PROCEEDINGS, Thirty-Seventh Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, January 30 - February 1, 2012
SGP-TR-194

SIMULATION OF CO_2-EGS IN A FRACTURED RESERVOIR WITH SALT PRECIPITATION

Andrea Borgia, Karsten Pruess, Timothy J. Kneafsey, Curtis M. Oldenburg, and Lehua Pan

Lawrence Berkeley National Laboratory
1 Cyclotron Road
Berkeley, CA 94720, USA
e-mail: aborgia@lbl.gov

ABSTRACT

Using CO_2 as a working fluid in enhanced geothermal systems may allow larger heat extraction for a given pressure gradient. We simulate an idealized initially low-salinity brine-filled reservoir. We inject CO_2 and extract heat from the produced fluid that is at first brine and later CO_2. As the aquifer dries out, salt precipitate in the reservoir inducing, after less than 5 years, clogging of the fractures next to the production well. To reduce this effect, we have also simulated combined brine and CO_2 injection. This strategy more than doubles the life of the well at the expenses of a smaller rate of heat extraction, with a total heat extracted that is 40% larger than in the dry CO_2 case. Simulation of more realistic geologic settings and other fracture plugging models would be necessary to evaluate the feasibility of CO_2-EGS in any particular reservoir.

1. INTRODUCTION

Conventional geothermal energy extraction uses water as the fluid to bring thermal energy to the surface. This methodology has a number of drawbacks for enhanced geothermal systems (EGS) principally related to strong water-rock chemical reactions, but also in terms of environmental impacts through potential overdraft of shallow aquifers with valuable water resources. The concept of using CO_2 in place of water as a heat-transfer fluid has recognized advantages (e.g., Brown, 2000; Fouillac et al., 2004) as follows: (1) a larger rate of heat extraction for the same pressure gradient, (2) less fluid-rock reactivity, and (3) less demand for scarce ground- or surface-water resources.

We simulate an idealized fractured EGS system using CO_2 and CO_2+brine as the working fluid to elucidate fluid flow and heat extraction processes. We focus on the process of geothermal brine displacement by the injected CO_2 with consequent halite precipitation and reservoir clogging. We also model the reinjection of part of the extracted brine with the CO_2 as a mitigation procedure to avoid clogging.

2. SIMULATION WITH ECO2H

We have used the newly developed TOUGH2 module ECO2H (Spycher and Pruess, 2011) which allows the simulation of the H_2O-CO_2-NaCl system at high-temperature (up to 243 °C) and high-pressure (67.6 MPa). We model an idealized EGS system, consisting of a standard five-well-geometry, which is 1-km-thick and 1-km-wide along the diagonal between opposite corner-wells (Fig. 1). Taking advantage of the symmetry of the system, we model only 1/8 of the actual rock volume, but give results for the full rock volume. The grid has 20 × 10-horizontal and 20-vertical grid-blocks with dual porosity (fractures+matrix). Fracture spacing is 10 m and fracture aperture is 10^{-3} m.

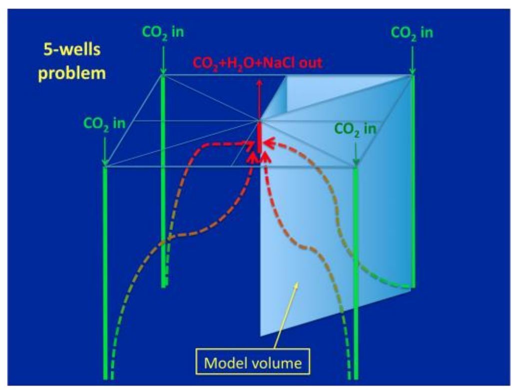

Figure 1: Five-well problem. CO_2 with a variable amount of brine is injected at the corner wells and production of hot fluid is at the central well.

In order to model spatial salt precipitation, the matrix is further subdivided into four concentric shells using the MINC conceptual model (Pruess and Narasimhan, 1985). The model also accounts for two-phase flow and permeability reduction due to salt precipitation based on the model of Verma and Pruess (1988). The model has a normal geothermal gradient of 40 °C/km, starting with 160 °C at 3500 m depth and reaching 200 °C at 4500 m depth. Pressure is hydrostatic from 3500 m downward, calculated for the specific salinity of the EGS reservoir brine. CO_2 is injected at the four corner-wells into the lower 200 m of the reservoir at constant overpressure of 2 MPa above original reservoir pressure with a temperature of 20°C. The center well produces fluid at a constant pressure of 2 MPa below original reservoir pressure. Salinity was varied in the study between a salt mass fraction (X_{sm}) of 0.01 and 0.15 (Fig. 2); here we present the results of the 0.01 mass fraction case.

3. RESULTS

3.1 Injection of dry CO_2

At the beginning of production, brine is extracted, followed by a mixture of brine+CO_2, CO_2 and water vapour, and finally dry CO_2. As soon as the injected CO_2 reaches the production well, usually less than 2 months after injection starts, a drastic drop in heat and fluid production occurs similar to what has been observed previously by Pruess and Spycher (2010) and Wan et al. (2011). This decrease is caused by a lowered flow rate resulting from a reduction in effective permeability due to two-phase flow (liquid + gas) in the proximity of the production well. As the aqueous phase disappears (dries out), the CO_2 flow rate slowly increases over about 1-3 years and the actual heat production reaches a maximum rate that is about 60% larger than the initial rate (Fig. 3). After the maximum rate of heat production occurs at around 5 years after CO_2 injection started, there is a drastic drop in heat produced because of halite precipitation and clogging of the reservoir close to the production well.

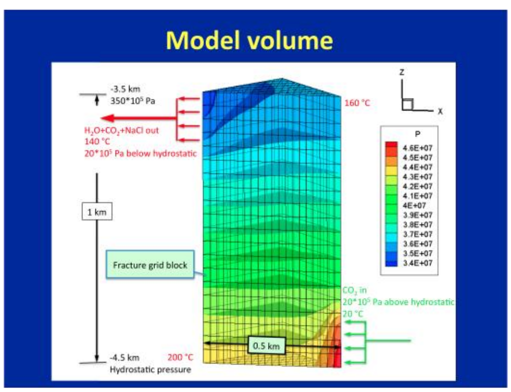

Figure 2: Initial and boundary conditions. See text for explanations.

This phenomena is apparently similar to what has been described by Kleynitz et al. (2001), Lorentz and Muller (2003), Xu et al. (2004), Carpita et al. (2006) and Giorgis et al. (2007) for production and reinjection in gas reservoirs, and injection into geothermal wells. It results from the migration of a highly saline brine front from the injection to the production wells associated with water evaporation into the CO_2 stream. This process induces halite precipitation in the proximity of the production well. This salt precipitation eventually "clogs up" the system at a solid saturation equal to 20% of pore volume based on the Verma and Pruess (1988) model.

The process of increasing salt concentration in the brine is shown in Fig. 4 (a, b, and c). The high salinity envelope propagates in front of the dry-CO_2 plume until it reaches the production well in less than 5 years. Continuing brine migration from the matrix to the fractures and H_2O evaporation into the CO_2 plume eventually leads to salt precipitation and fracture clogging near the production well (Fig. 5a, b, and c).

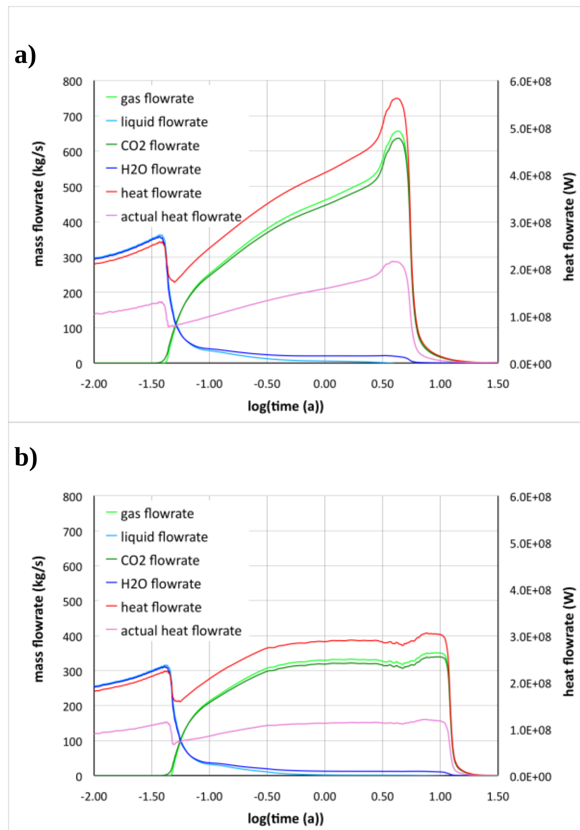

Figure 3: Mass and heat flow rates at the production well. a) dry CO_2 injection simulation; b) brine+CO_2 injection simulation. Actual heat flow rate is the heat produced minus that injected. See text for explanation.

3.2 Injection of CO2+brine

In order to try to avoid reservoir clogging due to salt precipitation, we have tested the case of reinjecting the extracted brine along with CO_2 in a two-phase

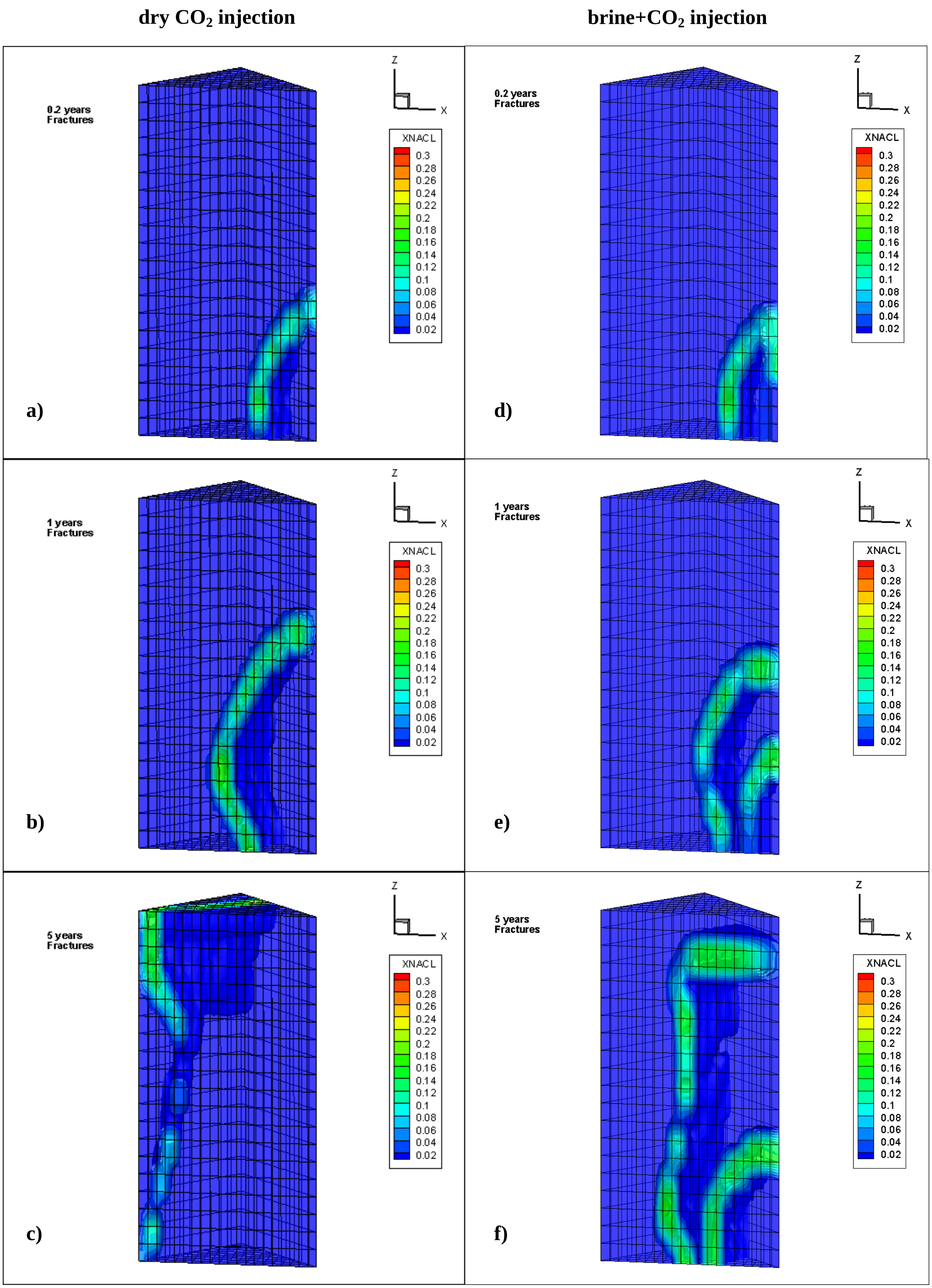

Figure 4: Salt mass fraction (XNACL) in the brine contained in the reservoir's fractures at 0.2 years (a and d), 1 year (b and e), and 5 years (c and f) for the case of dry CO_2 (left) or brine+CO_2 (right) injections. See text for explanation.

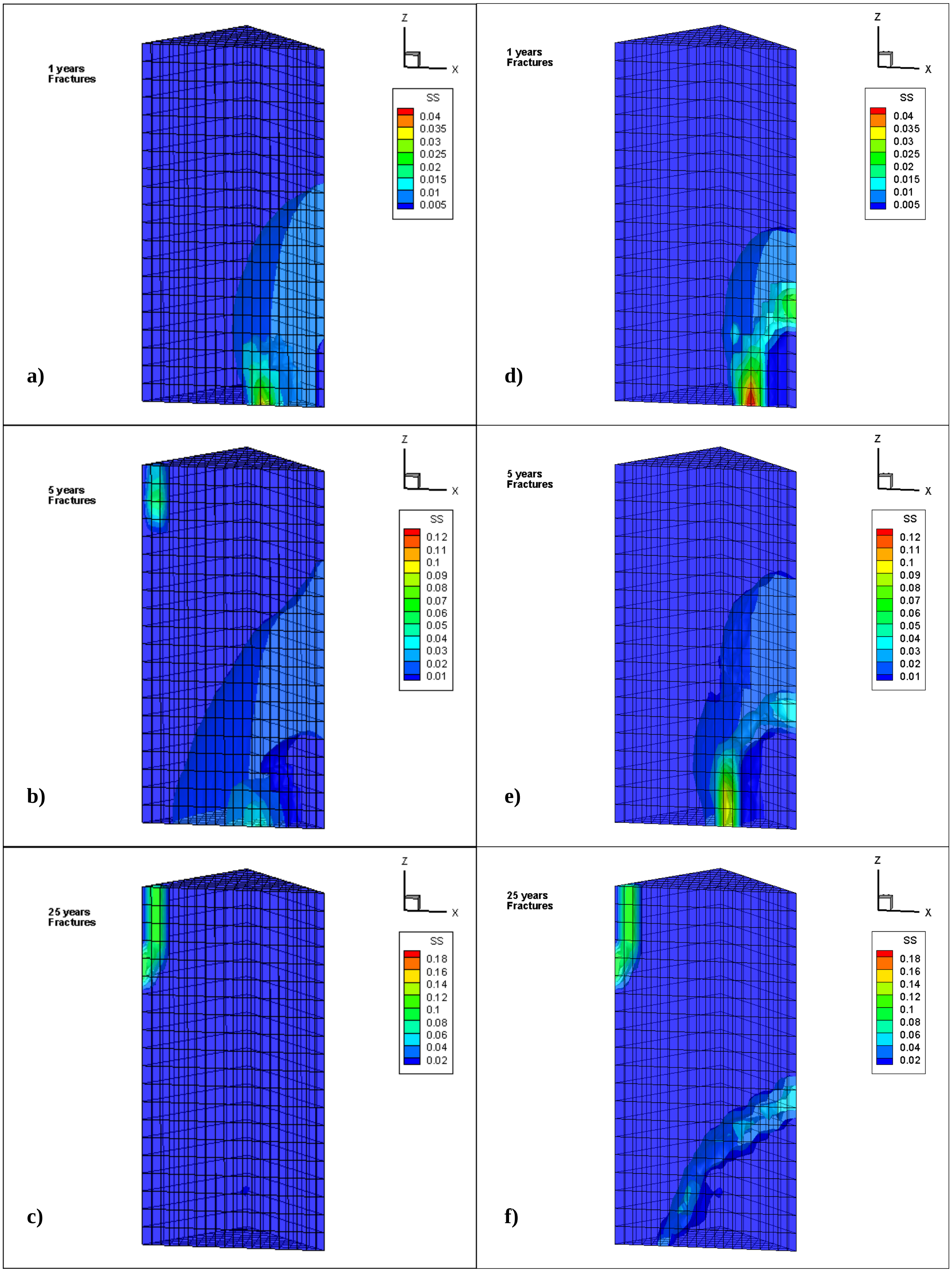

Fig. 5. Halite saturation (SS) in fractures at 1 year (a and d), 5 years (b and e) and 25 years (c and f) for the case of dry CO_2 (left) or brine+CO_2 (right) injection. Scale changes over times. See text for explanation.

mixture with 45% CO_2 and 55% brine by volume. This mixture was selected based on an analysis that showed that larger CO_2 fractions induce salt precipitation with rapid system clogging, and smaller CO_2 fractions maintain two phase flow in the system inhibiting enhanced recovery of heat.

The time evolution of the flow rate at the production well (Fig. 3b) shows the same general pattern found for the dry-CO_2 case (Fig. 3a). There are, however, two major differences:

1) the time at which clogging occurs increases from about 5 to more than 11 years;
2) the maximum heat flow rate decreases by about 45% relative to the maximum heat flow rate of the dry-CO_2 case.

The combination of these two differences results in a total actual heat extracted during the life of the well that is about 40% larger for the brine+CO_2 case than for the dry-CO_2 case.

This result can be understood by comparing salt concentration in the brine for both cases, dry-CO_2 (Fig. 4a, b, and c) versus brine+CO_2 injections (Fig. 4d, e, and f). While in the first case only one high-salinity envelope is generated in front of the CO_2–saturated volume, in the second case two high-salinity envelopes are formed, one in front and one behind the CO_2-rich volume. Like the dry-CO_2 case, the front at the leading edge develops as the water is driven out of the fractures by the propagating CO_2 plume. The trailing front is an evaporation front. In fact, the injected CO_2 increases in temperature as it flows upward through the rock fractures, evolving from saturated to unsaturated in H_2O. Therefore, water evaporates from the brine into the CO_2 plume, concentrating salt in the brine left behind.

Comparing halite saturation in the fractures for the dry-CO_2 case (Fig. 5a, b, and c) with the brine-CO_2 injection case (Fig. 5d, e, and f), one can see how clogging develops in the reservoir. In the second of these two cases, halite precipitation at the production well is delayed for a time period that is much longer than that of the first case. During this period precipitation remains confined to the evaporation front behind the CO_2-plume.

4. CONCLUSIONS

The most important benefit of CO_2 as working fluid is that the actual heat flow rate from a given reservoir can be many times larger than that using the formation brine as the working fluid. This benefit is achieved after the system has gone through the process of substituting the formation brine with CO_2, a process characterized by five periods (c.f. Pruess and Spycher, 2010; Wan et al., 2011):

1) at the beginning, brine is extracted at increasing rates at the production well;
2) after a few weeks, the CO_2 plume reaches the production well creating two-phase-flow and a consequent decrease in total fluid produced;
3) as the fractures dry out the heat flow rate increases again, becoming about 50% larger than that found at the beginning of production;
4) once the CO_2 plume becomes undersaturated with water the water disappears producing an additional peak in heat production;
5) because water evaporates completely into the CO_2 plume, salt precipitates clogging up the fractures even for low salinities close to the production well.

Re-injecting the extracted brine with the CO_2 delays the clogging of the fractures from about 5 to over 11 years, but reduces the heat flow rate significantly. The balance of these two effects, though, is still positive giving a total heat produced that is about 40% larger than that produced by injecting dry CO_2.

Our results show that, in spite of fracture clogging due to salt precipitation, re-injection of formation brine into the reservoir can prolong the life of wells, and delay clogging. Testing of different schemes of water injection may allow resolving the problems associated with salt precipitation while developing CO_2-EGS in fractured saline geothermal aquifers. Testing more realistic geologic reservoirs with more complex flow patterns than the ones investigated here, and with other fracture plugging models will be necessary to evaluate the feasibility of CO_2-EGS in any particular geothermal reservoir.

5. ACKNOWLEDGMENTS

This work was supported by the American Recovery and Reinvestment Act (ARRA), through the Assistant Secretary for Energy Efficiency and Renewable Energy (EERE), Office of Technology Development, Geothermal Technologies Program, of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

6. REFERENCES

Brown, D., 2000. A Hot Dry Rock geothermal energy concept utilizing supercritical CO_2 instead of water. In: Proceedings of the Twenty-Fifth Workshop on Geothermal Reservoir Engineering, Stanford University, CA, USA, p. 233-238.

Carpita, M., Giorgis, T., Battistelli, A., 2006. Modeling CO_2 injection with halite precipitation using an extended Verma & Pruess porosity-permeability model. Proceedings of the TOUGH2 Symposium, Lawrence Berkeley

National Laboratory, Berkeley, CA, USA, May 15-17.

Fouillac, C., Sanjuan, B., Gentier, S., Czernichowski-Lauriol, I., 2004. Could sequestration of CO_2 be combined with the development of Enhanced Geothermal Systems? Paper presented at the Third Annual Conference on Carbon Capture and Sequestration, Alexandria, VA, USA.

Giorgis T., Carpita M., Battistelli A., 2007. Modeling of salt precipitation during the injection of dry CO_2 in a depleated gas reservoir. Energy Conversion and Management, v. 48, p. 1816-1826.

Kleinitz, W., Köheler, M.,Dietzsch, G., 2001. The precipitation of salt in gas producing wells. Paper SPE 68953 presented at the SPE European Formation Damage Conference, La Hague, Netherlands, May 21-22.

Lorentz, S., Muller, W., 2003. Modeling of halite formation in natural gas storage aquifers. Proceedings of the TOUGH2 Symposium, Lawrence Berkeley National Laboratory, Berkeley, CA, USA, May 12-14.

Spycher, N., Pruess, K., 2011. A model for thermophysical properties of CO_2-brine mixtures at elevated temperatures and pressures. Proceedings Thirty-Sixth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, January 31 - February 2, SGP-TR-191.

Pruess, K., Narasimhan, T.N., 1985. A practical method for modeling fluid and heat flow in fractured porous media. Soc. Pet. Eng. J., v. 25, n. 6, p. 14-26.

Pruess, K., Spycher, N., 2010. Enhanced geothermal systems (EGS) with CO_2 as a heat transmission fluid – a scheme for combining recovery of renewable energy with geologic storage of CO_2. Proceedings World Geothermal Congress, Bali, Indonesia, 25-29 April.

Verma, A., Pruess, K., 1988. Thermohydrologic conditions and silica redistribution near high-level nuclear wastes emplaced in saturated geological formations. J. Geophys. Res., v. 93, n. B2, p. 1159-1173.

Wan, Y., Xu T., Pruess K., 2011. Impact of fluid-rock interactions on enhanced geothermal systems with CO_2 as heat transmission fluid. Proceedings Thirty-Sixth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, January 31 - February 2, SGP-TR-191.

Xu, T., Ontoy, Y., Molling, P., Spycher, N., Parini, M., Pruess, K., 2004. Reactive transport modeling of injection well scaling and acidizing at Tiwi field, Philipines. Geothermics, v. 33, p. 477-491.