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Energy Procedia 00 (2013) 000–000

Energy Procedia

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GHGT-11

Four-site case study of water extraction from CO_2 storage reservoirs

G. Liu[a], C.D. Gorecki[a*], D. Saini[a], J.M. Bremer[a], R.J. Klapperich[a], and J.R. Braunberger[a]

[a]*Energy & Environmental Research Center, University of North Dakota*
15 North 23rd Street, Stop 9018, Grand Forks, ND 58202-9018

Abstract

Water extraction is one possible means of enhancing storage capacity and managing carbon dioxide (CO_2) storage reservoirs. This study investigates the efficacy of water extraction in CO_2 storage applications through the use of dynamic simulations under various conditions on conceptual heterogeneous geological models based on four CO_2 storage sites in different basins of the world. The simulations indicate that the CO_2 storage capacities can be increased, and pressure and plume management can likely be accomplished through the use of water extraction.

Selection and/or peer-review under responsibility of GHGT

Keywords: water extraction; CO_2 storage; storage capacity; pressure management; reservoir simulation; risk assessment

1. Introduction

Deep saline formations (DSFs) are regarded as the largest potential global resource for the storage of CO_2 underground [1]. Although storage estimates are very high (>1000 Gt of CO_2), there has been concern about injecting into these systems, causing pressure buildup and ultimately limiting capacity. One method to enhance CO_2 storage and manage pressure buildup is extraction of formation waters from CO_2 storage [2].

Most publications have demonstrated the basic concept of the water extraction from a CO_2 storage reservoir based on simulation of the process on idealized homogenous models [2, 3, 4]. However, none of these studies address any heterogeneity or real-world conditions. As a result, the present study investigates scenarios using geologic heterogeneities and sets out to investigate: 1) how much can CO_2

storage capacity be increased by implementing water extraction, 2) how can reservoir pressure be managed using water extraction, 3) can the CO_2 plume be manipulated with water extraction, and 4) how can injection and extraction scenarios be optimized. The full study also addresses potential treatment options and beneficial uses that are not covered in this report [5].

2. Method

Realistic heterogeneous geological models were developed for each study site, populated with data related to porosity, permeability, structure, lithology, formation water quality, temperature, and pressure using Schlumberger's Petrel™ software. The dynamic modeling and simulation started with analysis of boundary condition scenarios to determine the efficiency of storage–extraction models under closed, semiclosed (volumed), or open conditions. The Generalized Equation-of-State Model Compositional Reservoir Simulator (GEM) by the Computer Modelling Group (CMG) was utilized for all simulation scenarios. Moreover, with cost- effective planning, the maximum capacity of CO_2 storage and expected rates of water extraction were optimized by altering CO_2 injection rates and the number and location of wells for both CO_2 injection and water extraction. Site-specific factors such as geologic structure, porosity, permeability, and heterogeneity designed of the four test sites were also considered during optimizations. In addition, CO_2 plume and pressure management strategies were investigated to evaluate the potential to decrease risk associated with CO_2 storage.

3. Case studies and results

3.1. Ketzin case study

The Ketzin pilot site is Europe's longest-operating onshore CO_2 storage site with the aim of increasing the understanding of geological storage of CO_2 in saline aquifers. Ketzin lies on top of the Ketzin–Roskow Anticline, a double-plunging structure trending northeast–southwest, approximately 12 × 43 km in size. The reservoir unit for the site is the Stuttgart Formation, which consists of a series of fluvial channels surrounded by low-reservoir-quality floodplain deposits [6, 11]. Total injection for the project through February 2012 has been about 59,000 tonnes of CO_2 successfully stored in a 630- to 650-m-deep sandstone unit in the anticlinal structure [11]. The Ketzin simulation results presented in this paper are a theoretical case study that do not reflect the operation and regulatory limitations of this site imposed for research and pilot test purposes.

Wells, well logs, an interpreted facies log, and Stuttgart Formation structure maps were incorporated for the injection and monitoring wells according to data presented in Norden et al. [12]. Additionally, fluvial analog data collected for the Stuttgart Formation's fluvial system were integrated into the channel shape and facies modeling process [12]. Most of the properties and parameters for the modeling and simulations, initial reservoir pressure, and well designs were based on publications of the Ketzin project by the GFZ German Research Center and associated research projects [5, 6, 12, 13].

A total of 12 cases shown in Fig. 1 were designed to analyze different scenarios of injection and water extraction. An injection program was selected that maximized injectivity and storage capacity and aimed to inject a target of 2 megatonnes (Mt) per year for a period of 25 years through a single vertical injection well [5]. The results indicate that the boundary conditions have significant effects on the storage capacity and pressure buildup (Cases 1 to 3). The effects between volumed (Case 2) and open conditions

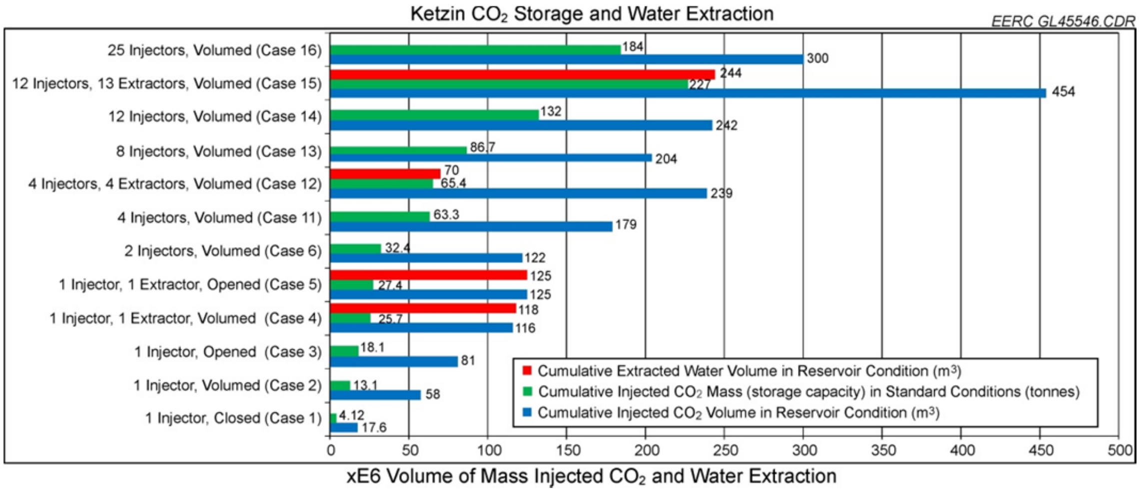

Fig. 1. Comparison of injected CO_2 utilizing multiple combinations of injection and extraction wells: Ketzin case study

(Case 3) show less pressure buildup than the case with closed boundaries (Case 1), especially after adding water extraction in Cases 4 and 5. This is due to the strong influence from the dome structure that restricts the CO_2 movement. For similar reasons, the storage capacity using two CO_2 injectors (Case 6) is better than the capacity using one CO_2 injector and one water extractor in Case 5.

For the multiple-extraction well patterns in Cases 7 through 12, the storage capacity increases with additional extraction wells. The percentage increase achieved by adding extraction wells is far greater than the increase achieved by adding extraction wells and injection wells in like numbers (for example, compare the results for 12 injectors and 13 extractors in Case 11 to the results for 25 injectors in Case 12). It is likely that in these scenarios pressure interference becomes the dominant factor. The use of extraction wells helps reduce the overall pressure and reduces pressure interference between injectors.

3.2. Zama case study

The Zama F pool is one of over 700 hydrocarbon-bearing geologic structures in the Zama Subbasin located in extreme northwestern Alberta, Canada. It has been the site of a combined EOR and storage project operated by Apache Canada, with monitoring support from the EERC through the PCOR Partnership Program. Since 2005, Apache has been injecting acid gas (approximately 70% CO_2 + 30% H_2S) for the simultaneous purpose of enhanced oil recovery (EOR), H_2S disposal, and CO_2 storage. The Keg River pinnacle reefs typically consist of variably dolomitized carbonate and are surrounded and overlain by the very tight anhydrite Muskeg Formation that acts as a cap rock, effectively forming a closed system. A large variation in both porosity and permeability is observed, with a decrease in both properties toward the reef tops. The principal rock types include various carbonate facies with varying degrees of alteration due to secondary leaching and dolomitization [14].

Core calibrated multimineral petrophysics assessments were performed on well logs. Borehole image logs were used to more accurately identify the different facies and determine each facies' properties along the wellbores. Seismic attribute data interpretations were used to identify the reef versus nonreef facies to aid in the distribution of the facies in the reservoir. These properties were then spatially distributed throughout the reservoir using a combination of multiple-point statistics and object modeling workflows to produce equiprobable reef facies, structure, and volumetric realizations.

Seven different cases of simultaneous acid gas injection and formation water extraction were tested, as shown in Fig. 2. In Case 1, acid gas was injected at a base rate (0.113 Mt/year) without the extraction of formation water. In Cases 2, 3, 4, 5, and 6, a water extraction well was placed in the bottom (water) zone of the reef structure. The results of Cases 1 and 2 show that the storage capacity increases from 0.05 to 0.62 Mt with water extraction largely due to the reef acting as a closed system and water extraction helping manage pressure buildup. The storage capacity also increases with decreasing water extraction rate in Cases 3 to 5, because of a delay in gas breakthrough at the extraction well. In Case 6, even when the injection rate was doubled with the highest water extraction rates, storage capacity is still lower than in Cases 3 to 5. Because of the heterogeneous nature of the reservoir and higher injection/extraction rates, early CO_2 breakthrough was observed, limiting the total CO_2 (acid gas) that could be stored in the reef structure in Case 6. With two water extractors in Case 7, results similar to results of Cases 3 through 5 were observed in short injection durations. Overall, a pair of the injection–extraction wells shows the best storage capacity increase and pressure management option for the Zama site [5].

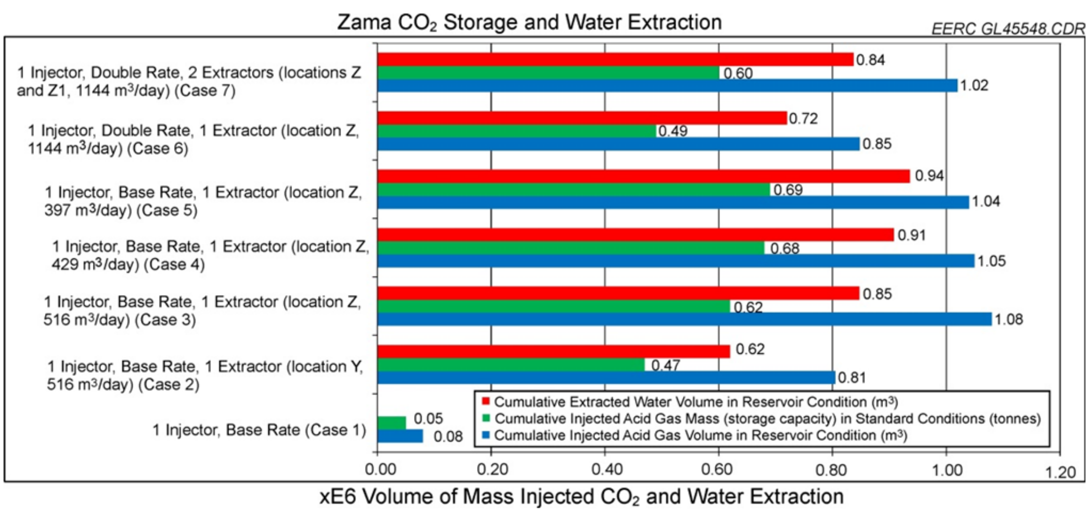

Fig. 2. Comparison of injected CO_2 utilizing multiple combinations of injection and extraction wells: Zama case study

3.3. Gorgon case study

The Gorgon project is a joint venture to inject and store produced CO_2 and is managed by the Chevron, ExxonMobil, and Royal Dutch Shell oil companies, with partners Tokyo Gas, Osaka Gas, and Chubu Electric [15]. The injection target is the Dupuy Formation, a clastic turbidite sequence 2000 m below the surface infrastructure on Barrow Island off the western coast of Australia. The project aims to inject approximately 3.8 Mt/year through eight injection wells, with four water production wells located to the west of the site, which is expected to begin injection in 2014 [15, 16]. Barrow Island is located atop a large (25×38-km), north–south-trending double-plunging anticline.

Well locations and the structure on top of the Upper Massive Sand unit of the Dupuy Formation were used as baseline data according to the results of Flett et al., which suggested a model size for 3.3–3.8 Mt/year injection without reaching the model boundaries [16]. The Upper Massive Sand of Dupuy zones were modeled using Petrel's object modeling processes for fan-type deposits with thicknesses and prevalence input following the publications [16, 17]. The remaining properties and parameters including saturations, relative permeability curves, boundary conditions, initial reservoir pressure, and wells for modeling and simulations were also based on the published data [16, 17] when available, and when not were supplemented by AGD data.

Seven hypothetical cases (Fig. 3) were simulated by using the planned eight injection wells and four extraction wells [5]. The base scenario will inject 0.5 Mt/year (base rate) through each well for an investigational period of 25 and 50 years, for a total of 100 and 200 Mt CO_2 injections. The effects of extraction on capacity were minimal in Cases 1 through 5, as the reservoir has excellent injectivity and capacity, meaning that the upper limit of injection was not achieved through these simulations. This is the reason why the total storage in Cases 1 through 5 is quite linear with regard to injection rate and period. Cases 6 and 7 sought to maximize the injection rate, beginning with 7.5 times the base yearly injection rate, or 3.75 Mt per year per well for 25 years. Because of the higher injection rates, pressure increases near the injection wells were expected to cause issues that may be alleviated by water extraction. Simulations under this scenario resulted in storage capacities of 551 Mt without water extraction, which increased to 637 Mt with water extraction, an increase of 16%. Pressure management through water extraction proved very consistent, with pressures reduced by approximately 20% from Case 1 to Case 2.

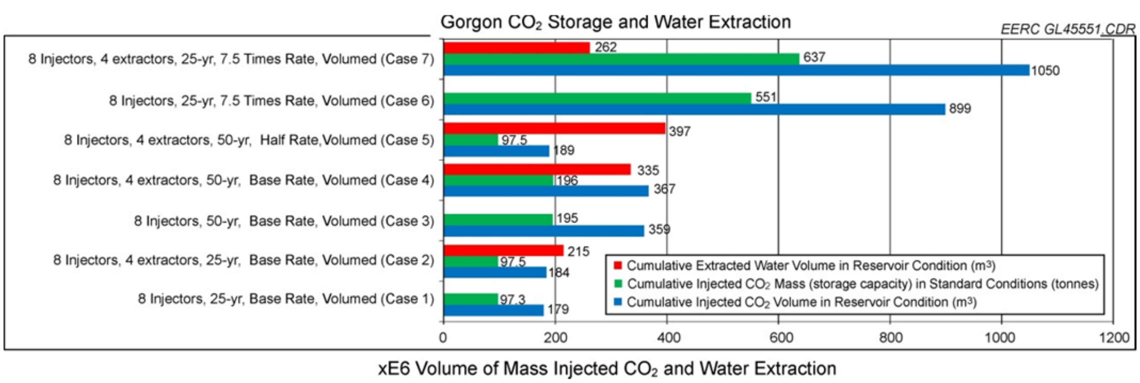

Fig. 3. Comparison of injected CO_2 utilizing multiple combinations of injection and extraction wells: Gorgon case study

3.4. Teapot Dome case study

Teapot Dome near Casper, Wyoming, is a stacked sedimentary sequence on the western flank of the Powder River Basin, present as an elongated anticline that is adjacent to the Salt Creek Anticline, a commercial oil field currently undergoing CO_2 EOR. Over 1300 wells penetrate the structure at Teapot Dome, which has historical production within the Tensleep and Frontier sandstones and reserves in the Muddy sandstone. Produced water from oil field activities at Teapot Dome is of extremely high quality and has many uses in the semiarid Powder River Basin. Simulation efforts were focused on the Dakota and Lakota Formations for this site, although it is recognized that utilizing several formations in the stratigraphic section is optimal for storing large volumes of CO_2 [18].

Teapot Dome modeling was performed using the AGD variogram ranges from interpreted depositional environments with reported or derived rock properties collected through core analysis, including porosity and permeability, since the petrophysical data for the study area are limited. Teapot Dome data including well locations, picked formation tops, and well logs were available in CD format from the Rocky Mountain Oilfield Testing Center (RMOTC) [19]. As with the other sites, most of the properties and parameters for modeling and simulations were based on published data [20]. The injection and production wells used in the models were a combination of existing wells in the field and hypothetical wells based on optimal locations of geological structure and geology for these scenarios.

Injection/extraction analysis of the Dakota/Lakota Formation at Teapot Dome was investigated through a total of five simulations, as shown in Fig. 4 [5]. The base injection target rate used for the site was 1 Mt per year. The baseline simulation (Case 1) without extracted water resulted in a total storage capacity of 5.2 Mt for the site over 25 years, which is significantly lower than the total injection targeted. In Case 3, one water extractor was added; this scenario resulted in a storage capacity of 11.1 Mt, more than doubling the single injection well results. Further, these results indicate that utilizing an injection–extraction well pair is a more efficient situation than utilizing two injection wells alone (Case 2). An alternative method of increasing storage capacity is using horizontal wells in place of vertical wells. In Case 4, two 1-km-long horizontal wells were utilized: one for injection and one for water extraction. This case resulted in 19.1 Mt of storage capacity, nearly doubling the capacity of using a vertical well pair. In addition to the increase in storage capacity, the plume size increased by 44% from Case 3 to Case 4 [5], with an associated drop in overall reservoir pressure. For comparison, Case 5 was run with two 1-km-long horizontal injection wells instead of an injector–extractor pair; this scenario resulted in 17.8 Mt of storage capacity over the 25-year injection period, which was about 7% less storage than the injector–extractor pair. The results from these five cases indicate that storage capacity can be further improved in certain scenarios by utilizing injection–extraction pairs rather than by adding more injectors.

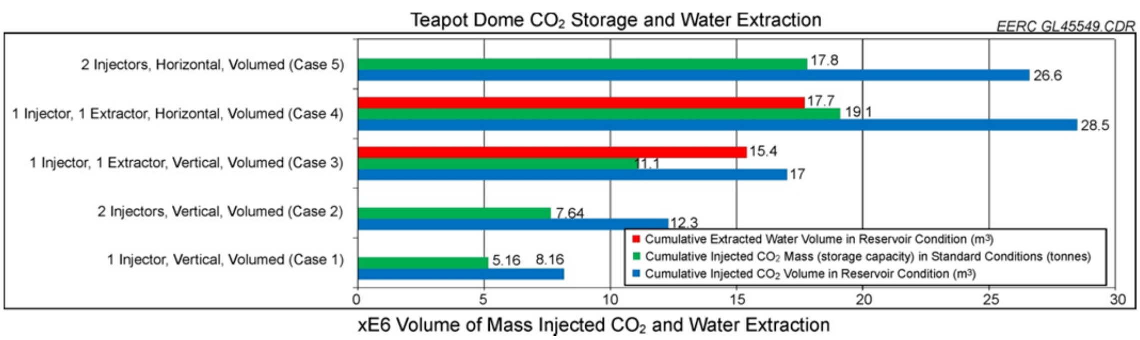

Fig. 4. Comparison of injected CO_2 utilizing multiple combinations of injection and extraction wells: Teapot Dome case study

4. Conclusions

The results of this modeling and simulation effort show that CO_2 storage capacity at all of the test sites can be increased by extracting formation fluids. The range of the CO_2 storage capacity increased from 4% (at the Gorgon site) to 1300% (at the Zama site), depending on a variety of site-specific factors. The ratio of the increased CO_2 storage capacity to water extraction varied from 13:1 to 1:0.4 for CO_2 injection cases with optimizations of injection rates and periods, well designs (vertical or horizontal injection and extraction), well spacings, well locations, and CO_2 breakthroughs.

CO_2 plume and pressure management strategies were found to be dependent on the geologic structure of the site. In the case of the Ketzin site (a dome-shaped structure), water extraction did not appear to have a strong effect on the structure-dominated CO_2 movement. However, in the case of a relatively flat-structured reservoir (the Gorgon and Teapot Dome sites), CO_2 plume and pressure management results were significantly affected by water extraction. At the Gorgon and Teapot Dome sites, CO_2 injection with fluid extraction increased storage capacity by 50% with only a 10% increase in plume size in several scenarios. In other scenarios, fluid extraction resulted in a 10% to 20% pressure reduction with only 5% increase in plume size. Therefore, the CO_2 plume movement trended in the direction of fluid extraction during this process. The influence of water extraction on the migration of pressure and free-phase CO_2 plumes was observed in each of the storage-extraction systems; however, this influence was moderated by other factors, such as geologic structure and local reservoir heterogeneities. The utilization of water extraction for the purposes of reservoir management is best applied to reservoirs where there is low structural control.

Acknowledgements

This material is based upon work supported by the Department of Energy National Energy Technology Laboratory and by the IEA Greenhouse Gas Research Programme under Award Number DE-FC26-05NT42592. Computer Modelling Group Ltd. is gratefully acknowledged for providing software. Thanks also go to Mr. Damion Knudsen for assistance with geological modeling.

Disclaimer

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