, TOUGH2, and water treatment systems. Results indicated that adding a CCS system to an existing power plant in an ideal CO₂ injection location increased the energy consumed by approximately 20%, increased the water use by 43%, and reduced CO₂ emissions from 13 Mt/yr to 9 Mt/yr. In comparing a
power plant combined with CCS to a power plant with CCUS and CO₂-EWR, there is a marginal increase in the net CO₂ emissions and an increase in cost by less than 1 $/kWh. Uncertainties and cost fluctuations expressed in this paper included the analysis of the amount of CO₂ that can be captured, the geological formation characteristics such as permeability and porosity, and the impacts on future regulatory constraints. Future work indicated an expansion of the modeling framework to include additional United States formations. It also suggested the ability of users to obtain data from existing saline formation databases such as NATCARB, and build from existing geochemical and geomechanical studies of CO₂ storage to develop custom, site-specific characteristics.

Modeling research conducted by Klise used non-traditional water sources from saline aquifer formations to meet the cooling-water demands for CCS systems (Klise, 2013). This research projected water requirement and the additional cost associated with a CCS system combined with a natural gas combined cycle (NGCC) power plant. It used saline formation parameters from the 2008 NETL NATCARB database, subsurface research conducted at the Gulf Coast Carbon Center (GCCC), production well data from the Kansas Geological Survey (KGS), and geothermal heatflow database from Southern Methodist University. It is expected that combining a CCS with a NGCC would increase the power plant’s water consumption in between 50-90% (NETL, 2009). Reverse osmosis is used to treat the brine to a desired salinity range of 200-300 ppm TDS in order to reduce the cost and need for additional chemicals to be added to the cooling water and prevent the corrosion of the power plant cooling system and tower. The produced brine concentrate for reverse osmosis is then re-injected back into the source formation. The usable salinity range in the model is 10,000 ppm to 35,000 ppm TDS because a TDS value lower than 10,000
ppm may be considered a drinking water source and a TDS value higher than 35,000 ppm increased the cost due to high-energy cost for treatment with lower membrane efficiency (Miller, 2003). In determining the probability of saline water extraction and treatment, it is assumed that the natural gas power plant injected CO$_2$ and extracted brine at the site. First, the possibility of drilling an extraction well is determined followed by the injectivity potential for a given formation. The amount of extracted water is determined by the CO$_2$ injected and an injectivity ratio. Additional water requirements are calculated, geologic formation capacity is evaluated, and CO$_2$-storage lifetime is assessed for the formation. The overall costs associated with utilizing and treating produced brine resulted in a function of the probability of drilling a usable well and the cost to treat the water based on salinity. All of these factors are incorporated into the Water, Energy and Carbon Sequestration Simulator (WECSsim).

Results indicated that water could be extracted from 96% of the 185 formations investigated and meet the cooling demands of 80% of the CCS scenarios for a 300-MW and 47-MW NGCC power plant (Klise, 2013). Water costs are below $4/m$^3$ for 93% of the formations and less than $10/t$CO$_2$ injected for 90% of formations. Future analysis of this study could incorporate transportation costs of brine to treatment and storage facilities or CO$_2$ from thermoelectric sites to CCS locations. Additional considerations include the use of pressure from the produced water to meet the energy needs for reverse osmosis while providing the water resources for both the CCS system and thermoelectric plant.
1.6 Carbon Dioxide Capture and Geological Storage Costs

Geological CO₂ storage costs remain uncertain, although the past decade has provided increased research and detailed breakdown of costs. The uncertainty includes the impact of regulations on total storage costs including monitoring, long-term stewardship, and liability. Another area of uncertainty includes public acceptance and its projections on economics, which occurred with the growth of hydraulic fracturing for natural gas production as public concerns led to changes to operational procedures (Rubin et al., 2015). The Special Report on Carbon Capture and Storage (SRCCS) from the IPCC reported costs of CO₂ geologic storage ranged from 0.5 to 8 in 2002 (United States Dollar) USD/tCO₂ with additional monitoring costs of 0.1 to 0.3 in 2002 USD/tCO₂ (IPCC, 2005a). More recent estimates from the Global Carbon Capture and Storage Institute (GCCSI) reported a range of 6 to 13 2013 USD/tCO₂ (Global CCS Institute, 2011) and the United States Department of Energy (USDOE) reported a range of 7 to 13 USD/tCO₂ (USDOE, 2014). The percent increase in total levelized cost for a CO₂ capture, transport, and geological storage operation in comparison with a power plant without CCS in constant 2013 USD is 28% to 72% for a natural gas combined cycle (NGCC) power plant with post-combustion capture, 48% to 98% for a supercritical pulverized coal (SCPC) power plant with post-combustion capture, 61% to 114% for a SCPC with oxy-combustion capture, and 26% to 62% for a pre-combustion capture at goal-based integrated gasification combined cycle (IGCC) power plant (Rubin et al., 2015). For most CCS systems, the cost of capture is the largest cost component. Costs for various components of a CCS system vary widely, depending on the reference plant and the wide range in CO₂ source, transport and storage situations. As new technologies become available that are still in the research and
demonstration phase, the cost of capture could be reduced. These technologies can be retrofitted with existing plants for CO₂ capture and can be compatible with current energy infrastructure making these CCS technologies more cost competitive.

As energy infrastructure transitions to new and more efficient energy generation technologies, CCS can be used to capture CO₂ and reduce overall CO₂ emissions. Emission reduction can be incentivized by setting a value on CO₂ mitigation such as a tax or cap-and-trade policy. The Emergency Economic Stabilization Act in October of 2008 proposed a tax credit of $20 per metric ton for CO₂ captured at a qualified facility and disposed in a secure geologic storage facility (H.R. 1424, Emergency Economic Stabilization Act of 2008, 2008). Additionally, the American Clean Energy and Security Act of 2009 proposed a comprehensive national climate and energy legislation that would establish a GHG cap-and-trade system (H.R. 2454, American Clean Energy and Security Act of 2009, 2009). Although these incentives are not implemented, I can use the established pricing system from the Emergency Economic Stabilization Act to set initial pricing for CO₂ storage.

1.6.1 Brine Extraction Treatment Costs

Treatment is necessary for brine extracted during CO₂-EWR because at high salinity values, typically over 10,000 ppm TDS, the withdrawn fluids are not usable for most industrial operations, agriculture, or public supply (Bourcier et al., 2011). With the potential to produce a significant amount of water through a high injection of CO₂, the large volume of high salinity water can be desalinated and treated for potential other uses. Research using the USGS Produced Brine Database with a TDS range of 10,000 ppm to 85,000 ppm and treatment technologies including thermal distillation, reverse osmosis, and
nanofiltration indicated major cost savings due to the use of wellhead pressure obtained through CO$_2$ injection for the required treatment pressure during reverse osmosis (Bourcier et al., 2011). With this assumption, water treatment for brine, with equal salinity to seawater, is half the cost. This cost prediction does not include the cost of site-dependent factors, wells, or pipelines. For a fresh water production using a rate of 6 million gal/day the treatment cost of produced water from CO$_2$-EWR using well-head pressure ranged from 32 to 40 ¢/m$^3$. Without the well-head pressure costs ranged from 60 to 80 ¢/m$^3$, which is similar to the desalination of seawater.

A CO$_2$-EWR system could produce a significant volume of water. For a 1GW coal plant that emits more than 7 MtCO$_2$/yr and a CCS system with 6 MtCO$_2$ storage capacities at a depth of 300 m, there is a potential to produce 8 million m$^3$ of water per year (Bourcier et al., 2011). By treating this water through reverse osmosis with a recovery rate of 40%, this system would provide 3.2 million m$^3$ of fresh water. The remaining saline water could then be re-injected into the aquifer system, which can be used with the management of the CO$_2$ plume.

1.7 Purpose of Thesis

In modeling CCS systems there remain two critical issues, (1) the high energy demand and resulting cost associated with the capture process and (2) the management of injecting large volumes of CO$_2$ into the a reservoir, which can potentially cause unintended environmental consequences (Celia et al., 2015). This research attempts to address the second issue through the use of CO$_2$-EWR to manage the high pressure in reservoirs due to CO$_2$ injection. Future work will address the first issue by developing a cost minimizing
optimization that assigns costs for the construction and operation of a CO₂-EWR facility and profits due to a CO₂ price and reused water price.

I integrated a well and reservoir model to simulate CO₂-EWR for a case study in the Rock Springs Uplift (RSU) Lower Madison formation. This simulation is used to evaluate reservoir characteristics for a heterogeneous reservoir formation with combinations of simultaneous CO₂ injection for storage and brine extraction as a form of pressure management. The response of the reservoir to CO₂ injection and brine extraction rates helped to determine infeasible combinations of these CO₂ injection and brine extraction rates. The results and analysis provided data about the characteristics of the case study, which determine general characteristics of a CO₂-EWR system and the potential benefits of reservoir management through active brine extraction.
Chapter 2: Methods and Case Study

I combined a reservoir model simulating CO\textsubscript{2} injection and brine extraction with a model for fluid flow in the injection and extraction wells in order to estimate how different combinations of injection rates and extraction rates affect important systems-level characteristics of geologic CO\textsubscript{2} storage (e.g., overpressure, CO\textsubscript{2} plume migration, energy requirements). The reservoir modeling simulations provided information on the pressure, temperature, enthalpy, CO\textsubscript{2} saturation, and CO\textsubscript{2} density in three dimensions within the reservoir mesh. The well model used the pressures, temperatures, and enthalpies at the exit of the injection well to estimate the corresponding states of the CO\textsubscript{2} at the entrance of the injection wellhead and the pumping power that is necessary to inject CO\textsubscript{2} into the reservoir over time. Similarly, the reservoir model provided information on the state of the brine at the inlet of the brine extraction well, which is then used to estimate the properties of the brine at the production wellhead and the pumping power that is required to produce that brine to the surface.

2.1 Reservoir Modeling

I used the Finite Element Heat and Mass Transfer (FEHM) Code (http://fehm.lanl.gov) developed by Los Alamos National Laboratory in the reservoir model to simulate reservoir performance with CO\textsubscript{2} injection and brine extraction. The FEHM code uses a control volume finite element method that models subsurface multi-fluid, multi-phase heat and mass transfer, and complex subsurface processes (Zyvoloski, 2009).
The FEHM model simulates complex reservoir processes in porous media. The elemental components of the code include flow and energy transport, fracture flow, solute-transport, and constitutive relationships for pressure and temperature dependent properties of a fluid or gas (Zyvoloski et al., 1997). For this research, I disregard the components that model fracture flow and solute-transport in FEHM because they simulate leakage within fractures in targeted reservoir, which is out of the scope of this research.

The flow and energy transport equations simulate heat conduction, heat and mass transfer for multiphase flow within porous and permeable media, and non-condensable gas flow within porous and permeable media. FEHM assumes Darcy’s law for fluid flow which restricts the velocity, sets a thermal equilibrium between fluid and rock, distinguishes the formation in an immovable rock phase, and negates viscous heating. Since the derivations of the governing equations are analogous for heat conduction, heat and mass transfer for multiphase flow within porous and permeable media, non-condensable gas flow within porous and permeable media, only the heat and mass derivation is presented. The units are provided as mass (M), length (L), time (τ), and temperature (T). The governing equations include the conservation of mass for water:

\[
\frac{\partial A_m}{\partial t} + \nabla \cdot \vec{f}_m + q_m = 0
\]

(1)

where \( A_m \) is the mass per unit volume (M/L^3), \( t \) is time (τ), \( f_m \) is the flux vector for the mass equation (M/L^2τ), and \( q_m \) is the mass source term (M/L^3τ), the conservation of fluid-rock energy:
\[
\frac{\partial A_e}{\partial t} + \nabla \cdot \vec{f}_e + q_e = 0
\]  \hspace{1cm} (2)

where \(A_e\) is the energy per unit volume (M/L\(\theta^3\)), \(f_e\) is the flux vector for the energy equation (M/\(\theta^3\)), and \(q_e\) is the energy source term (M/L\(\theta^3\)), and Darcy’s Law applied to the movement of each phase:

\[
\vec{v}_v = -\frac{k_{R_v}}{\mu_v} \left( \nabla p_v - \rho_v g \right) \hspace{1cm} (3)
\]

\[
\vec{v}_l = -\frac{k_{R_l}}{\mu_l} \left( \nabla p_l - \rho_l g \right) \hspace{1cm} (4)
\]

where \(v\) is the velocity vector for vapor (L/\(\theta\)), \(k\) is the intrinsic rock permeability (L\(^2\)), \(R\) is the universal gas constant (8.314 kJ/mol-K), \(\mu\) is the viscosity (M/L\(\theta\)), \(P\) is the pressure (M/L\(\theta^2\)), \(\rho\) is the density (M/L\(^3\)), and \(g\) is the acceleration of gravity (L/\(\theta^2\)). The subscript \(v\) represents vapor properties and \(l\) represents liquid properties. Darcy’s Law combines with the basic conservation equations of mass for water and fluid-rock energy:

\[
-\nabla \cdot \left( (1 - \eta_v)D_{mv} \nabla p_v \right) - \nabla \cdot \left( (1 - \eta_l)D_{ml} \nabla p_l \right) + q_m + \frac{\partial}{\partial z} g((1 - \eta_v)D_{mv}\rho_v + (1 - \eta_l)D_{ml}\rho_l) + \frac{\partial A_e}{\partial t} = 0 \hspace{1cm} (5)
\]

\[
-\nabla \cdot (D_{ev} \nabla p_v) - \nabla \cdot (D_{el} \nabla p_l) - \nabla \cdot (K \nabla T) + q_e + \frac{\partial}{\partial z} g(D_{ev}\rho_v + D_{el}\rho_l) + \frac{\partial A_e}{\partial t} = 0 \hspace{1cm} (6)
\]
where $\eta$ is the mass fraction of air, $K$ is the thermal conductivity (ML/T$^3$), $Dm$ is the mass-transmissibility term (L$^2$/T), $T$ is the temperature (T). When all convective terms are eliminated the final form of the pure heat-conduction equation is formed.

$$\nabla \cdot (K\nabla T) + q_e + \frac{\partial A_e}{\partial t} = 0 \quad (7)$$

To simulate the flow and energy transport within a porous medium, the densities, viscosities, and enthalpies of water, water vapor, and air are required and depend on temperature and pressure. The National Bureau of Standards Steam Tables are used for the pressure and temperature that are used as inputs to the nodes within the reservoir mesh, which output the densities, viscosities, and enthalpies of the phases. Relations for temperatures can be computed up to 360°C and pressures up to 110 MPa. The implicit code of FEHM uses a Newton-Raphson iteration in order to derive the thermodynamic functions with respect to pressure and temperature. It includes the relationship of pressure as a function of saturation temperature and temperature as a function of saturation pressure, which accounts for the prevention of water reaching boiling point. Properties of air and air-vapor mixtures follow the ideal gas law and the mass-fraction of air in the liquid phase obeys Henry’s Law. Relative-permeability simple linear functions such as the Corey (1954) relationships and the van Genuchten (1980) functions are available to model relative permeabilities and capillary pressures. A linear and nonlinear model are incorporated into the FEHM code to account for changes in the rock porosity and permeability changes in effective stress through temperature and pore-fluid pressure changes. Finally, a linear
temperature-dependent model and a relation based upon the square root of liquid saturation are incorporated in the FEHM code to characterize thermal conductivity of the solid, which is a function of temperature or liquid saturation. These relationships are parameters incorporated into the code. The CO\textsubscript{2} equations of state are similarly built into a lookup table that captures the transition from supercritical fluid to liquid or gas across the region of discontinuous derivatives.

The FEHM code has been used in numerous prior studies involving reservoir modeling, including the evaluation of uncertainty in CO\textsubscript{2} storage capacity and well injectivity (Surdam et al., 2013b), assessment of the distribution and migration pathways of CO\textsubscript{2} in the subsurface (Deng et al., 2012), and robust pressure management strategies during CO\textsubscript{2} injection (Harp et al., 2017).

2.2 Well Modeling

I implemented a well model in order to estimate the amount of power that is necessary to inject CO\textsubscript{2} into, or produce brine from, the reservoir over time. The well model is based on a previous study for a CO\textsubscript{2}-Plume Geothermal (CPG) system, which uses CO\textsubscript{2} to extract heat generated by the earth, that connects a reservoir model to a well power plant model in order to estimate that power outputs (Adams et al., 2015). I controlled the CO\textsubscript{2} injection and brine extraction rates in order to determine operational combinations and control the potential artesian brine extraction at the extraction well that can occur due to the increase in reservoir pressure from CO\textsubcript{2} injection.

The model is based on the conservation of mass equations, first law of thermodynamics, and patched Bernoulli, where the length of the well is divided into
discrete elements and the fluid enthalpy, pressure, temperature, density, and velocity are calculated at each end of the well element. For a well element, \( i \), of length \( \Delta z \) (m), of diameter \( D \) (m), with a friction factor, \( f \),

\[
h_i = h_{i-1} + g \cdot \Delta z
\]  
(8)

\[
P_{loss,i} = (f \cdot \frac{\Delta z}{D}) \cdot \frac{\rho_{i-1}}{2} \cdot |v_{i-1}| \cdot v_i
\]  
(9)

\[
P_{cum,i} = P_{cum,i-1} + P_{loss,i}
\]  
(10)

\[
P_i = P_{i-1} - g \cdot \Delta z \cdot \rho_{i-1} - P_{loss}
\]  
(11)

\[
v_i = \frac{\rho_{i-1}}{\rho_i} \cdot v_{i-1}
\]  
(12)

where \( h_i \) is the enthalpy (J/kg), \( \rho \) is the density (kg/m\(^3\)), \( v_i \) is the velocity (m/s), \( P_i \) is pressure (Pa), \( P_{loss,i} \) is the frictional pressure loss (Pa) in the fluid over the length of the well element, and \( P_{cum,i} \) is the total cumulative frictional pressure loss (Pa) in the fluid over the length of the well at a given point well increment. The calculations are conducted at the end of element \( i \), using the estimates at the end of the prior element \((i-1)\), as the input to element \( i \). I used the output from the reservoir simulation at each point in time as the initial condition for the beginning of the well element in the reservoir. For all well calculations, I assumed
the friction factor \( (f) \) to be 0.02 for a stainless-steel pipe used in corrosive environments and assigned 9.81 (m\(^2\)/s) for the acceleration due to gravity \((g)\).

To estimate the properties and states of the fluid at the end of each well element, I used a freely available, open-source routine (Coolprop) that uses Helmholtz-energy-explicit equations (Bell et al., 2014). These equations use Helmholtz energy, which is a thermodynamic potential that measures work obtained from a closed thermodynamic system at a constant temperature and volume, to describe the fluid at given values of temperature and density. If temperature and density are not provided, numerical solvers within the program determine these values provided other thermodynamic properties of the fluid (e.g. pressure and enthalpy). More specifically, I used pressure and temperature from the reservoir simulator (FEHM) and then used the enthalpy and pressure that are estimated from Eqs. (8-11) in order to estimate the fluid density and temperature at the end of the first well element. These estimates were then used in Eq. (12) to estimate the velocity of the fluid in the well element.
For CO₂ injection, I located a pump at the wellhead to estimate the states and properties that are necessary for the CO₂ to be injected. I assumed that the CO₂ arrived to the injection wellhead at 7.5 MPa and 25°C to calculate the enthalpy, density, and velocity of the fluid at the surface prior to pumping. I injected CO₂ at a constant injection temperature of 65°C and used the downhole pressure from the FEHM models to estimate the enthalpy of the CO₂ at the top of the wellhead using the well model (Eqs. 8-12). The change in enthalpy before and after the pump, state 1 \((h_1)\) and 2 \((h_2)\) in Figure 5, is used with the assigned mass flow rate \((\dot{m})\) and a pump efficiency \((\eta)\) of 0.9 to calculate the pumping power \((W)\) needed to inject CO₂ into the reservoir, based on the mass flow rate (Eq. 13).
For brine extraction, I set the properties of the brine at the extraction wellhead to 50 kPa above saturation pressure, or 0.15 MPa for 100°C brine, to avoid flashing. Flashing can occur if the fluid pressure decreases below the saturation pressure and the fluid thus changes state to a vapor. To reduce the potential for flashing in the wellbore before the brine reaches the surface, I located the downhole pump 500 m below the surface, which is the maximum depth for present technology (Adams et al., 2015). The properties of brine in the extraction well are calculated in a similar way as the CO$_2$ injection well. The results from the reservoir simulation for the element at the inlet to the extraction well, location 4 in Figure 5, are used as the initial conditions for the well model in Eqs. 8-12. These equations are applied for the portion of the well between the reservoir and the downhole pump. Separate calculations applied the well model to the portion of the well between the wellhead and the downhole pump, locations 6 and 7 in Figure 5. The enthalpies that are calculated from each of these portions of the well are used in Eq. 13 to calculate the necessary pumping power for brine extraction.

2.3 Case Study: Rock Springs Uplift

The Rock Springs Uplift (RSU) formation in southwest Wyoming has been previously classified as a candidate for CO$_2$ storage due to (1) its ability to trap fluid, (2) relatively thick reservoir with enough storage capacity to facilitate injection, (3) sealing unit or impermeable confining unit above and below the desired injection reservoir, and

\[
W = \frac{m(h_2 - h_1)}{\eta} \quad (13)
\]
reservoir conditions such as temperature, pressure, and chemistry between rock and fluid that facilitates large CO$_2$ storage without damage (Surdam and Jiao, 2007).

Figure 6: Cross-Section of the Rock Springs Uplift from East to West. The Madison Limestone formation is indicated in blue and is the target of this research.

The RSU is a doubly-plunging anticline within an area approximately 50 miles by 35 miles. The formation is a prospect for CO$_2$ storage due to the folds and more than 10,000 feet of closed structural relief to contain the buoyant CO$_2$ (Surdam et al., 2013a; Surdam and Jiao, 2007). Figure 6 shows a schematic of the cross section from east to west of the RSU formation to visualize the formation structure and layers (Deng et al., 2012). Prior work has thoroughly characterized the RSU with an exploratory well and geophysical surveys, both of which provided geospatially resolved data on the heterogeneous permeability and porosity fields (Surdam et al., 2013b). The exploratory well identified sixteen units in the RSU. Appendix A includes a Phase I well schematic documenting the
formation units conducted by Baker Hughes and the University of Wyoming and documented in Surdam’s 2013 Final Report to the U.S. Department of Energy titled, “Site characterization of the highest-priority geologic formations for CO₂ storage in Wyoming” (Surdam et al., 2013a).

These studies identified the Weber Sandstone (thickness greater than 200 m) and the Madison Limestone (thickness greater than 75 m) as prospective intervals for CO₂ injection. The high average porosity and permeability led to initial CO₂ storage estimates of 18 billion tons for the Weber reservoir and 8 billion tons for the Madison reservoir (Surdam and Jiao, 2007). Other work has used these data for simulations of CO₂ injection for storage (Deng et al., 2012; Harp et al., 2017). I focused on the Lower Madison as the target reservoir for CO₂ emplacement at a depth between 3,709 m and 3,820 m, which ensures that the CO₂ will be supercritical at reservoir conditions (Surdam et al., 2013b).

In this work, the injection well is located approximately 55 km east of the town of Rock Springs, Wyoming and 3 km southeast of the 2.4 GW Jim Bridger coal-fired power plant (Surdam et al., 2013b; U.S. Environmental Protection Agency, 2014). The Jim Bridger’s Power Plant is a major source of anthropogenic CO₂; it emitted 14.8 MtCO₂ in 2014, which makes it an excellent case study to co-locate a CO₂-EWR system (U.S. Environmental Protection Agency, 2014).

To model the formation, I used a three-dimensional mesh of a 6 km x 6 km portion of the RSU that was developed with the Los Alamos Grid Toolbox (LaGriT; http://lagrit.lanl.gov). The mesh for the reservoir model includes the Darby, Lower Madison, Upper Madison, Amsden, and Weber with depths between 2.8 km and 4.3 km. The horizontal elements of the mesh are 67 m on a side, with a vertical scale of 8.6 m. The
values for porosity and permeability in each element of the Lower Madison are assigned with the prior data measured with a 3-D seismic survey from a test well (Surdam et al., 2013b, 2009; Surdam and Jiao, 2007). I assigned a constant porosity of 0.01 and permeability of $1 \times 10^{-18}$ m$^2$ throughout the remaining layers including the Upper Madison, which simulates the impervious formation that serves as the overlying caprock, and the Darby, which is the impervious formation underlying the Lower Madison (Surdam et al., 2013b).
Figure 7: Average Permeability through the 86 m Thickness of the Lower Madison CO$_2$ Storage Reservoir. The locations of the CO$_2$ injection well, the brine extraction well, and Jim Bridger’s fault line are indicated. The lateral extents of the modeled domain and the Jim Bridger’s fault line are modeled as closed boundaries to indicate compartmentalization within the prospective CO$_2$ storage reservoir.

Figure 7 shows the average permeability in the mesh for the Lower Madison CO$_2$ storage reservoir. The CO$_2$ injection well is located in the center of the modeled domain, and the brine extraction well is approximately halfway between the CO$_2$ injection well and the Jim Bridger’s fault line, which is approximately 3 km to the northeast of the CO$_2$ injection well. The case study modeled the injection and extraction wells with the same structural dimensions including a well diameter of 0.41 m at a total depth of 3,700 m and
incremental well elements of 100 m used within the well model. A frictional factor of 0.02 and pump efficiency of 0.9 is also used within the case study.

2.4 Injection and Extraction Scenarios

I conducted twenty simulations using various combinations of CO$_2$ injection rates and brine extraction rates. For CO$_2$ injection, I simulated constant injection of 4 kgCO$_2$/s, 8 kgCO$_2$/s, 16 kg CO$_2$/s and 32 kg CO$_2$/s. The highest rate, 32 kg CO$_2$/s, is approximately 1 MtCO$_2$ /yr and is at the high end of feasible injection rates that were modeled in prior work such as the Sleipner site, located under the North Sea off the Norway coast (Celia et al., 2015). I simulated brine extraction at a hypothetical well roughly halfway between the CO$_2$ injection well and the Jim Bridger’s fault, which located the brine extract well approximately 1,042m northeast of the CO$_2$ injection well (see Figure 7). I determined the brine extraction rates that are the volume-equivalents of the CO$_2$ injection rates at reservoir conditions (5.6 kgBrine/s, 11 kg Brine/s, 21.5 kg Brine/s, and 41 kg Brine/s), and simulated each combination of CO$_2$ injection rate and brine extraction rate. Simulations of CO$_2$ injection at each mass flowrate with no brine extraction serve as base cases to determine the effect of brine extraction on the performance of the reservoir for CO$_2$ storage.
Chapter 3: Results

The results of the various combinations of simulated scenarios for CO2 injection and brine extraction indicated the importance of tradeoffs within the reservoir such as the balance of pressure and the potential implications for the feasibility of each scenario. The below sections discuss the results for these various combinations of CO2 injection and brine extraction in terms of reservoir pressure, AoR, storage capacity potential, and the energy demand of pumping CO2 into and brine from the reservoir.

3.1 Reservoir Pressure

Prior to CO2 injection, the Lower Madison reservoir pressure is measured at 37.1 MPa based on the 3-D seismic survey data. This reservoir pressure increases during the simulation while CO2 is emplaced in the reservoir, with the maximum overpressure occurring at the point of CO2 injection. Brine extraction offsets this increase in overpressure if the CO2 injection rate is less than the volume-equivalent brine extraction rate. For example, Figure 8 shows the results of simulations where 16 kgCO2/s is injected; overpressure at the injection well increases over time if the brine extraction rate is \( \leq 11 \) kgbrine/s, but for the higher brine extraction rates I simulated, the reservoir pressure stays relatively constant or decreases. For the 21.5 kgbrine/s extraction rate that is the volume equivalent of the 16 kgCO2/s injection rate, the reservoir pressure is relatively constant at the injection well (39.5 MPa) and at the extraction well (30.6 MPa). For the higher 41 kgbrine/s extraction rate, the reservoir pressure decreases over time because the volume extraction rate of brine is greater than the volume injection rate of CO2.
Figure 8: Pressure in the Lower Madison due to CO$_2$ Injection of 16 kg CO$_2$/s. (a) Outlet of the CO$_2$ injection well, and (b) Inlet of the brine extraction well.
The results in Figure 8 also imply that brine extraction increases the rate at which emplaced CO\(_2\) migrates to the brine extraction well. The results are plotted until CO\(_2\) starts to be produced from the brine extraction well, which is known as CO\(_2\) breakthrough. I defined breakthrough when the CO\(_2\) saturation at the extraction well reaches 0.009. For example, for the constant 16 kgCO\(_2\)/s injection rate in Figure 8, CO\(_2\) breaks through the extraction well at 14.5 yrs for the 5.6 kg\(_{\text{brine}}\)/s extraction rate and 8.5 years for the 11 kg\(_{\text{brine}}\)/s. Holding everything else constant, the time until breakthrough decreases as the brine extraction rate increases. Figure 9 indicates the breakthrough time for each modeled scenario.

Overpressure can also limit the simulated scenario as the pressure increases to a point in which the integrity of the caprock is compromised. This fracture pressure, which is the pressure that could potentially induce fractures in the rock, is measured through the fracture gradient, and is a function of the well depth. The fracture gradient for the RSU is approximately 13.6 kPa/m (0.6 psi/ft) estimated by the Carbon Management Institution. With an initial pressure of 37.1 MPa at the CO\(_2\) injection well, the caprock fracture pressure is approximately 90 MPa. The reservoir pressure should stay below this limit and the rule of thumb is that this fracture gradient should only reach approximately 80% of this limit. Only one scenario exceeded the caprock fracture pressure. The scenario with 32 kg/s of CO\(_2\) injection with no brine extraction reached a pressure high of 122 MPa after 20 years of operation, which indicates that this simulation is an infeasible scenario for the RSU Lower Madison formation.
Figure 9: Total CO$_2$ Injected (yellow) and Brine Extracted (blue) until CO$_2$ Breakthrough or Completion of the 20 Year Simulation. The time until breakthrough is labeled at the top of the bars.

Figure 9 shows the total mass of CO$_2$ that is injected into, and the total mass of brine that is extracted from, the Lower Madison as well as the breakthrough time for each combination of CO$_2$ injection and brine extraction that I simulated. These results are also provided in Appendix B Table 1. In these combinations, CO$_2$ does not break through the extraction well before the end of the 20-year simulation if there is no brine extraction; there is also one combination where the CO$_2$ does not break through the extraction well before the end of the simulation (4 kgCO$_2$/s with 5.6 kg$_{\text{brine}}$/s). Breakthrough occurs in all of the other combinations of CO$_2$ injection and brine extraction and the time until breakthrough...
generally increases as the CO\textsubscript{2} injection rate increases or as the brine extraction rate increases.

Across all of the combinations where CO\textsubscript{2} breaks through the extraction well, the amount of brine that is extracted from the Lower Madison ranges between 1.8 and 4.5 Mt\textsubscript{brine}, and is thus relatively constant. This result occurs because there is a fixed pore volume in the reservoir, between the CO\textsubscript{2} injection well and the brine extraction well, from which brine could be extracted. Variations from this amount of brine that is extracted, and the CO\textsubscript{2} that is injected, result from the different combinations of CO\textsubscript{2} injection and brine extraction. Holding everything else constant, the amount of brine that is extracted from the extraction well should increase with the brine extraction rate, but this increase will be mitigated by how brine extraction pulls CO\textsubscript{2} through the reservoir to the extraction well. Similarly, holding everything else constant, higher CO\textsubscript{2} injection rates will displace brine from a pore volume that extends farther laterally outward from the region between the CO\textsubscript{2} injection well and the brine extraction well, but the higher injection rate also causes CO\textsubscript{2} to migrate more quickly toward the brine extraction well. As a result, there is a complicated relationship between the CO\textsubscript{2} injection rate and the brine extraction rate that determines how much CO\textsubscript{2} can be emplaced before CO\textsubscript{2} breakthrough, and this amount of CO\textsubscript{2} can be approximately represented by the extent of the CO\textsubscript{2} plume, which I defined as the area where the CO\textsubscript{2} saturation is > 0.009 or the Area of Review (AoR).

3.2 Area of Review (AoR)

Figure 10 shows the AoR for all combinations of brine extraction with a 16 kgCO\textsubscript{2}/s injection rate. The panels in Figure 10(a) show the extent of the AoR when CO\textsubscript{2} breaks
through the extraction well (5.6 kg_{brine}/s, 11.0 kg_{brine}/s, and 21.5 kg_{brine}/s) or at the end of the twenty-year simulation (no brine extraction).
Figure 10: Areas of Review (AoR) for 16 kg/s of CO₂ injection Until CO₂ Breakthrough or the End of the 20-Year Simulation. (a) CO₂ saturation (b) Evolution of the AoR.
In the upper left panel of Figure 10(a), the AoR is largest when there is no brine extraction in part because CO$_2$ does not break through during the twenty-year simulation. With the CO$_2$ injection rate held constant, this lack of breakthrough facilitates the emplacement of more CO$_2$ than when CO$_2$ breaks through the extraction well. This panel also shows the effect of the permeability changes in the well. The AoR is flatter and less circular in the region that is closest to the Jim Bridger’s fault line because the permeability is lower in this region (Figure 7). Brine extraction increases the ability of CO$_2$ to flow in the low permeability regions. Such a well placement can encourage CO$_2$ storage in regions with lower permeability and extend the usable space of a reservoir formation with heterogeneous permeability.

With brine extraction, the AoR shifts toward the brine extraction well and elongates as the CO$_2$ is pulled toward the brine extraction well. The AoRs in Figure 10(a) decrease in size at larger brine extraction rates, in part because of the earlier breakthrough time. Figure 10(b) shows the temporal evolution of the AoRs in Figure 10(a). In the early years of each of the brine extraction rates, the AoR is larger with brine extraction than with no brine extraction. Over time, the AoRs with brine extraction approach, and occasionally become less than the AoR with no brine extraction. These results indicate that early in the operation, no brine extraction scenarios could be more favorable than scenarios without brine extraction. The results in Figure 10(b) are consistent for the CO$_2$ injection scenarios with 32 kg/s, 8 kg/s, and 4 kg/s maintaining a trend in the evolution of CO$_2$ plume as CO$_2$ injection and brine extraction rates change.

Figure 11 shows the total AoR for the twenty simulated scenarios of various CO$_2$ injection and brine extraction at the end of the twenty-year simulation or when CO$_2$ breaks
through the extraction well. The AoR is larger with higher CO₂ injection rates (etc. 16 kg/s or 32 kg/s) without brine production, none of which experience CO₂ breakthrough prior to the twenty-year simulation period. In order to compare the change in AoR due to brine extraction, the scenarios have to hold CO₂ injection rate and simulation time constant. Due to varying CO₂ breakthrough times, only two scenarios can be evenly compared, the scenario with 4 kgCO₂/s injection and volume-equivalent 5.6 kg brine/s brine extraction rate and the scenario with 4 kgCO₂/s injection without brine extraction. Both of these combinations reached the end of the twenty-year simulation without breakthrough. For the scenario with brine extraction, the AoR is approximately 9.1% larger with brine extraction than without brine extraction. This could be due to the initial elongation of the CO₂ plume towards the brine extraction rate, which results in a greater AoR initially. Since breakthrough does not occur, the brine extraction scenario maintains a larger AoR. If simulated for a longer operational time and breakthrough occurs, the AoR for this scenario could near a similar AoR to the scenario without brine extraction. This combination is consistent with the trend of the other CO₂ injection and brine extraction combinations where the AoR with brine production is greater than the AoR without brine production in the early years but is similar or smaller in the later years near breakthrough.
Figure 11: Area of Review (AoR) After Twenty Years of Simulated CO₂ Injection and Brine Extraction, or until CO₂ Breaks Through the Extraction Well.

As the total volume of extracted brine expands, it is harder for the mass of brine further from the well to travel to the extraction well while the void of pore space facilitates the movement of CO₂ towards the extraction well. The AoR or the extent of the CO₂ plume, as it reaches the extraction well and induces breakthrough, moderates the small variability in mass due to magnitude of injection and extraction rates that are observed in Figure 9. The results for AoR shown in Figure 10 and Figure 11, suggest the importance in monitoring the AoR during the entire CO₂-EWR operation in order to provide context for the potential monitoring costs for particular CO₂ injection and brine extraction scenarios.
3.3 Normalized CO₂ Storage Rate

With a set mass injection and extraction rate, CO₂ storage is compared in terms of the reservoir overpressure (Figure 12). The extraction of brine reduces overpressure indicating more CO₂ storage capacity is possible per unit of overpressure when brine is extracted.
Figure 12: Mass of CO$_2$ Injected Relative to the Overpressure of the Lower Madison Formation. Comparison for (a) 32 kgCO$_2$/s and (b) 8 kgCO$_2$/s scenarios.
Higher extraction rates such as 32 kgCO$_2$/s increase the CO$_2$ injected per unit of overpressure (Figure 12a) and indicates a higher affinity for CO$_2$ storage. A balance of pressure within the CO$_2$-EWR system is critical because higher brine extraction rates can draw down the pressure too much, eliminating the benefit of increased storage. Figure 12b shows scenarios with 8 kgCO$_2$/s when pressure, within the reservoir, dips below the initial hydrostatic pressure for high brine extraction scenarios. The change in pressure above or below hydrostatic is an important indicator for potential issues including the flashing of brine within the extraction well due to too low of pressure. In order to maintain a relatively constant pressure within the reservoir if pressure is reduced too much, CO$_2$ injection rate should be increased, brine extraction rate decreased, or the reservoir should essentially charge the pressure of the reservoir with CO$_2$ injection initially followed by delayed brine extraction to maintain pressure above hydrostatic. This shows the CO$_2$ storage tradeoff between the use of brine extraction to relieve pressure buildup while attempting to delay breakthrough and reduce the time of operation.

3.4 Energy Analysis

CO$_2$ injection and brine extraction rates are controlled within the well model through pumps. The pumps increase the pressure in order to inject CO$_2$ or extract brine. This necessary change in pressure is used to estimate the power needed to inject CO$_2$ into, or extract brine from, the reservoir over time with the well model. The power demand of these pumps is impacted by the balance of pressure within the reservoir. For all scenarios, the initial spike in power is due to the time delay of the reservoir in acclimating to simultaneous injection and extraction. Additionally, as observed in Figure 8, the exclusion
of brine extraction drives a constant increase in the reservoir pressure resulting in higher pumping power demand. Since power depends on the pressure change of the reservoir, the increased pressure of the reservoir indicated an increase of the required power to inject CO₂, yet power results for CO₂ are not consistent with this logic. This is due to the properties of liquid CO₂ and manner in which I calculate enthalpy. Enthalpy is influenced by the internal energy of a fluid, volume, and pressure (Eq. 14),

\[ h = u + Pv \]  \hspace{1cm} (14)

where \( h \) is the enthalpy (J), \( u \) is the internal energy (J), \( P \) is pressure (Pa), and \( v \) is the volume (m³). Results for low CO₂ injection rates (e.g. 4 kgCO₂/s and 8 kgCO₂/s) at a constant injection temperature showed the CO₂ volume decreased faster than the pressure increased. Figure 13 shows the pumping power for scenarios with CO₂ injection of 4 kgCO₂/s. The enthalpy decreased for higher pressure scenarios, such as no brine extraction, due to the liquid properties of CO₂ which reduced the volume of the CO₂ in the reservoir and the resulting power needed for injection. This is only typically for CO₂ injection. Water is an incompressible fluid and thus does not behave in the same manner as CO₂ within the reservoir, wells, and pumps. For the brine extraction well, pressure above hydrostatic pressure of the reservoir can help push the brine to the surface while pressure below hydrostatic pressure of the reservoir can hinder brine extraction because of flashing that can occur in the well prior to the surface.
Figure 13: Power to Inject CO$_2$ and Extract Brine in the Lower Madison Formation of the Rock Springs Uplift for Scenarios with 4 kgCO$_2$/s Injection. Brine extraction is only feasible for the scenario with volume equivalent CO$_2$ injection.
For higher mass flow rates of CO\textsubscript{2} injection (e.g. 16 kg/s and 32 kg/s), enthalpy does not always decrease. Figure 14 shows the CO\textsubscript{2} injection and brine extraction pumping power for scenarios with 32 kgCO\textsubscript{2}/s of CO\textsubscript{2} injection. Unlike the lower CO\textsubscript{2} injection rate presented in Figure 13, the pumping power becomes higher for scenarios with less pressure relief due to brine extraction after approximately three years of operation. For the higher CO\textsubscript{2} mass injection rates (16 kg/s and 32 kg/s), the pressure increase within the reservoir impacts the enthalpy of the fluid more than the decreasing volume resulting in an increase in enthalpy. This increase in enthalpy required an increase in pumping power after three years of operation, resulting in higher power demands overall for scenarios with larger pressure increases within the reservoir. For volume equivalent scenarios, in which pressure is maintained, pumping power is fairly consistent for all simulated scenarios regardless of high or low mass flow rates. This is important because it shows the benefit of reduced pumping power needed for CO\textsubscript{2} injection due to brine extraction. It also shows the time delay of reduced pumping power, which could impact the time value of money. Since future costs are discounted more than costs in the present, scenarios with brine extraction have higher initial costs for the first three years.

The pumping power for the extraction well is in contrast to CO\textsubscript{2} injection requirement for pumping power (Figure 14b). An increase in reservoir hydrostatic pressure resulted in an increase in pressure at the extraction well and reduced the pumping power needed for brine extraction. As brine extraction rates increased, the pressure is drawn down at the well, which hindered the benefit added to the extraction pumping requirement when reservoir pressure increases (Figure 14b). This resulted in a tradeoff between the benefit of
higher brine extraction to reduce the power for CO$_2$ injection and the added power needed for the higher brine extraction rate.
Figure 14: Power to Inject CO\textsubscript{2} and Extract Brine in the Lower Madison Formation of the Rock Springs Uplift. (a) Pumping power to inject CO\textsubscript{2} and (b) extract brine for 32 kgCO\textsubscript{2}/s injected.
Infeasible scenarios occurred when modeling the brine extraction well. Typically brine extraction scenarios above the volume equivalent CO₂ injection rate, significantly decreased the pressure in the system to the extent that the downhole pump cannot extract brine and flashing occurred in the well prior to the surface. Figure 13 shows the only brine extraction rate feasible for 4 kgCO₂/s is the volume equivalent scenario with 5.6 kg brine/s extraction. For the scenarios with 32 kgCO₂/s injected, pressure drawdown occurred during the volume equivalent scenario of 41 kg brine/s similarly resulting in its infeasibility.

To convert the pumping power of CO₂ injection and brine extraction to a form in which I can assign a cost, pumping power was integrated over time to calculate the total energy required to pump or extract from the reservoir. Since the twenty simulated scenarios each encounter CO₂ breakthrough at various points in time during operation, the total energy is normalized by the total mass of CO₂ injected or extracted. Figure 15 shows the total mass of CO₂ injected normalized by the energy required to inject CO₂ into the reservoir and the total mass of brine extracted normalized by the energy required to extract brine from the reservoir.
Figure 15: Total Mass of CO\(_2\) Injected (orange) or Brine Extracted (blue) Normalized by the Required Energy to Pump CO\(_2\) into or Brine from the Reservoir. Infeasible solutions are shown in gray and only represent the mass of CO\(_2\) injected per the energy required for CO\(_2\) injection. These infeasible scenarios include scenarios with significant pressure drawdown preventing brine extraction and for the scenario with 32 kgCO\(_2\)/s of CO\(_2\) injection and no brine extraction scenarios that exceeds the fracture gradient indicating potential caprock failure.

The total energy is influenced by the time of CO\(_2\) breakthrough, the properties of CO\(_2\) in the reservoir, and the pumping power requirement. Premature breakthrough impacted the duration of pumping operations and resulted in decreased time to facilitate CO\(_2\) storage thus reducing the energy demand for the modeled scenario. Comparing the energy requirements to the mass of CO\(_2\) injected or brine extracted minimized the impact of breakthrough in order to compare energy requirements for all twenty simulated scenarios. Results indicated that the mass of CO\(_2\) stored normalized by the energy to inject
the CO₂ is relatively similar for all twenty scenarios, and actually decreased with the addition of brine extraction for scenarios with 4 kgCO₂/s, 8 kgCO₂/s and 16 kgCO₂/s. With constant mass injection rates, the reduction of the ratio of mass to energy demand showed that energy for higher brine extraction rates increased, which is consistent with Figure 13a. Scenarios with 32 kgCO₂/s are relatively similar and more consistent with the reduction of pumping power for scenarios with higher brine extraction rates as seen in Figure 14a. This is due to the change in fluid properties of CO₂ between low and high injection mass flow rates. The major differences in total pumping power is mainly attributed to the changes of mass of brine extracted relative to the energy required to extract the brine. Higher energy requirements are needed for higher brine extraction rates regardless of the mass flow rate (Figure 13b and Figure 14b), which is due to the reduction of pressure in the reservoir with higher brine extraction rates (Figure 8).

Since I am focusing on the value of CO₂ stored and the energy required for CO₂ storage, I also compared the mass of CO₂ injected relative to the total energy of the system in Figure 16.
Figure 16: Comparison of (a) Total CO₂ Injected, (b) Total Energy to Inject CO₂ and Extract brine, and (c) the Ratio of CO₂ Mass Injected per Unit of Total Energy to Inject CO₂ and Extract brine. Infeasible solutions are shown in gray and include scenarios with significant pressure drawdown preventing brine extraction and scenarios that exceed the fracture gradient indicating potential caprock failure.

The results of this comparison indicate that although more CO₂ can be stored with higher CO₂ injection rates and small rates of brine extraction, the energy requirement is...
significantly larger. In considering the combinations of CO₂ injection and brine extraction and the associated energy requirements, the use of brine extraction is less desirable because the scenarios that led to the most CO₂ stored generally required the most energy.
Chapter 4: Discussion

I modeled simultaneous CO\textsubscript{2} injection and brine extraction as a form of pressure management within the RSU Lower Madison formation and simulated this model for various combinations of CO\textsubscript{2} injection and brine extraction. The analysis of these simulations provided in-depth information about a CO\textsubscript{2}-EWR system within the RSU. The trends and tradeoffs identified can be used to describe the general behavior of a CO\textsubscript{2}-EWR system with the future objective of determining optimal combinations of CO\textsubscript{2} injection and brine extraction. Several relationships are identified that could be useful for further analysis on system optimization. Examples of these relationships include the tradeoff between the reservoir pressure buildup due to the injection of CO\textsubscript{2} and or pressure relief due to the extraction of brine, the influence of breakthrough time, CO\textsubscript{2} storage capabilities emplacement based on the rate of CO\textsubscript{2} injection and brine extraction, and the energy requirements based on the total mass of CO\textsubscript{2} stored.

4.1 Mass Flow Rate and Overpressure

The tradeoff between pressure increase due to CO\textsubscript{2} injection and the use of brine extraction to manage this pressure is an important component of a CO\textsubscript{2}-EWR system. Figure 8 shows the RSU case study results for pressure increase overtime at the injection and extraction wells for scenarios with a 16 kgCO\textsubscript{2}/s injection rate. Reservoir pressure increases with higher CO\textsubscript{2} mass flowrates and brine extraction mass flowrates can reduce this pressure increase. This reduction of pressure is favorable in reducing risks due to overpressure. The scenario with a 32 kgCO\textsubscript{2}/s injection and no brine extraction exceeded the fracture gradient as the pressure increased from a hydrostatic pressure of 37.1 MPa to
122 MPa. Large-scale implementation of CO$_2$ storage will need sufficient pressure management in order to increase feasibility of implementation and mitigate some of the potential problems associated with overpressure. Adding brine extraction to this scenario decreased the reservoir pressure to 80 MPa and within the fracture pressure of 90 MPa. Volume-equivalent brine extraction rates essentially stabilized the pressure within the reservoir near the initial hydrostatic pressure. This stabilization can facilitate more storage if the reservoir has sufficient capacity and CO$_2$ does not break through the extraction well.

The overpressure in this model also impacted the capacity to store CO$_2$. Normalizing the mass of CO$_2$ stored relative to the overpressure demonstrated that the removal of brine from the reservoir indicated higher potential for CO$_2$ storage per unit of overpressure (Figure 12). Reducing the pressure too much through higher extraction rates paired with lower CO$_2$ injection rates resulted in infeasible scenarios as pressure reduction below hydrostatic conditions in some scenarios obstructed brine removal from the reservoir. The well model demonstrated that for these scenarios the reservoir did not have enough pressure to travel the length of the well to the location of the downhole pump or the liquid changed phases indicating that flashing occurred somewhere in the well prior to the surface.

There is a balance between overpressure and sufficient pressure in the reservoir to maintain a functioning CO$_2$-EWR system. These results show that brine extraction is beneficial in reducing the overpressure in the reservoir, but can also become limiting as pressure can be reduced to a point of infeasibility of the system to extract brine. Due to the pressure tradeoffs, there should be strategies in the selection of CO$_2$ injection and brine extraction rates. These strategies could include changing the deployment of brine
extraction in order to maintain a pressure high enough at or above hydrostatic but below caprock fracture pressures, which could include delaying brine extraction until reservoir pressure reaches a pressure above the threshold needed to extract brine and then maintain the pressure of the reservoir. Future investigations could also actively adjust injection and extraction rates in order to optimize CO$_2$ storage and maintain pressure within a designated optimal region.

4.2 Breakthrough Time Influences

Operational time influences the total mass of CO$_2$ injected, total mass of brine extracted, AoR, pumping power for the injection and extraction wells, and the resulting energy requirement from pumping. This research sets the total time of operation for twenty years, yet CO$_2$ breakthrough at the brine extraction well occurs for many of the simulated scenarios affectingly ending the operational time early. This time is dictated by the growth and direction of the CO$_2$ plume towards the brine extraction well. Ending the CO$_2$-EWR operation prematurely interrupts the injection of CO$_2$ and the storage capabilities of the reservoir, which reduces the overall power and energy requirement over time.

The CO$_2$ plume within the subsurface is influenced by the rate of CO$_2$ injection along with the rate of brine extraction. Increasing the CO$_2$ injection mass flow rates increased the mass needed to store, while increasing the removal of brine changed the plume direction and shape within the reservoir, which is observable through the AoR as the CO$_2$ plume is pulled towards the extraction well elongating the shape of the plume (Figure 10). Increasing the mass of extracted brine facilitates more space for CO$_2$ storage, while simultaneously pulling the CO$_2$ towards the extraction well and encouraging early
CO₂ breakthrough at the well. The push of CO₂ injection and pull of brine extraction managed the direction of the CO₂ plume as well as the speed in which breakthrough occurs at the extraction well. This shows the tradeoff between the use of brine extraction to relieve overpressure while attempting to delay breakthrough and increase operational time to store more CO₂.

Since CO₂ breakthrough at the brine extraction well reduces the effectiveness of brine extraction, it may be necessary to stage multiple brine extraction wells. Multiple extraction wells allow shut-in after breakthrough while an extraction well that is farther away from the CO₂ injection well becomes operational in order to extend the operational time and reduce the impact of premature breakthrough on the total storage of CO₂. A multiple extraction well approach for reservoir modeling has been previously studied and used as a potential pressure management technique (Buscheck et al., 2016a; Harp et al., 2017). Overall, these results suggest the need for sophisticated injection and extraction strategies. Ideal brine extraction rates increase the ability of CO₂ to flow within the reservoir and expand storage while extending the operational time. Results show adding extraction reduces the operational time due to breakthrough, but staged wells increase the time until breakthrough for these scenarios and alleviate this problem. This strategy could increase the benefits of higher injection rates with higher brine extraction rates to increase storage of CO₂ within the well and reduce early breakthrough issues.

4.3 Initial-Modeling Cost Indications

Energy and power is incorporated into this model in order to begin to assign value to the system. The reservoir model provided the intricate nature of the twenty simulated
scenarios in terms of pressure, plume development, and capacities at breakthrough within the reservoir. The pumping power, calculated with the well model, is stimulated by these characteristics which in turn change the total energy of the CO2-EWR system. These changes include the impacts of pressure increases or decreases within the reservoir and the resulting changes in energy to pump CO2 into the reservoir or extract brine from the reservoir. Assigning costs to the energy can determine an appropriate value to assign for a CO2 tax or for treated water in order to make the CO2-EWR a cost-efficient system. In considering the combinations of CO2 injection and brine extraction scenarios, energy requirements showed that brine extraction is less desirable because the scenarios that lead to the most CO2 stored, high CO2 injection rates with low brine extraction rates, generally require the most energy for the pumps (Figure 16). Although the pumping costs are just a portion of total costs for operation, the costs of pumping appear to outweigh the benefits of CO2 storage and indicate CO2 storage without brine extraction stores more CO2 per unit of energy needed to inject CO2 and extract brine. Additional costs to consider in the future include CO2 capture, CO2-EWR facility costs, transportation of CO2 and brine, environmental monitoring, brine treatment, and brine concentrate disposal following treatment. The addition of treatment and brine concentrate disposal for simulated scenarios with brine extraction, will continue to contribute to the costs of brine extraction in CO2-EWR. As a result, the mass of CO2 stored will need to have a significant enough benefit, such as a high CO2 tax benefit, in order for the scenarios with high CO2 injection and storage to outweigh the added costs of brine extraction.

Simulated results can also provide indications of the cost value of CO2-EWR during the operation of the system. The AoR with brine extraction is larger compared to no brine
extraction scenarios prior to breakthrough for all of the simulated scenarios of CO₂ injection and brine extraction rate combinations (Figure 10b). The initially larger AoR with brine extraction has important implications for the timing of the costs with any positive discount rate; the time value of money works partly against brine extraction because costs are partly a function of the size of the AoR and costs in the future are discounted more than costs in the present. The initially higher pumping requirement for the first three years of operation for no or lower brine extraction rates for high CO₂ injection rates (32 kgCO₂/s) (Figure 14) is also impacted by the time value of money as it is more costly initially for the brine extraction scenarios. The operational timeline of CO₂-EWR system is also important in monitoring costs because early breakthrough effectively terminates the system’s operation which incur high costs in a short time period without enough time to allow benefits from CO₂ mitigation and beneficial use of the extracted brine to decrease the breakeven cost.

A cost analysis which integrates all of these considerations in terms of the benefits of higher storage compared to energy costs, the timing of CO₂ breakthrough, and timeline of high costs during the operational time of the system will be beneficial in determining the applicability of this type of system and the importance in choosing operational parameters.
Chapter 5: Future Work

5.1 Value of CO$_2$ Storage Relative to Brine Extraction

The combined reservoir and well modeling for simulations of various CO$_2$ injection and brine extraction combinations provided the basis for further analysis by assigning costs within the CO$_2$-EWR system such the price of energy to inject CO$_2$ or a potential tax value for CO$_2$ storage. The total energy of the system in terms of CO$_2$ injection and brine extraction facilitates the comparison of the net present value of CO$_2$ injected and stored compared to the net present value of brine extracted. This will determine the benefit needed through brine extraction in order to make CO$_2$-EWR profitable.

In order to compare the costs of the system, the total energy demand of the pumps for CO$_2$ injection and brine extraction will be discounted at an assigned interest rate, which adjusts the energy demand over different time periods to reflect the value of the demand in the current time period. A reasonably assumed electricity price ($/MWh) will calculate the present cost of CO$_2$ injection based on the energy demand. The Emergency Economic Stabilization Act in October of 2008 proposed a tax credit of $20 per metric ton for CO$_2$ captured at a qualified facility and disposed in a secure geologic storage facility (H.R. 1424, Emergency Economic Stabilization Act of 2008, 2008). I will investigate a set price of $20, $40, and $80 per metric ton of CO$_2$ stored within the CO$_2$-EWR system to calculate the present benefit of CO$_2$ storage. The set price of CO$_2$ stored is similarly discounted at the assumed interest rate. I will calculate the present benefit of brine extraction needed in order for the next present value of the CO$_2$-EWR facility to breakeven.
5.2 Cost Minimization Optimization

Assigned costs calculated from the energy requirements along with potential facility cost for operation, and brine treatment and disposal costs will drive a cost minimizing optimization model. The fixed cost of the operational CO$_2$-EWR system will be based on previously published literature, which focuses on relating the geologic heterogeneity to the costs and capacities of brine production (Heath et al., 2012; Kobos et al., 2011). The Integrated Environmental Control Model (http://www.cmu.edu/epp/iecm/) will also be used to estimate variable costs, energy requirements, and water usage for CO$_2$ capture. This model is based on data provided by U.S. EPA eGRID and U.S. EIA forms.

Brine treatment is highly dependent on water chemistry and the intended water end quality. The Water Treatment Model (WTM) developed by LANL is a system-level, mesoscale analysis module within the CO$_2$-Predicting Engineered Natural Systems (CO$_2$-PENS) model that analyzes the feasibility of brine extracted during CO$_2$-EWR operations (Sullivan et al., 2015, 2013, 2012). The only publicly available version of the WTM includes the cost of treatment, the value of energy recovery for specific treatment technology, and the cost of brine concentrate disposal. The treatment methods in the WTM only include single applications of reverse osmosis, nanofiltration, and thermal desalination. This modeled will be enhanced with literature treatment methods and costs. Ultimately, the potential costs of treating this water will be inputs to the cost minimization optimization to determine the value of CO$_2$-EWR operations provided the benefits of pressure control and increased CO$_2$ storage in the reservoir.
Reference


Feth, J.H. and O., 1965. Preliminary Map of the Conterminous United States Si-lowing Depth to and Quality of Shallowest Ground Water Containing More Than 1,000 Parts Per Million Dissolved Solids.


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Appendix A: RSU Formation Geological Layers through Well Schematic
Phase I well schematic conducted by Baker Hughes and the University of Wyoming and documented in Surdam’s 2013 Final Report to the U.S. Department of Energy titled, “Site characterization of the highest-priority geologic formations for CO₂ storage in Wyoming” (Surdam et al., 2013a)
Appendix B: Modeled Results Table
Table 1: Reservoir and Well Model Results for the Twenty Simulated Scenarios

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<th>CO₂ Injection (kg/s)</th>
<th>Brine Production (kg/s)</th>
<th>Breakthrough Time (y)</th>
<th>CO₂ Injection Pump (MWyr)</th>
<th>Brine Extraction Pump (MWyr)</th>
<th>Total Pump (MWyr)</th>
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