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Energy Procedia 63 (2014) 5333 – 5340
Energy Procedia

GHGT-12

Pre-Injection Brine Production for Managing Pressure in Compartmentalized CO_2 Storage Reservoirs

Thomas A. Buscheck[a], Joshua A. White[a], Mingjie Chen[a], Yunwei Sun[a], Yue Hao[a], Roger D. Aines[a], William L. Bourcier[a], and Jeffrey M. Bielicki[b,c]

[a]*Lawrence Livermore National Laboratory, Livermore, CA 94550, USA*
[b]*Department of Civil, Environmental, and Geodetic Engineering, The Ohio State University, Columbus, OH 43210, USA*
[c]*John Glenn School of Public Affairs, The Ohio State University, Columbus, OH 43210, USA*

Abstract

We present a reservoir management approach for geologic CO_2 storage that combines CO_2 injection with brine extraction. In our approach, *dual-mode* wells are initially used to extract formation brine and subsequently used to inject CO_2. These wells can also be used to monitor the subsurface during pre-injection brine extraction so that key data is acquired and analyzed prior to CO_2 injection. The relationship between pressure drawdown during pre-injection brine extraction and pressure buildup during CO_2 injection directly informs reservoir managers about CO_2 storage capacity. These data facilitate proactive reservoir management, and thus reduce costs and risks. The brine may be used directly as make-up brine for nearby reservoir operations; it can also be desalinated and/or treated for a variety of beneficial uses.

Peer-review under responsibility of the Organizing Committee of GHGT-12

Keywords: Reservoir management; geologic CO_2 storage; CO_2 utilization; brine production; brine utilization; desalination; monitoring wells

1. Introduction

Pressure buildup during industrial-scale CO_2 injection can limit storage capacity in saline formations. These overpressures can also cause CO_2 and displaced brine to leak into shallow freshwater aquifers [1,2,3], result in the loss of seal integrity, and induce seismicity [4]. Reservoir management should address several key needs in order to be effective for geologic CO_2 storage (GCS). The first need is to cost-effectively acquire the data necessary to inform reservoir management decisions in a timely manner. Establishing that a site is a suitable candidate for CO_2 storage—including minimizing the risk of CO_2 leakage—requires that sufficient data and information is acquired and analyzed prior to CO_2 injection. This assessment requires identifying a caprock that has sufficient seal integrity to contain the buoyant, pressurized CO_2 plume. A tight caprock seal also improves the efficiency of pore pressure reduction when extracting brine.

*Corresponding author. Tel: +1-925-423-9390; fax: +1-925-423-0153
E-mail address: buscheck1@llnl.gov

Peer-review under responsibility of the Organizing Committee of GHGT-12
doi:10.1016/j.egypro.2014.11.565

To be suitable for geologic CO_2 storage, a site must have sufficient storage capacity, which is a function of the candidate CO_2 storage zone(s) and their compartment volume(s). Further, CO_2 injection must be able to proceed without incurring too much pore overpressure. CO_2 storage capacity may be increased with a reservoir *pressure* management strategy that extracts brine from the CO_2 storage compartment. The brine may be used directly as make-up brine for nearby hydrocarbon and geothermal reservoir operations; it can be desalinated and/or treated for use in industrial, agricultural, and residential applications; and it may also be a source for valuable minerals, such as lithium.

Many CO_2 reservoir studies of pressure management use separate, *single-mode* CO_2-injection wells and brine-extraction wells [5,6,7,8,9,10,11,12,13,14,15] and the trade-off between early pressure relief and delayed CO_2 breakthrough has been identified as a key operational challenge. Early pressure relief requires close well spacing between the CO_2 injectors and brine producers, but delayed CO_2 breakthrough at brine producers requires large spacing [10]. Using separate injectors and producers requires good hydraulic communication between those wells, which cannot always be guaranteed. Many geologic formations are compartmentalized, such as the Tubåen Formation at the Snøhvit site [16,17], which can limit hydraulic communication between wells and reduce the direct benefit of extracting brine to relieve pressure at a CO_2 injector. Early CO_2 breakthrough may require that brine extraction at the affected wells be abandoned and additional brine-extraction wells be installed elsewhere. Overall, early CO_2 breakthrough and poor hydraulic communication between wells can increase capital and operating costs of reservoir management. Accordingly, cost-effective well-field operations—including cost-efficiency on a per-well basis and a per-mass-of-extracted-brine basis—are key needs that should be addressed by effective reservoir pressure management.

1.1. Pre-injection Brine Production: Motivation and Goals

The motivation for implementing pre-injection brine production with dual-mode wells is to provide timely, cost-effective information and pressure reduction where it is most needed: at the center of the CO_2 storage zone. Ultimate goals of this approach include:

- early (pre-injection) assessment of the suitability of candidate sites and identification of preferred storage zones
- better assurance that the integrity of the storage formation, and related environmental risk, can be managed
- increasing the volume of a candidate formation that is available for CO_2 storage
- the possibility that permitting authorities could consider the well during the pre-injection stage as a characterization well, providing additional reservoir information prior to the final Class VI injection permit decision, which can reduce technical and financial risks associated with the permitting process itself
- reducing overall project cost (including the cost of financial security to cover environmental risk)
- production of industrial quality water and/or minerals to generate economic value to defray project cost

1.2. Pre-injection Brine Production: Approach

Our approach starts with a dual-mode brine-extraction/CO_2-injection well, and possibly one or more deep pressure-monitoring wells. These wells are completed in the *candidate* target CO_2 storage zones and at above-zone monitoring locations (Fig. 1a). Initially, brine is extracted from each of the candidate zones, while the pressure response is monitored. (Note that in a multi-well field-development strategy, several *multi-purpose*, monitoring/brine-extraction/CO_2-injection wells may be phased in over the life of the field, to better leverage well-drilling costs.) The goal is to identify a target CO_2 storage zone that is overlain with a caprock seal that is tight enough to constrain the *upward* migration of buoyant CO_2 and to prevent the *downward* migration of brine during the pre-injection brine-extraction stage (Fig. 1a). Preventing this downward brine migration is important because a downward flux of brine into the target CO_2 storage zone would partially offset the benefits of extracting brine: to reduce pore pressure, and thus accommodate more CO_2 injection without much pore overpressure. Once a suitable target CO_2 storage zone is identified, additional brine extraction can continue until the pressure perturbation is able to inform reservoir managers about the hydrologic properties of the CO_2 storage reservoir. This approach is, effectively, an extended pressure drawdown test. The pressure response at the brine extraction well, together with the pressure response at the shallow monitoring well (Fig. 1a), can be used to estimate the effective compartment volume of the target CO_2 storage zone and the contribution of caprock leakage on pressure relief.

During the pre-injection brine-extraction stage, an ensemble of tracer slugs can be released in a second dual-mode well (the "deep monitoring well" in Fig. 1a). Tracking the arrival times of the respective tracer slugs at the brine-extraction well can help forecast when CO_2 breakthrough will occur during the CO_2 injection stage (Fig. 1c). Together with the pressure response, this information can help reservoir managers plan the timing and rates of CO_2 injection and brine extraction for the CO_2 injection stage (Figs. 1b and 1c).

Monitoring pressure and the migration of the CO_2 plume during the CO_2 injection stage provides useful information that may be used to locate a third dual-mode well that could be used for brine extraction (if CO_2 storage operations are extended). This process would involve moving CO_2 injection from the first to the second dual-mode well (Fig. 1d). Depending on the CO_2 storage requirements, this staged process can continue with additional dual-mode wells.

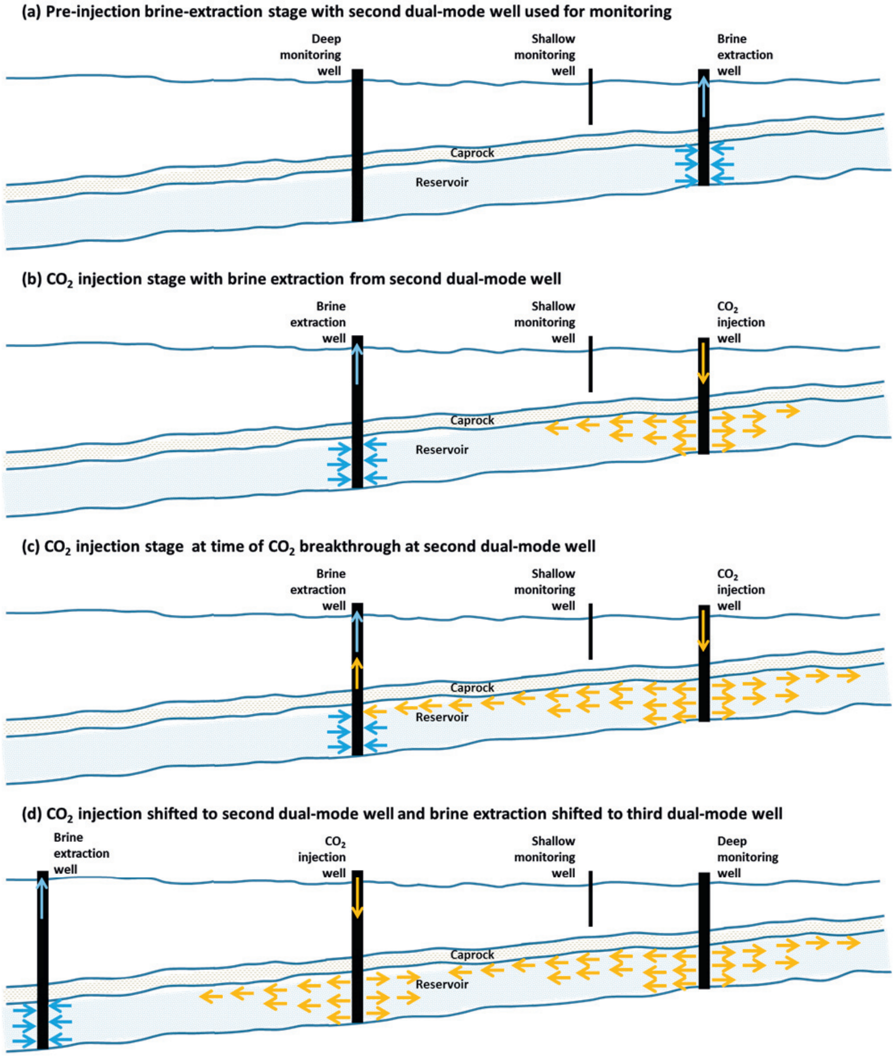


Fig. 1. Reservoir pressure management using *dual-mode* brine-extraction/CO_2-injection wells during (a) pre-injection brine-extraction stage, (b) CO_2 injection stage, with concurrent brine-extraction from the second dual-mode well, (c) CO_2 injection stage at the time of CO_2 breakthrough, and (d) optional CO_2 injection stage, with CO_2 injection shifted to the second dual-mode well and brine extraction shifted to the added (third) dual-mode well. A shallow monitoring well completed above the caprock is used to monitor pressure and assess seal integrity and the contribution of caprock leakage to pressure relief. The second and third dual-mode wells should be completed down-dip of the first dual-mode well to take advantage of gravity segregation, to delay CO_2 breakthrough.

2. Modeling Approach

We conduct reservoir analyses with the Nonisothermal Unsaturated Flow and Transport (NUFT) numerical simulator, which simulates multi-phase heat and mass flow and reactive transport in porous media [19, 20]. NUFT has been used extensively in GCS reservoir studies [2,3,9,10]. We investigate a pressure-management approach that can be implemented with an individual dual-mode brine-extraction/CO_2-injection well operating within a reservoir compartment. We consider a range of reservoir compartment permeability (50, 100, and 200 mD). We also consider a wide range of reservoir compartment area (1 to 300 km^2) and thickness (100 to 300 m). The reservoir compartment is vertically confined by (caprock and bedrock) seal units. For most cases, seal permeability is 0.001 mD, similar to that used in previous GCS studies [6,9,10,18,21]. We also consider seal permeabilities of 0.0001 and 0.002 mD. The reservoir is fully compartmentalized, bounded laterally by impermeable sealing faults. The storage reservoir is located at an average depth of 2250 m. The values of pore and water compressibility are 4.5×10^{-10} and 3.5×10^{-10} Pa^{-1}, respectively. Water density is determined by the ASME steam tables [22]. The two-phase flow of CO_2 and water was simulated with the density and compressibility of supercritical CO_2 determined by the correlation of Span and Wagner [23] and viscosity is given by the correlation of Fenghour et al. [24]. We inject CO_2 at a rate of 1 MT/yr for up to 300 years. A geothermal gradient of 37.5^{o}C/km results in an initial temperature of 101.3^{o}C at the bottom of the reservoir, assuming a mean annual surface temperature of 14.5^{o}C. The temperature of the injected CO_2 is 25^{o}C, at reservoir conditions.

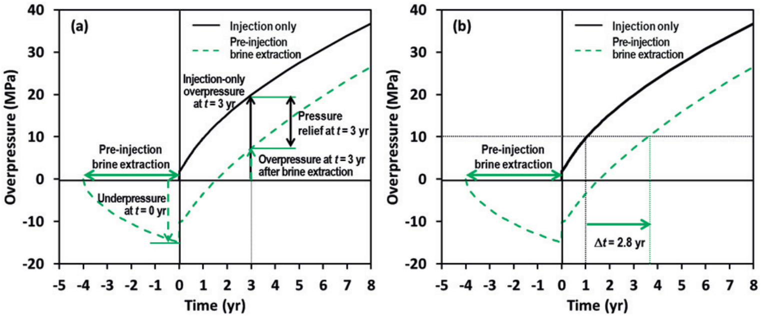
3. Results

We present results for a single dual-mode brine-extraction/CO_2-injection well operating at the center of a square reservoir compartment (Figs. 2 and 3). For all cases, CO_2 injection begins at t = 0 yr, at a constant rate of 1 MT/yr, which is small compared to industrial-scale CO_2 injection, which may on the order of 10 MT/yr. We consider compartment areas of 1 to 300 km^2 and compartment thicknesses of 100 to 300 m. Caprock thickness is 100 m. For all reservoir scenarios, brine is extracted for 4 years (from t = -4 to 0 yr) at a constant rate of 1 MT/yr; and a corresponding "injection-only" case is also considered for comparison purposes.

3.1. Relationship Between Pre-Injection Underpressure and Overpressure during the Injection Stage

We begin by looking at the influence of pre-injection brine extraction on pressure relief in a small reservoir compartment (Figs 2a and 2b). Underpressure is -15 MPa after 4 years of brine extraction, which is similar to the magnitude of overpressure ΔP (20 MPa) for the injection-only case at t = 3 yr. For injection-only, ΔP = 10 MPa is attained in 1 year, while 4 years of brine extraction extends that time to 3.8 years (Δt = 2.8 yr in Fig. 2b). Because the density of CO_2 is about 70 percent that of brine at reservoir pressure and temperature conditions, extracting brine at a rate of 1 MT/yr for 4 years is volumetrically equivalent to injecting CO_2 at a rate of 1 MT/yr for 2.8 years. Thus, for pressure buildup, 4 years of brine extraction achieves the same effect as delaying CO_2 injection for 2.8 years.

Fig. 3 plots the time required for dual-mode and single-mode wells to attain ΔP = 10 MPa for all reservoir compartment sizes and permeability values considered in this study. An overpressure of 10 MPa was selected because it is representative of a typical value of fracture overpressure. This value is similar to the fracture overpressure of 8 MPa estimated for the Tubåen Formation at Snøhvit [16,17]. For all cases, time to attain ΔP = 10 MPa is increased by 2.5 to 3 years as a result of extracting brine for 4 years prior to CO_2 injection. Time to attain ΔP = 10 MPa increases with reservoir compartment area and thickness (Fig. 3). For small compartments, time to ΔP = 10 MPa is proportional to reservoir compartment volume, indicating that it is controlled by compressibility. For large reservoir compartment areas, this time increases more than linearly with compartment area because of there being sufficient time for leakage through the caprock to influence pressure buildup and relief. A comparison of Figs. 3a, 3b, and 3c shows time to ΔP = 10 MPa is insensitive to reservoir permeability. However, time to ΔP = 10 MPa strongly depends on caprock permeability (Fig. 3d). For a caprock permeability of 0.0001 mD, caprock leakage does not contribute to pressure relief and time to ΔP = 10 MPa is entirely controlled by compressibility. For a caprock permeability of 0.001 mD, caprock leakage influences pressure relief for large compartment areas. Increasing caprock permeability from 0.001 to 0.002 mD strongly increases the contribution of caprock leakage on pressure relief (Fig. 3d).



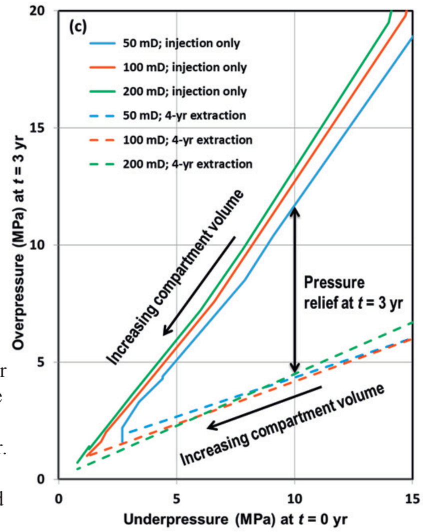


Fig. 2. (a) Overpressure ΔP history is plotted for a dual-model brine-extraction/CO_2-injection well and a single-mode CO_2-injection well for a reservoir compartment area of 1.6 km^2; reservoir thickness of 120 m; reservoir permeability of 100 mD; and seal permeability of 0.001 mD. Brine is extracted at a rate of 1 MT/yr for 4 years. CO_2 is injected at a rate of 1 MT/yr, starting at $t = 0$ yr. (b) Same as (a), showing how the time to attain an overpressure of 10 MPa is increased by 2.8 yr. (c) Overpressure three years into CO_2 *injection* stage is plotted as a function of underpressure (negative overpressure) after 4 years of pre-injection brine extraction (dashed lines). Also plotted is the overpressure for the corresponding cases with no brine extraction (solid lines). Reservoir permeability values of 50, 100, and 200 mD are considered. Caprock permeability is 0.001 mD. A wide range of reservoir compartment area (1 to 300 km^2) and thickness (100 to 300 m) are considered. The CO_2 injection rate and brine extraction rate is 1 MT/year.

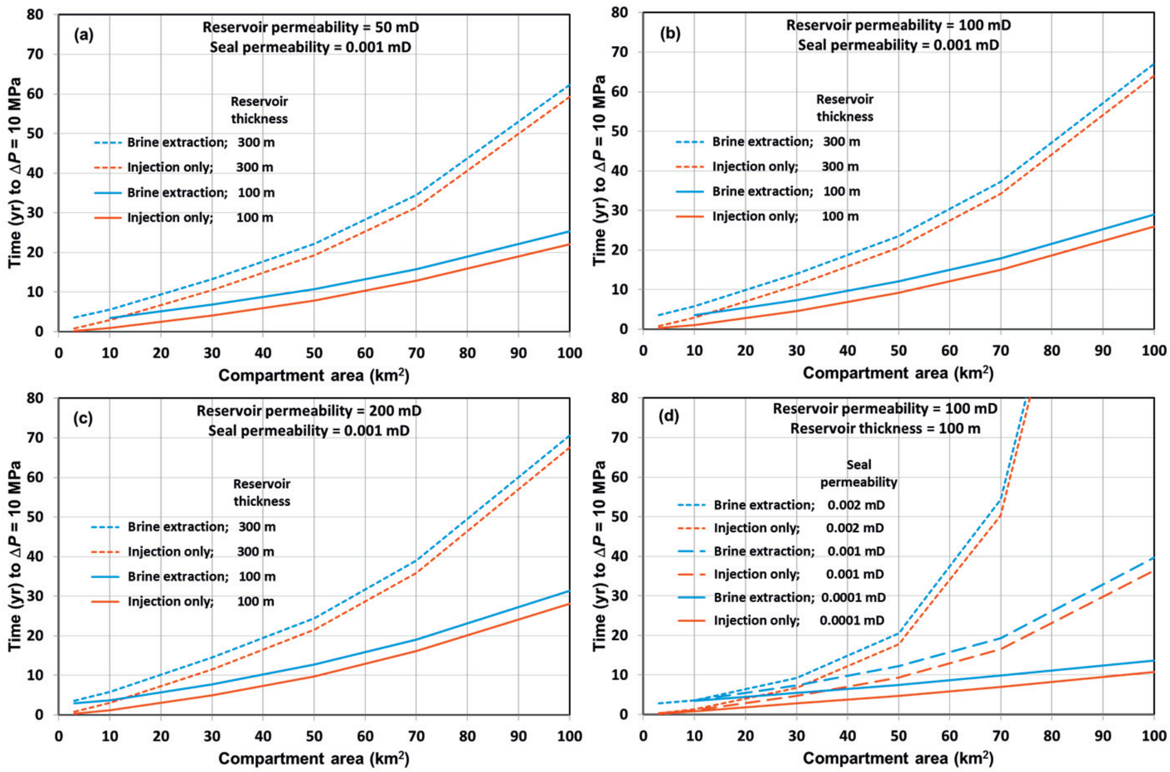


Fig. 3. Time to attain overpressure $\Delta P = 10$ MPa is plotted as a function of reservoir compartment area for a seal permeability of 0.001 mD and a reservoir permeability of (a) 50 mD, (b) 100 mD, and (c) 200 mD. Reservoir thicknesses of 100 and 300 m are included. (d) For a reservoir permeability of 100 mD and thickness of 100 m, ΔP is plotted as a function of reservoir compartment area for a seal permeability of 0.0001, 0.001, and 0.002 mD. Prior to CO_2 injection, brine is extracted at a rate of 1 MT/yr for 4 years. CO_2 is injected at a rate of 1MT/yr, starting at $t = 0$ yr.

3.2. The Use of Pre-Injection Pressure Drawdown to Estimate CO_2 Storage Capacity

As shown in Fig. 2a, underpressure response for pre-injection brine extraction is the mirror image of early-time overpressure response for the injection-only case. This relationship can be illustrated by plotting the correlation of overpressure at t = 3 yr versus the magnitude of underpressure at t = 0 yr, resulting from 4 years of pre-injection brine extraction (Fig. 2c). Note that this correlation includes a very wide range of reservoir area and thickness. The underpressure resulting from brine extraction is a direct measure of overpressure that would have occurred if an equivalent volume of CO_2 were injected without the benefit of brine extraction. The underpressure is also a direct measure of the overpressure that will occur from injecting an equivalent volume of CO_2 with the benefit of brine extraction. The difference between the injection-only and brine-extraction correlations is the measure of pressure relief that occurs 3 years after the start of CO_2 injection. For these correlations, both underpressure and overpressure decrease linearly with increasing reservoir compartment volume; the magnitude of pressure relief also decreases linearly with compartment volume. Hence the benefit of pre-injection brine extraction decreases with increasing compartment volume. Moreover, pre-injection brine extraction functions as an extended pressure drawdown test that informs reservoir managers about how much brine extraction will be required to meet a CO_2 storage target, or whether additional brine extraction is required at all. As was observed in Figs. 3a, 3b, and 3c, reservoir permeability weakly influences these relationships. Note that the regression plotted in Fig. 2c could also be plotted for underpressure at earlier times, so that it may be possible to obtain useful information about the reservoir storage capacity and future brine extraction requirements prior to the end of the brine extraction.

A caveat about this approach concerns the contribution of caprock leakage on overall pressure relief. As shown in Fig. 3d, caprock leakage can make a significant contribution to pressure relief, particularly for large compartment areas (> 30 km^2). If this leakage is diffuse (i.e., without a significant contribution from discrete leakage pathways) and is spread over a large enough area, the environmental consequence may be insignificant, because the vertical flux of brine will be too small to displace brine to shallow freshwater aquifers. However, if the caprock permeability is large enough to cause significant pressure relief for small compartment areas, this may displace enough brine to be of concern. Therefore, it is important that pressure monitoring of pre-injection brine extraction include shallow monitoring wells (Fig. 1a) to assess the contribution of caprock leakage to the overall relief of pressure drawdown.

3.3. Benefits of Dual-Mode Brine-Extraction/CO_2-Injection Wells

A key advantage of our pressure-management approach is that CO_2 is injected at the location of maximum pressure drawdown due to the pre-injection brine extraction. Thus, as shown in Figs. 2a and 3, it will take some time before pore pressures in the vicinity of the dual-mode CO_2-injection well reach initial formation pressure prior to brine extraction. Consequently, pre-injection pressure drawdown buys time and allows reservoir managers to locate the next dual-mode brine-extraction well further away from the CO_2 injector than would be possible if separate single-mode CO_2 injectors and brine producers had been used. This increased well spacing will delay CO_2 breakthrough and extend the operating lifetime of the dual-mode brine-extraction well. Altogether, this approach decreases the total number of wells required for reservoir pressure management and thus decreases capital costs. Because this approach requires less brine extraction to achieve a targeted level of pressure relief than separate single-mode CO_2 injectors and brine producers do, it also reduces operating costs.

3.4. Future Work

In future work we will analyze pressure-management scenarios where dual-mode wells are staged. We will develop pressure-analysis protocols, including using uncertainty quantification tools such as PSUADE [2,3,25]. An important goal of this work will be determining how to best locate shallow monitoring wells, so that pressure measurements are sufficient to assess the contribution of caprock leakage to the overall relief of pressure drawdown during the pre-injection brine-extraction stage. This work will include pressure-management analyses for real field sites.

4. Conclusions

We present a reservoir management approach that can start with a single dual-mode brine-extraction/CO_2-injection well, and possibly one or more deep pressure-monitoring wells. This approach can be expanded into a multi-well field-development strategy, where a number of dual-mode wells are phased in over the life of a field. Dual-mode wells are designed to provide timely, cost-effective information and pressure reduction where it is most needed: at the center of the CO_2 storage zone. Moreover, this approach can identify the target CO_2 storage zone most suitable for CO_2 injection, prior to that injection. This understanding reduces environmental and financial risk. The relationship between pressure drawdown during pre-injection brine extraction and pressure buildup during CO_2 injection directly informs reservoir managers about CO_2 storage capacity for a range of pressure-management options, including no brine extraction. The dual-mode well approach can achieve pressure management with fewer wells and with less brine extraction than an approach that uses separate single-mode wells. This approach generates product water earlier, reduces capital and operating costs, and accelerates the benefits of pressure management. Finally, this approach can be usefully applied beyond geologic CO_2 storage, to other reservoir operations involving the deep injection of fluids.

Acknowledgements

This work was sponsored by the USDOE Fossil Energy, National Energy Technology Laboratory, managed by Traci Rodosta and Andrea McNemar. We want to acknowledge Harris Greenberg of Lawrence Livermore National Laboratory who helped in developing the reservoir engineering correlations used in this study. We also acknowledge Thomas Wolery of Lawrence Livermore National Laboratory for his helpful review of the manuscript. This work was performed under the auspices of the USDOE by Lawrence Livermore National Laboratory under DOE contract DE-AC52-07NA27344.

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