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A combined saline formation and gas reservoir CO_2 injection pilot in Northern California

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Abstract

A geologic sequestration pilot in the Thornton gas field in Northern California, USA involves injection of up to 4000 tons of CO_2 into a stacked gas and saline formation reservoir. Lawrence Berkeley National Laboratory (LBNL) is leading the pilot test in collaboration with Rosetta Resources, Inc. and Calpine Corporation under the auspices of the U.S. Department of Energy and California Energy Commission's WESTCARB, Regional Carbon Sequestration Partnership. The goals of the pilot include: 1) Demonstrate the feasibility of CO_2 storage in saline formations representative of major geologic sinks in California; 2) Test the feasibility of Enhanced Gas Recovery associated with the early stages of a CO_2 storage project in a depleting gas field; 3) Obtain site-specific information to improve capacity estimation, risk assessment, and performance prediction; 4) Demonstrate and test methods for monitoring CO_2 storage in saline formations and storage/enhanced recovery projects in gas fields; and 5) Gain experience with regulatory permitting and public outreach associated with CO_2 storage in California. Test design is currently underway and field work begins in August 2006.

Keywords: CO_2, geologic sequestration, pilot, field, testing

CO_2 Storage Capacity in California Gas Fields

The Central Valley of California, composed of the Sacramento River basin in the north and San Joaquin River basin in the south, contains numerous saline formations and oil and gas reservoirs that could be used for geologic storage of CO_2. The reservoir rocks in the Central Valley consist of alternating layers of sands and shales deposited in deltaic and marine environments. The saline formations alone are estimated to have a storage capacity of 120 to 500 Gigatonnes (Gt) of CO_2, representing a potential CO_2 sink equal to or greater than 500 years of California's current large point-source CO_2 emissions [1]. In addition to being representative of very large sinks, there are over 11 Megatonnes (Mt)/year of CO_2 emissions within the southern Sacramento River basin near the proposed pilot site.

The proposed field site for the pilot test is in a small-depleted and abandoned gas field located north of Thornton, California in the southern SacramentoValley (Figure 1). Gas production began in the mid 1940s and continued through the late 1980s, producing nearly 1.52 x 10^9 m^3 (53.6 billion cubic feet, Bcf) of natural gas from 14 wells with a heating value of 35.7 to 36.7 MegaJoules/m^3 (960 to 985 Btu/cf) [2]. Natural gas was produced from the top of the upper cretaceous Mokelumne River

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sand formation (referred to locally as the Capital or McCormick sandstone), which forms an East-West trending anticline or dome-like structure, creating the Thornton Gas Field (Figure 2). Gas was also produced from a thin sand lens in the overlying Capay Shale (Figure 3).

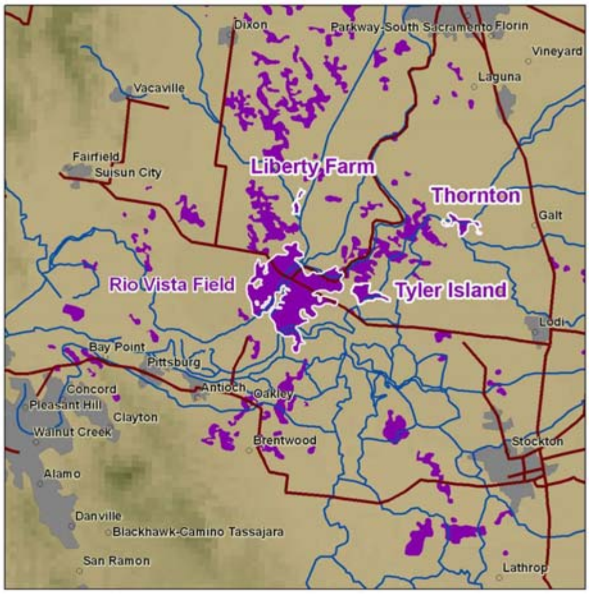

Figure 1. Gas-field locations in the southern Sacramento Valley region.

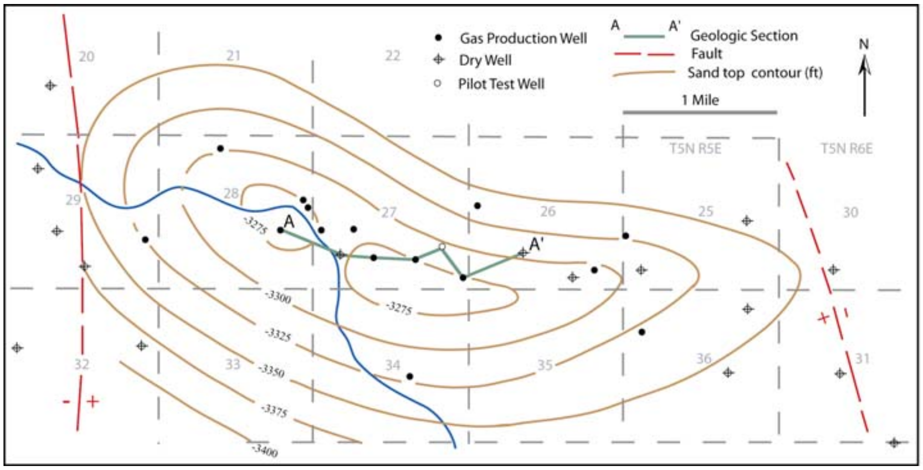

Figure 2. Contours of depth (ft) to top of the gas-producing McCormick Sand unit at the Thornton Gas Field. Proposed pilot test location is shown as an open circle on the section line A-A'.

The Thornton Gas Field is an excellent geologic analog to the much larger Rio Vista Gas Field located a few miles away near Rio Vista, California. The Rio Vista Gas Field is the largest onshore gas field in California and consists of an elongated dome-shaped structure extending over a 12 km (7.5 mi) by 15 km (9.4 mi) area. Since 1936, the Rio Vista Gas Field has produced over 9.3 x 10^{10} m^3 (3.3 Tcf) of natural gas from 365 wells. The formations at Thornton and Rio Vista are representative of dozens of gas-producing fields in California, the cumulative storage capacity of which is estimated at 1.7 Gt. CO_2. Storage capacity of Rio Vista is estimated to be over 300 Mt CO_2, sufficient to accommodate CO_2 emissions for over 80 years from a nearby 650-MW gas-fired power plant.

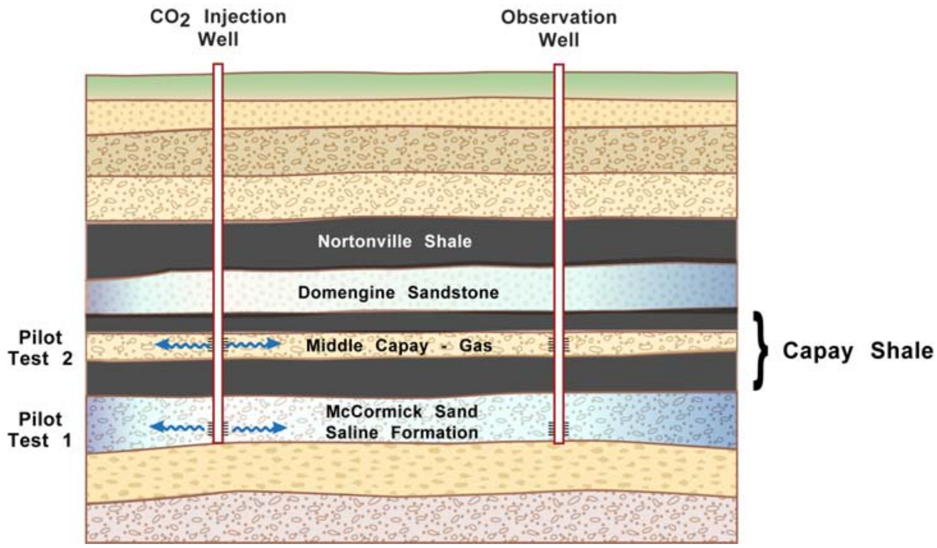

Figure 3. Idealized stratigraphic section (not to scale) showing the injection depths for the stacked reservoir pilot tests to be performed in the middle Capay Shale (depleted gas) and McCormick Sand (saline).

Enhanced Gas Recovery

In addition to evaluating the feasibility of injecting CO_2 into depleted gas reservoirs and large regionally extensive saline aquifers, the pilot test will be the first field-scale test used to demonstrate CO_2 Storage with Enhanced Gas Recovery (CSEGR). Depleted petroleum reservoirs are especially promising targets for CO_2 storage because of the potential to use CO_2 to extract additional oil or natural gas. The benefit of enhanced oil recovery (EOR) using injected CO_2 to swell and mobilize oil from the reservoir toward a production well is well known. CSEGR involves a similar CO_2 injection process, but relies on sweep and methane displacement and has received far less attention ([3], [4], [5]). Depleted natural gas reservoirs are not entirely devoid of methane, therefore, CO_2 injection may enhance methane production by reservoir repressurization or pressure maintenance. Based on the favorable results of numerous CSEGR modeling studies, we sought out and selected the Thornton Gas Field for the dual purpose of demonstrating safe injection of CO_2 into a deep saline aquifer, coupled with a second injection into a depleted gas reservoir to demonstrate safety and to study CSEGR processes. Depleted natural gas reservoirs are attractive targets for sequestration of CO_2 because of their demonstrated ability to trap gas, proven record of gas recovery (i.e., sufficient permeability), existing infrastructure of wells and pipelines, and land use history of gas production and transportation.

Pilot Test Methodology

Two pilot tests involving CO_2 injection will be performed at the Rosetta-Calpine CO_2 Storage project site located in the Thornton Gas Field. The first experiment will involve injecting up to 2000 tons of CO_2 into a brine-filled zone in the McCormick sand, a very fine to medium grained, quartzitic sandstone (Figure 3). Two wells, a CO_2 injector and an observation well, will be installed in a saline zone located beneath the gas trap in the McCormick sand. Our current best estimate for the target depth of the saline test is 1067 to 1098 m (3500 to 3600 ft). Both wells will be drilled to approximately the same depth and the casing will initially be perforated in the saline zone. CO_2 injection will commence after logging and testing the wells.

The second experiment will involve injecting up to 2000 tons of CO_2 into a depletion-drive, depleted gas reservoir located within the Middle Capay shale at a depth of approximately 928 m

(3044 feet). The Capay shale represents a regionally extensive reservoir cap (Figure 3), containing pockets of natural gas in thin interbedded sand lenses. The top of the McCormick sand (Figure 2), a depleted water-drive reservoir at a slightly greater depth of 1003-1021 m, is an alternative location if the Capay sand stringer is absent at the location of the new wells. The casing will be perforated in the gas zone after completing the first experiment and cementing the well perforations shut in the lower saline zone. The second experiment will consist of injecting CO_2 into the depleted gas zone to assess the nature and extent of reservoir pressurization and displacement of methane by CO_2. CO_2 will be purchased from a local supplier and trucked to the pilot site.

A comprehensive set of monitoring techniques will be evaluated and deployed as part of the pilot, aimed at monitoring CO_2 movement in the storage formation as well as detecting any leakage outside the primary storage formation. Candidate geophysical techniques include a combination of surface seismic reflection, Vertical Seismic Profiling (VSP), and cross-well seismic imaging. Use of surface to borehole electromagnetics will be evaluated. A comprehensive suite of wireline logs will augment these geophysical measurements. Injection rates, wellhead and downhole pressures and temperatures will be continuously monitored during injection. Fluid and gas samples will be collected and analyzed during CO_2 injection to evaluate the chemical composition of the fluids. A multilevel fluid sampling system will be utilized to track migration and allow careful evaluation of flow and transport processes that affect success of CSEGR.

Preliminary Modeling Results in Support of Test Design

Preliminary computer simulations were conducted using TOUGH2/EOS7C ([6], [7]) in support of the pilot tests at the conceptual design level. The questions addressed at the conceptual design level include the following:

1. How much CO_2 should be injected and at what rate?
2. What are the expected pressure and temperature changes in the reservoir associated with the injection?
3. What kind of monitoring and sampling should be conducted in the observation well?

Using preliminary estimates of formation properties (permeability 10^{-12} m^2 and porosity 35%), and boundary and initial conditions, preliminary simulations showed that breakthrough of supercritical CO_2 will occur during the saline test within 10 days at an observation well located 39 m from the injector (Figure 4). Approximately 1800 tonnes of CO_2 injected at a rate of 2 kg/s into the uppermost 4 m of the McCormick Sand is required to produce this result. In contrast, breakthrough of CO_2 gas will occur in the 2-3 m thick Capay Shale interval at the same 39 m distance within a couple of days (Figure 5) using far less CO_2 (1000 tonnes injected at a rate of 1.2 kg/s). Pressure changes caused by injection are small in both cases and temperature effects are minimal. A multilevel sampler placed in the observation well (containing a minimum of three pressure and temperature monitoring intervals) is needed in order to observe fluid density effects.

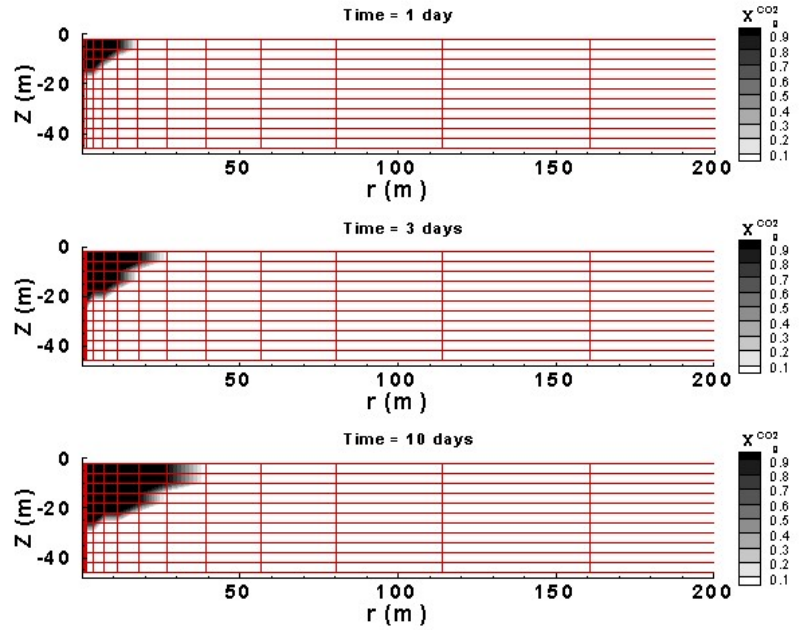

Figure 4. Mass fraction of CO_2 in the gas (X_g^{CO2}) at three times after injection into the upper-most 4 m of the McCormick Sand at a rate of 2 kg/s, assuming radial symmetry.

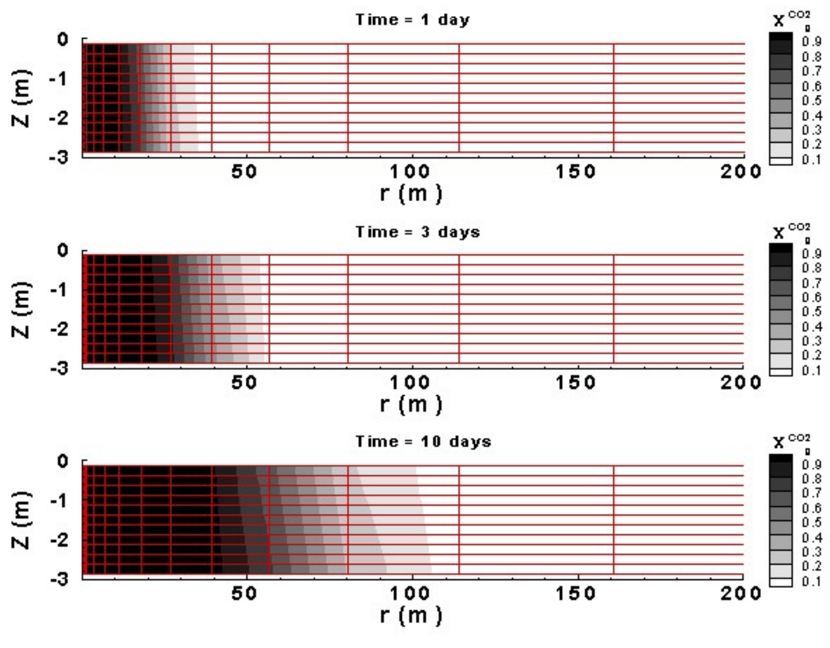

Figure 5. Two-dimensional *r-z* results showing CO_2 mass fraction in the gas phase (X_g^{CO2}) at three times for injection into the gas interval, assuming radial symmetry.

Conclusion

A detailed project management plan and schedule have been developed describing the proposed pilot tests and defining the sequence of test activities. Implementation of the field program will begin in August 2006 starting with site preparation activities including road and well pad construction. Well installation is scheduled for completion by late October 2006, followed by baseline sampling and geophysical surveys. Injection of CO_2 into the saline zone will begin in Spring 2007 and injection into the depleted gas zone is scheduled for Fall 2007. A public outreach program is under development and will be implemented throughout the three-year program.

Acknowledgments

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