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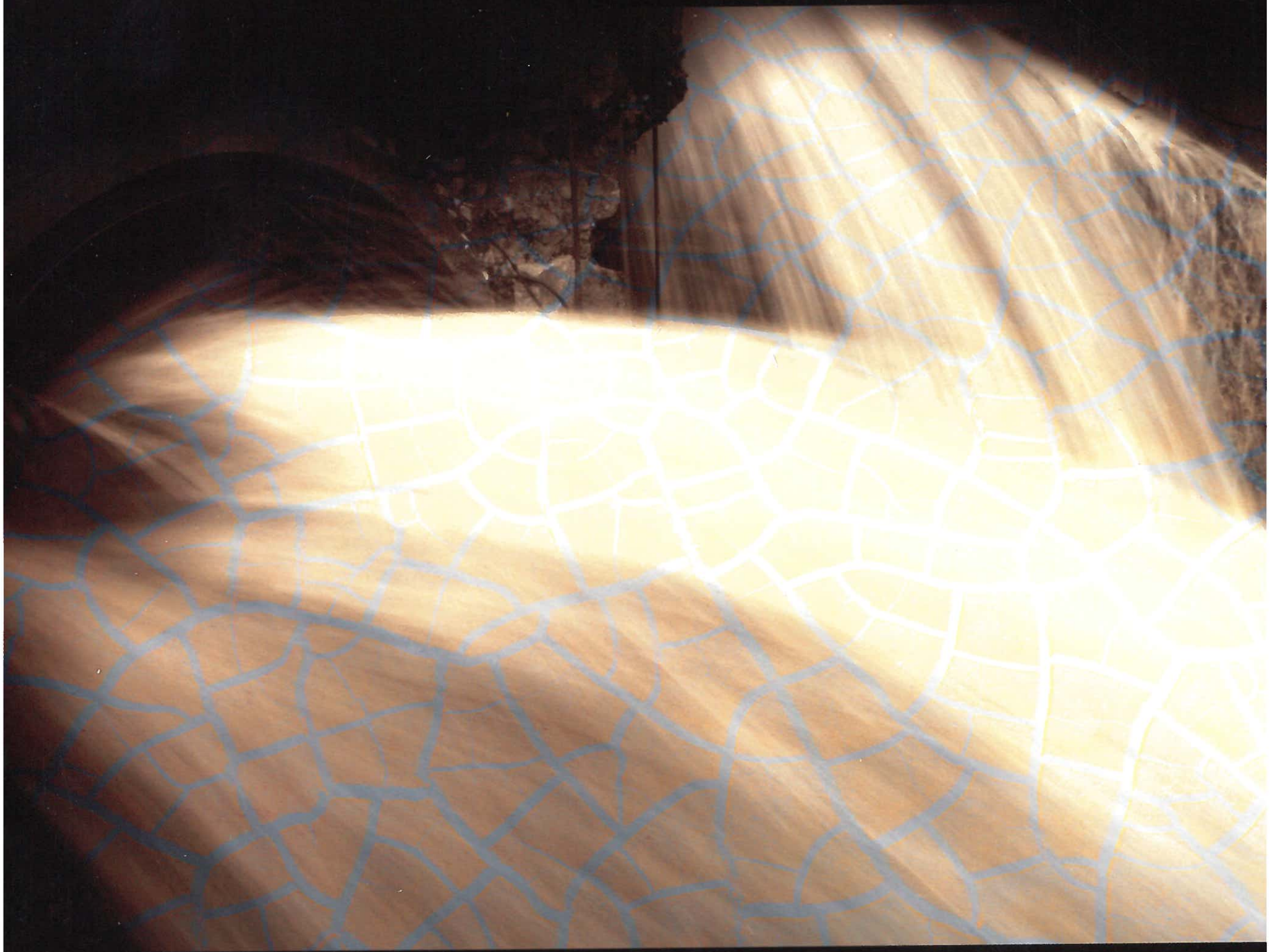

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An integrated strategy for carbon management combining geological CO_2 sequestration, displaced fluid production, and water treatment

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Table of Contents

Figures

Abstract

The preliminary numerical simulations of commercial-scale geological CO_2 sequestration at the Rock Springs Uplift presented in this study strongly suggest that displaced fluids resulting from subsurface CO_2 injection must be managed. To solve this problem, the Wyoming State Geological Survey and Los Alamos National Laboratory propose a strategy that includes integration of fluid production and treatment with injection of CO_2. Using this strategy, 750 million tonnes (Mt) of CO_2 can be injected and contained in a 16 km × 16 km (10 mile × 10 mile) storage domain over a 50-year period. The primary CO_2 sequestration reservoir on the Rock Springs Uplift is the Weber Sandstone, and the secondary sequestration reservoir is the Madison Limestone.

The numerical simulations demonstrate that, over the course of 50 years with an injection rate of 15 Mt of CO_2 per year (750 Mt total), these sequestration reservoirs can accommodate the injected CO_2. However, as pressure in the reservoir returns to background over the 50 years following injection, the sequestered CO_2 will displace 1 cubic kilometer of formation fluid. For successful CO_2 sequestration, this displaced fluid (6 billion barrels over 75 years) must leave the storage domain and find accommodation space elsewhere. To reduce the risk of large-scale hydrofracture, especially at intraformational fluid-flow barriers and faults, reservoir pressure must be managed. In the suggested strategy, pressure management is accomplished by production of the displaced fluids, with subsequent treatment at surface facilities, yielding 10,000 acre-feet of potable water per year.

In the context of this paper, management of displaced fluids means that the pressure effect of these fluids is confined to the CO_2 storage domain (16 km × 16 km). Without management, the pressure evolution caused by CO_2 injection will migrate over an area larger than 50 km × 50 km. The potential for pressure migration over such large distances greatly increases the need for data that can help us predict possible fluid migration along high-permeability vertical pathways. Also, long migration distances substantially increase the potential for interference with adjacent mineral estates.The cost of monitoring unmanaged fluid flow would be extremely high and characterized by significant uncertainty. In addition, the large quantity and low quality of the displaced fluids (> 20,000 ppm TDS) makes management obligatory.

Background

At the direction of Governor Freudenthal and with the support of the Wyoming Legislature, the Wyoming State Geological Survey initiated a thorough inventory and prioritization of all Wyoming stratigraphic units and geologic sites capable of sequestering commercial quantities of CO_2 (5–15 Mt CO_2/year). This two-year study identified the Paleozoic Tensleep/Weber Sandstone (and stratigraphic equivalent units) as the leading clastic reservoir candidate for commercial-scale geological CO_2 sequestration in Wyoming, and the Paleozoic Madison Limestone as the leading carbonate sequestration reservoir candidate in Wyoming (**Figure 1**). These conclusions were based on unit thickness, overlying low-permeability lithofacies, reservoir properties, regional distribution patterns, formation fluid chemistry characteristics, and preliminary fluid-flow modeling. This endeavor also identified the Rock Springs Uplift in southwestern Wyoming as the most promising geological CO_2 sequestration site in Wyoming, and probably in any Rocky Mountain basin (**Figure 2**; Surdam and Jiao, 2007). This ranking for the Rock Springs Uplift is based on the following attributes:

- Presence of a thick saline aquifer sequence (approximately 750 feet of Weber Sandstone plus approximately 250 feet of Madison Limestone) overlain by a thick sequence of sealing lithologies (**Figure 3**);

- A doubly-plunging anticline with more than 10,000 feet of closed structural relief (**Figure 4**);

- Huge structural element (50 × 35 miles, **Figure 5**);

- Thick, overlying low-permeability lithofacies (5,000 feet of Cretaceous shale and more than 1,500 feet of low-permeability Phosphoria-Chugwater rocks);

- The targeted reservoir unit (Weber Sandstone, **Figure 6**) has characteristics required for CO_2 sequestration, including fluid chemistry, porosity, fluid-flow attributes, burial history (i.e., relatively recent basin inversion resulting in sufficient temperature and pressure at present-day depths between 6,000 to 12,000 feet; Surdam and Jiao, 2007).

The Rock Springs Uplift is a nearly unique CO_2 sequestration site because the uplift structure formed during a relatively late basin inversion approximately 43 million years ago; the potential Paleozoic CO_2 sequestration reservoirs (Weber Sandstone and Madison Limestone) at the crest of the structure are 6,000 to 7,000 feet below the surface (Surdam and Jiao, 2007), and the potential CO_2 sequestration storage units and associated sealing lithologies have not been breached anywhere on the structure. Because the nearest surface exposures of the reservoir units are 50 to 100 miles from the crest of the structure (**Figure 7**), meteoric water has not flushed the units (i.e., the units contain relatively unmodified saline formation fluids). The isolation of the fluids and the mechanical integrity of the confining units suggest that there is

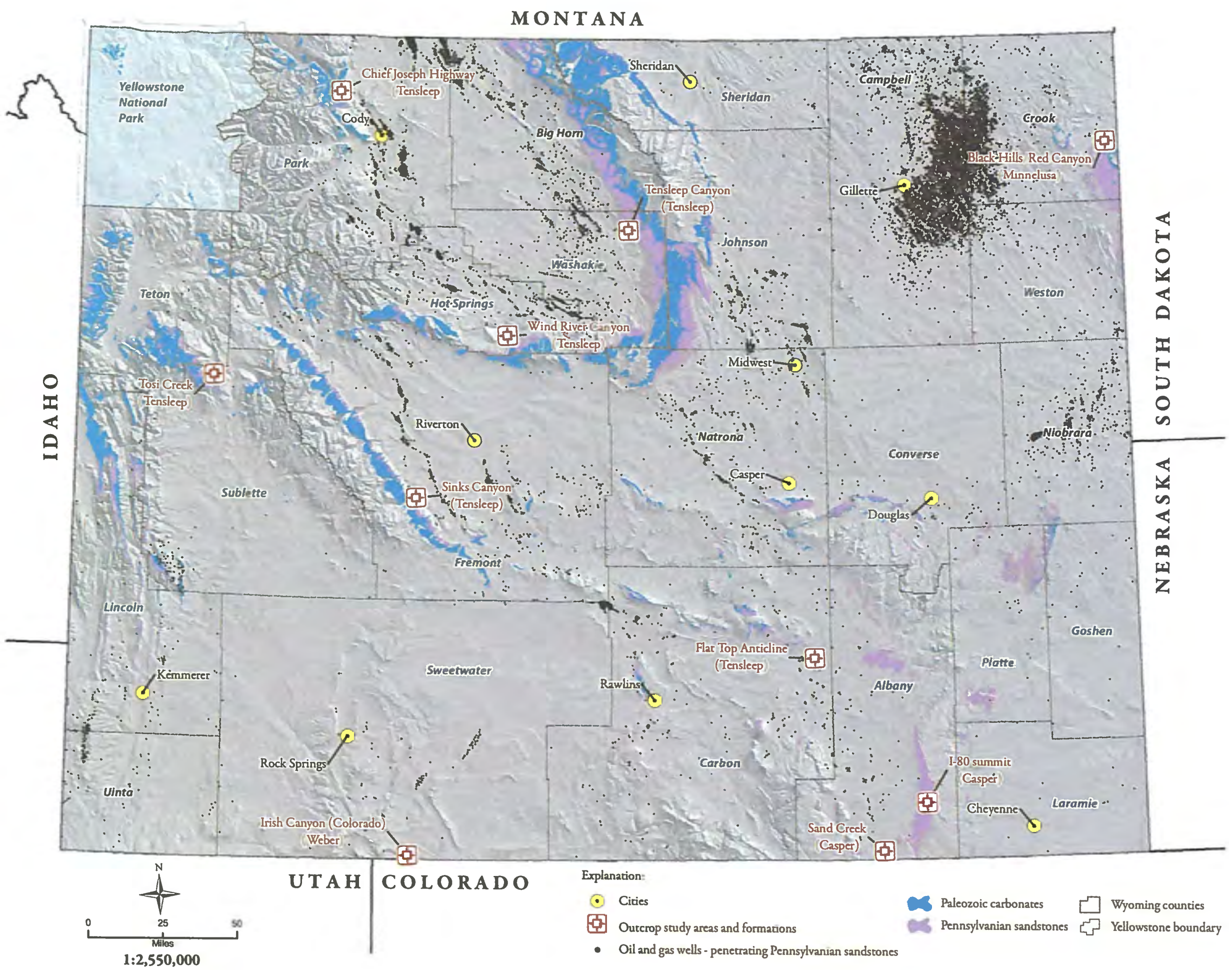


Figure 1. Map showing outcrop distribution of Pennsylvanian Tensleep/Casper/Weber/Madison formations and the Mississippian Madison Limestone equivalents. Oil and gas wells penetrating the Pennsylvanian sandstones are also shown (black dots).

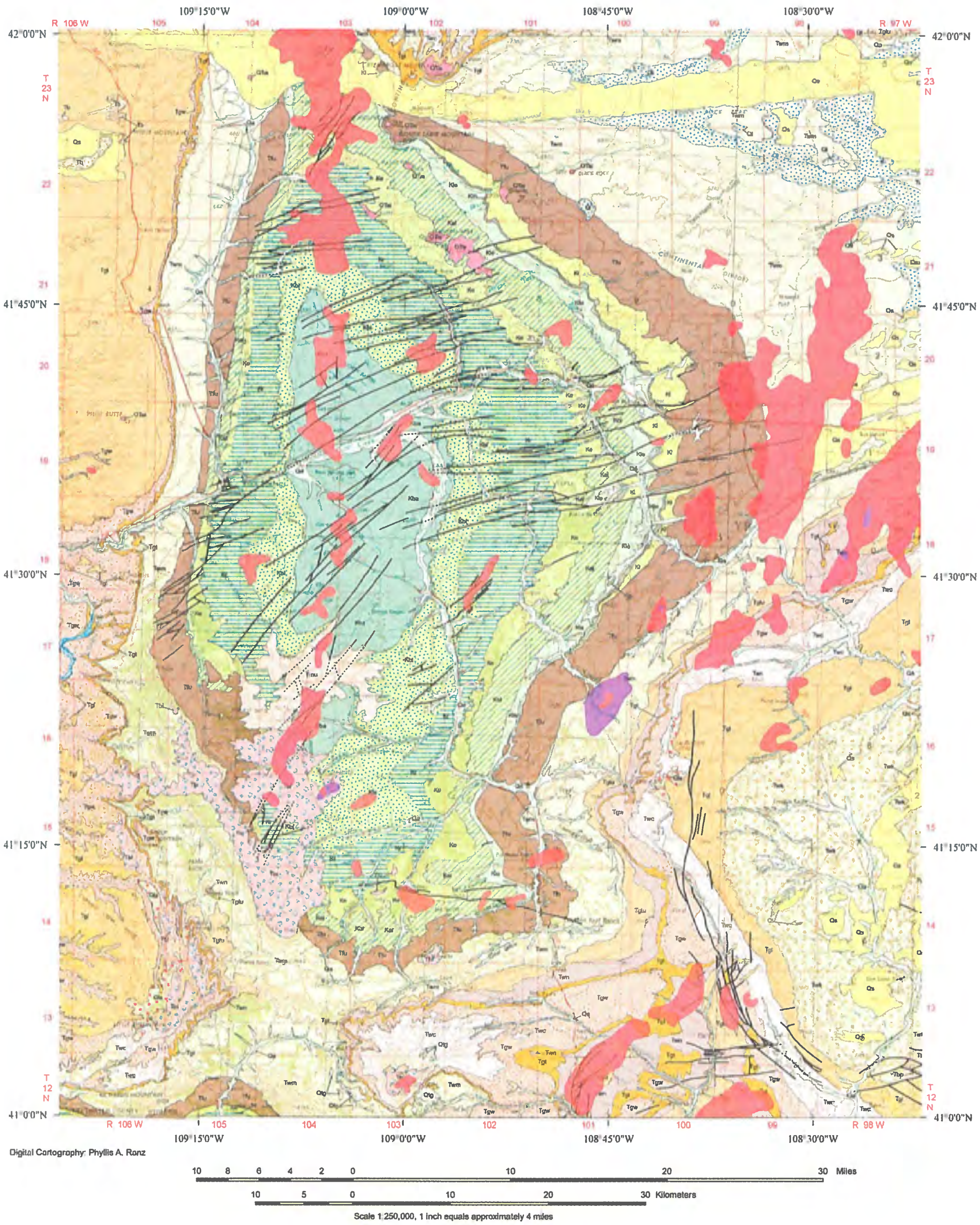


Figure 2. Geologic map of the Rock Springs Uplift, southwestern Wyoming. For a detailed description of the geology, see Surdam and Jiao, 2007.

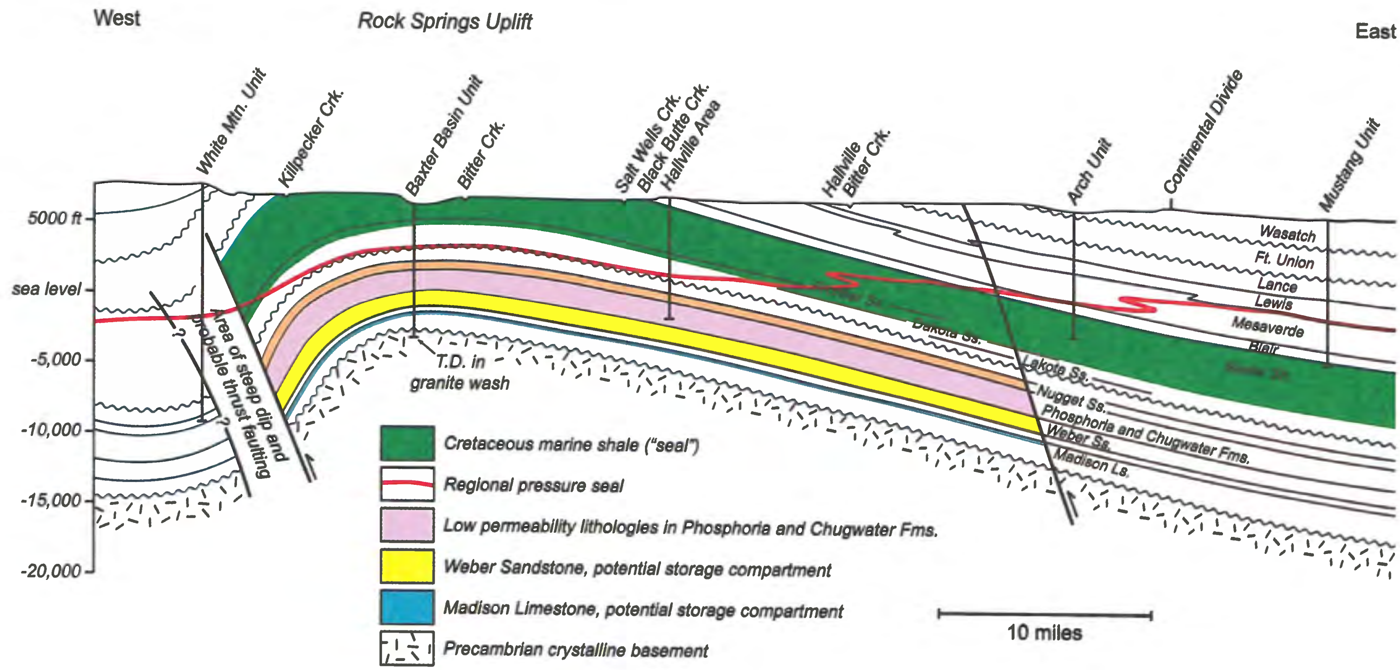


Figure 3. East-west cross section of the Rock Springs Uplift. The primary CO_2 sequestration target formation is the Weber Sandstone and the secondary target is the Madison Limestone. These targeted stratigraphic units are overlain by approximately 5,000 feet of low-permeability Cretaceous shale-rich lithofacies. For more information, see Surdam and Jiao, 2007.

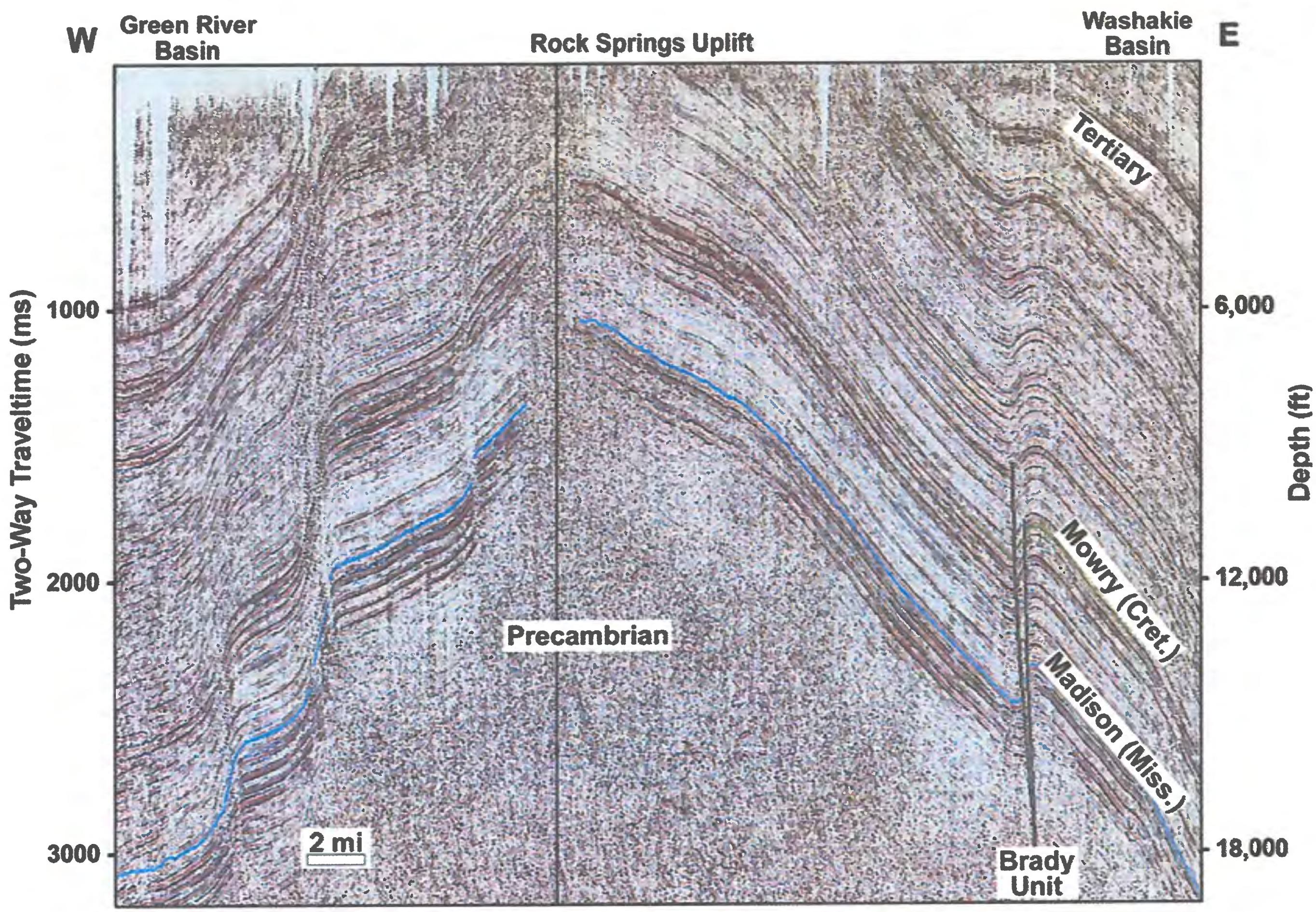


Figure 4. Vertical east-west seismic profile showing that the Rock Springs Uplift is characterized by more than 10,000 feet of structural relief. Modified from Montgomery, 1996.

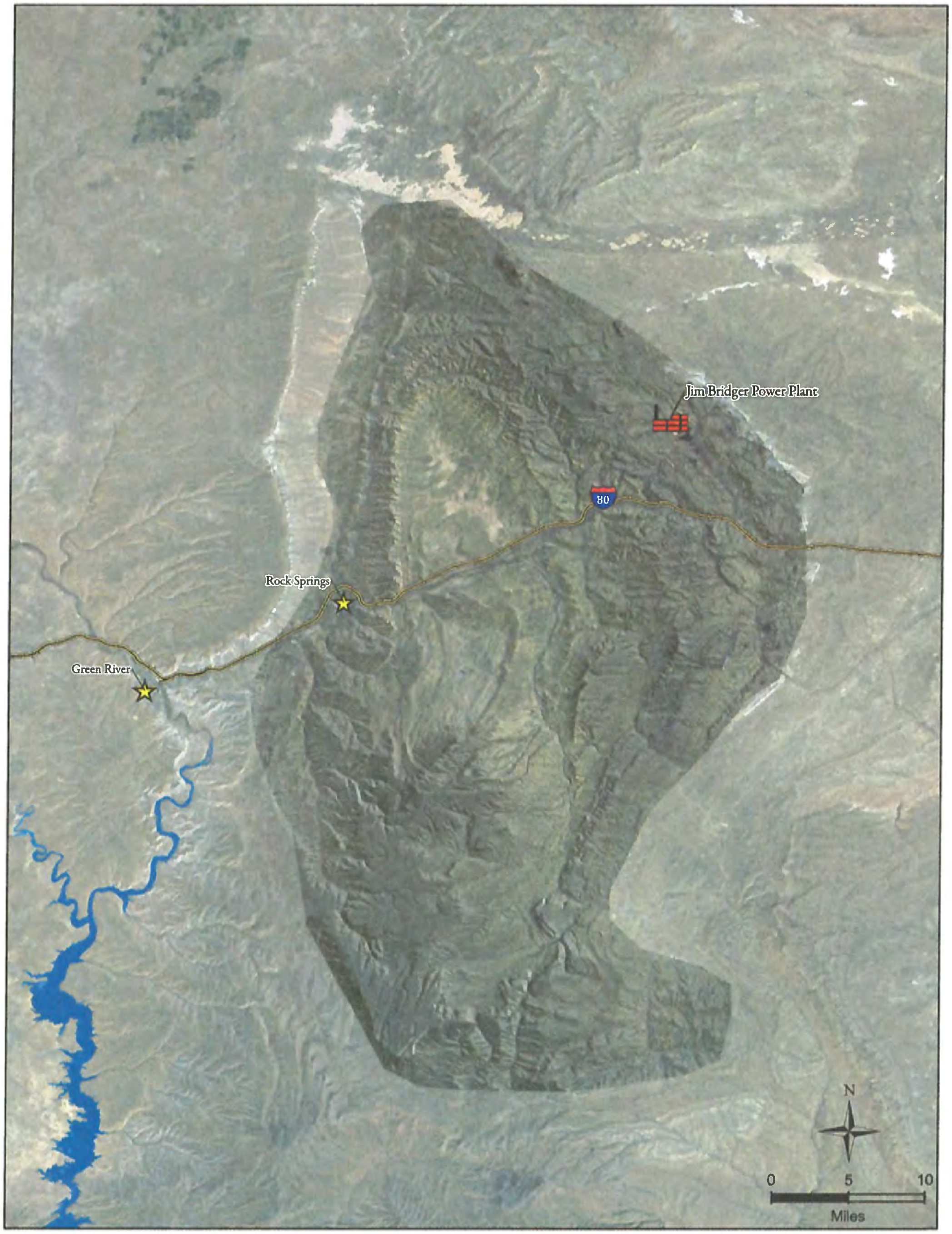


Figure 5. Aerial photo of the Rock Springs Uplift (shaded area). This doubly-plunging (dome) structure covers approximately 1,750 square miles (50 miles × 35 miles).

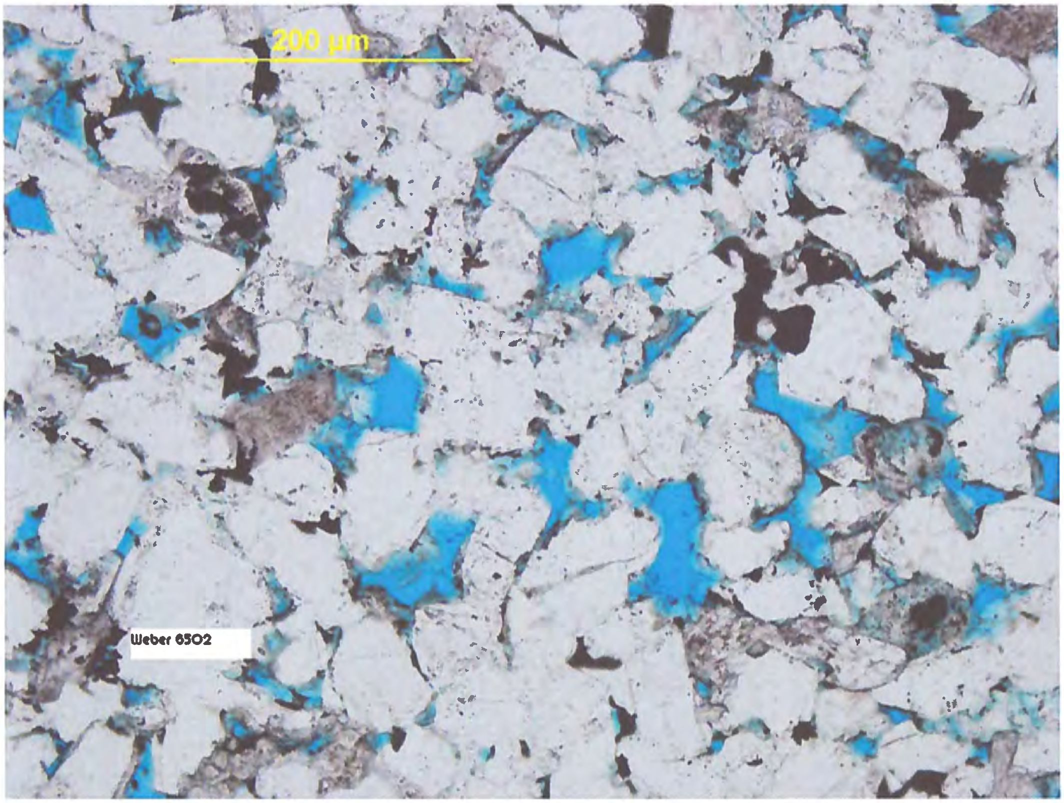


Figure 6. Photomicrograph of Weber Sandstone from crest of Rock Springs Uplift (6,502-foot depth). The pore space in the sandstone is stained blue.

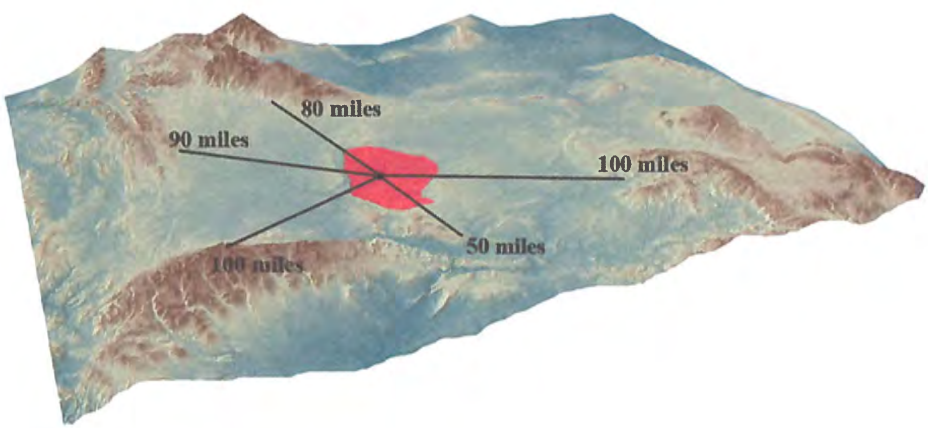


Figure 7. Distances from the Rock Springs Uplift (red area) to the nearest outcrops of Weber Sandstone (see Figure 1).

little probablilty that underground sources of drinking water (USDW) will be endangered by CO_2 sequestration on the Rock Springs Uplift.

The results of the WSGS CO_2 geological sequestration inventory led the agency to collect all readily available geologic, petrophysical, geochemical, and geophysical data on the Rock Springs Uplift, and to build a regional 3-D geologic framework model of the uplift (**Figure 8**). Using the FutureGen protocol and the data described, the WSGS calculated that on the uplift, the Weber Sandstone has sufficient pore space to sequester 18 billion tons (Gt) of CO_2, and the Madison Limestone has sufficient pore space to sequester 8 Gt of CO_2 (Surdam and Jiao, 2007).

To evaluate the potential for a commercial-scale geological CO_2 sequestration project on the Rock Springs Uplift, a numerical simulation was constructed for the sequestration of

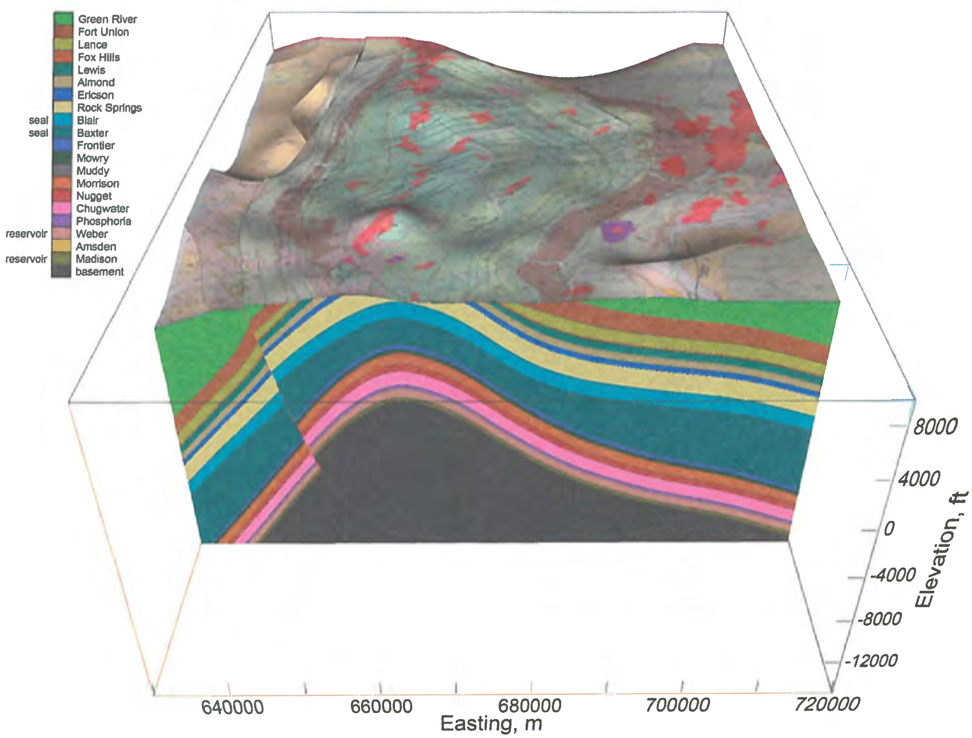


Figure 8. Three-dimensional geologic framework model of the Rock Springs Uplift constructed using formation tops picked from well logs. EarthVision® software was used to create the 3-D geologic model. The targeted CO_2 sequestration reservoirs – the Weber and the Madison formations – are characterized by four-way closure and up to 5,000+ feet of overlying low-permeability Cretaceous shales. The overlay on top of the model is the surface geologic map. See Surdam and Jiao, 2007.

15 Mt of CO_2 per year over a 50-year period. This particular simulation scenario was chosen because it represents approximately 80 percent of the annual CO_2 emissions of the Jim Bridger power plant (with a capacity of 2,200 megawatts (MW)) located on the east flank of the Rock Springs Uplift. Completion and evaluation of this numerical simulation yielded significant insight into CO_2 sequestration problems not normally discussed.

Approach

In cooperation with the Los Alamos National Laboratory (LANL), the WSGS combined its geologic databases with numerical models to improve estimates of the CO_2 sequestration potential of the Rock Springs Uplift (Stauffer et al., 2009). The WSGS 3-D geologic model constructed with EarthVision® software was gridded using LaGrit software (Voronoi mesh). The next step in the simulation process was to populate the gridded 16 km × 16 km × 3.6-km-deep (10 mile × 10 mile × 12,000-foot-deep) rock/fluid cube (**Figures 9, 10,** and **11**; hereafter referred to as the *storage domain*) with logging data from nearby wells (**Figure 5**) and petrophysical data (**Figure 12**) for each of the potentially affected rock/fluid stratigraphic units. Simulations were then performed on the numerical mesh, examining how injection of 15 Mt of CO_2 per year could affect the subsurface at the Rock Springs Uplift. Additionally, shallow and deep sequestration sites on the uplift were compared using the LANL CO_2-PENS software (Stauffer et al., 2009).

The results of these numerical simulations are significant in the global effort to accomplish substantial commercial-scale CO_2 sequestration. Consider the evaluated scenario, where 15 Mt of CO_2 per year for 50 years is sequestered in a nine-point injector pattern within the storage domain on the Rock Springs Uplift (**Figure 13**). The modeled nine-point injector pattern was located near the power plant on the east flank of the uplift. The nine injection wells, each of which would inject 1.7 Mt of CO_2 per year, were spaced approximately one mile apart. For the commercial-scale sequestration scenario, no fluid flow was allowed at the down-dip boundary, and the up-dip boundary pressure was fixed at the initial hydrostatic pressure. After 50 years of injection, the CO_2 plumes around the injection wells just barely impinged on one another (**Figure 13**), and all of the injected CO_2 (750 Mt) was contained within the storage domain (**Figure 14**). During the 50-year injection period, the maximum pressure did not exceed the minimum principal stress from near the start of injection until after injection stopped, with a peak pressure near the injectors of more than 84 MPa. The modeling in this scenario demonstrates that once injection stops, the pressure buildup in the individual injection wells decreases to near initial pressure in 25 years (**Figure 15**).

The problem

The most critical problem in this geological CO_2 sequestration simulation is the volume of injected CO_2 and the displaced fluid leaving the storage domain (**Figure 16**). Each of the nine injector wells must displace 52 Mt of fluid over a 50-year period (**Figure 17**). Not only

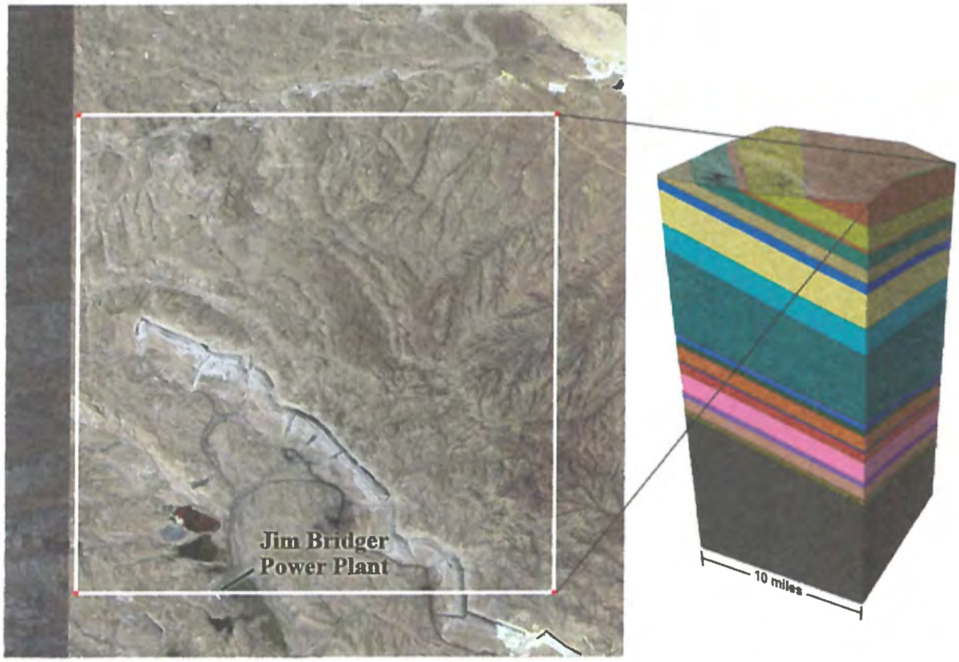


Figure 9. Aerial photo showing the proposed CO_2 demonstration area (16 × 16 km, or 10 × 10 miles), plus the geology block extracted from the 3-D model for this area.

must the fluid be displaced, it must leave the storage domain in order for the rock/fluid environment to remain below the frac pressure gradient (**Figure 17**). The displaced fluids must find accommodation space outside the storage domain in order for the injected CO_2 to be contained there. In the example cited above, 750 Mt of CO_2 is sequestered in the storage domain and 1 cubic kilometer of fluid must leave the domain over a 75-year period (50 years of CO_2 injection and 25 years post-injection, **Figure 16**). The key questions are as follows: Can the accommodation space be found within the geologic site to accept this huge volume of fluid that must leave the storage domain? If so, given the heterogeneity of most geological settings (fluid-flow compartmentalization), can fluid migration pathways be maintained so the displaced fluid can migrate from the storage domain to some external accommodation space without disrupting the confining units and destroying the integrity of the rock/fluid system?

To illustrate the immensity of accommodating 1 cubic kilometer of displaced fluid over a 75-year period, consider the following. One cubic kilometer of fluid is equal to 6 billion barrels, or 810,000 acre-feet, of fluid. In 120 years of production, the Salt Creek oil field (the largest oil field in Wyoming) has produced 680 million barrels of oil (i.e., one-tenth of one cubic

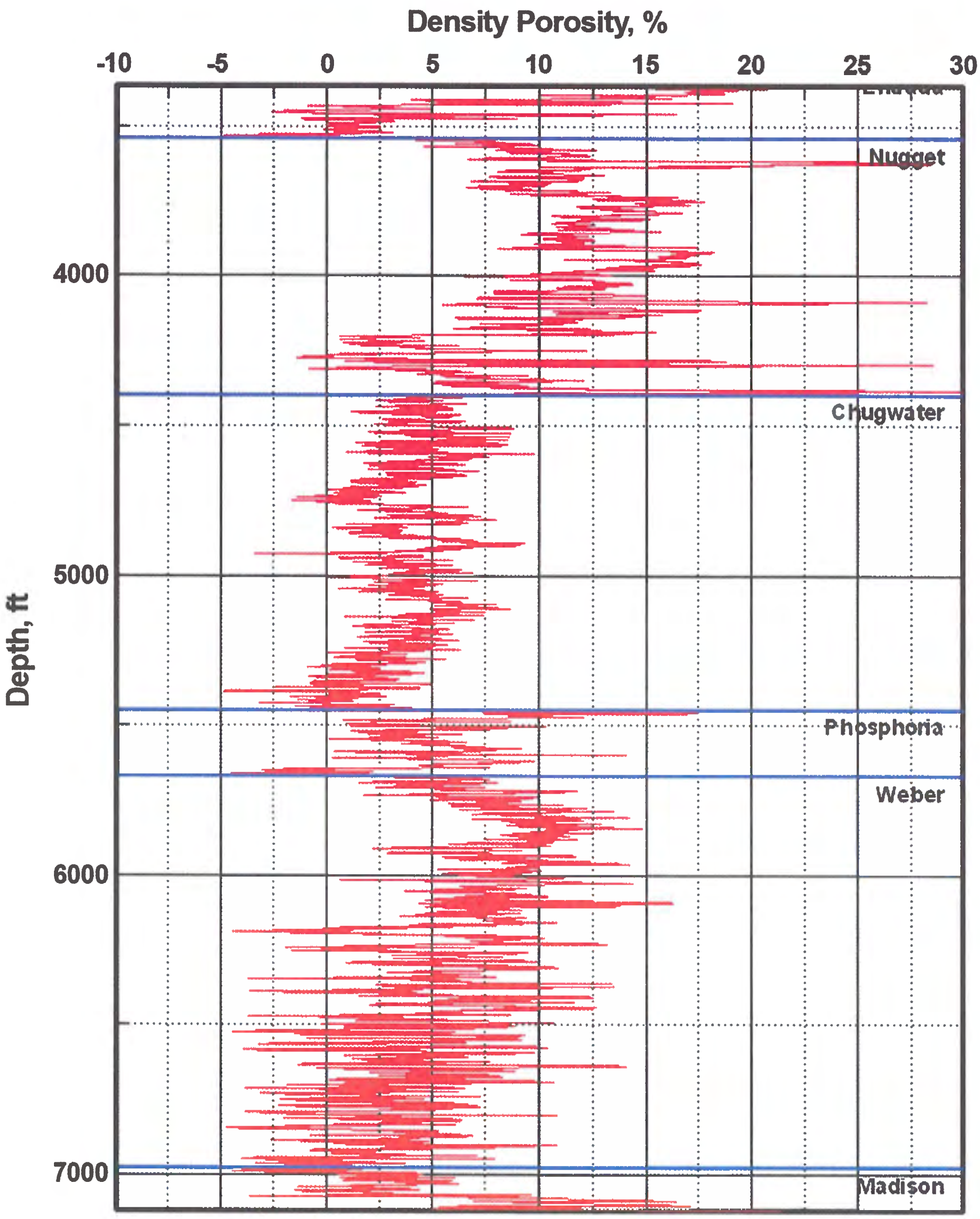


Figure 10. Typical density-porosity vs. depth log for the Paleozoic and lower Mesozoic section at the Rock Springs Uplift.

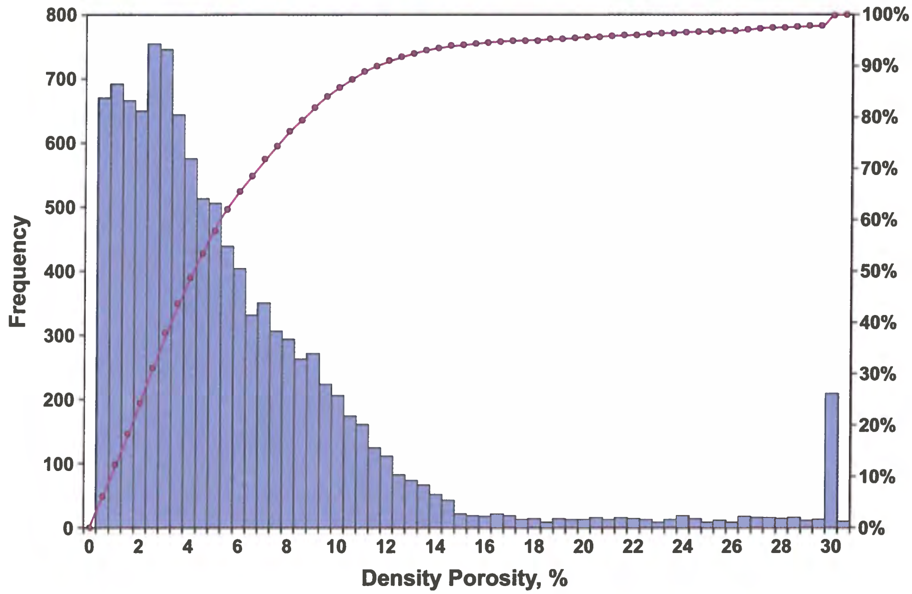


Figure 11. Density-porosity histogram of the Weber Sandstone from 15 well logs, Rock Springs Uplift.

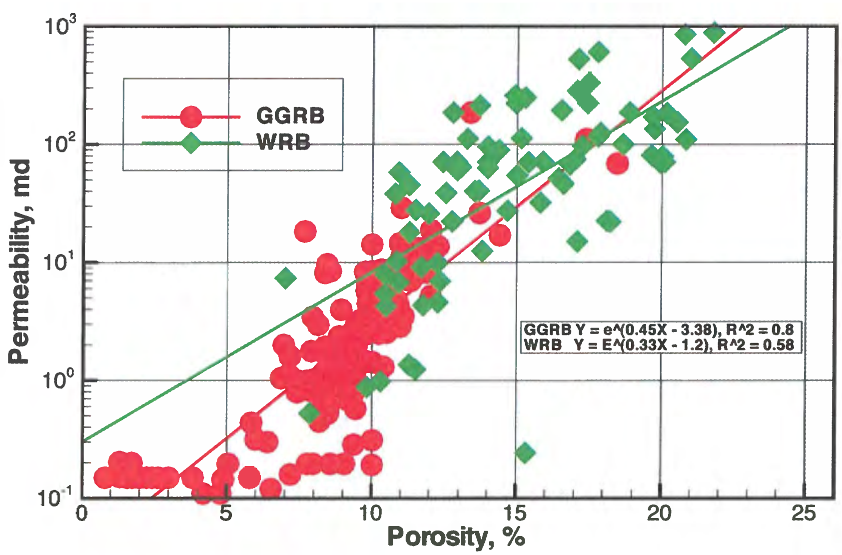


Figure 12. Plot of permeability vs. porosity from core analyses of the Weber/Tensleep Sandstone in the Wind River and Greater Green River basins. Data from Fox et al., 1975.

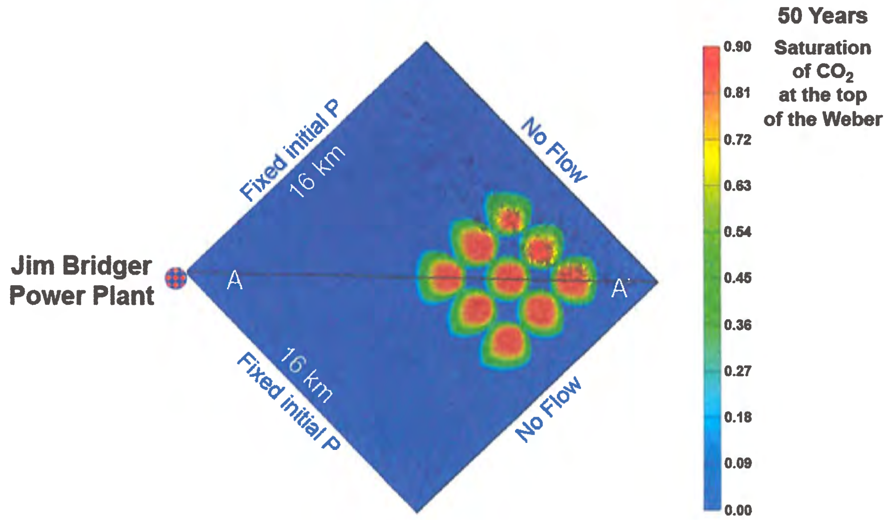


Figure 13. Map view of the nine-point injection project that was numerically simulated for the sequestration of 750 Mt CO_2 over a 50-year period. Boundary conditions for the simulation are shown on the diagram. The vertical scale bar shows CO_2 saturation.

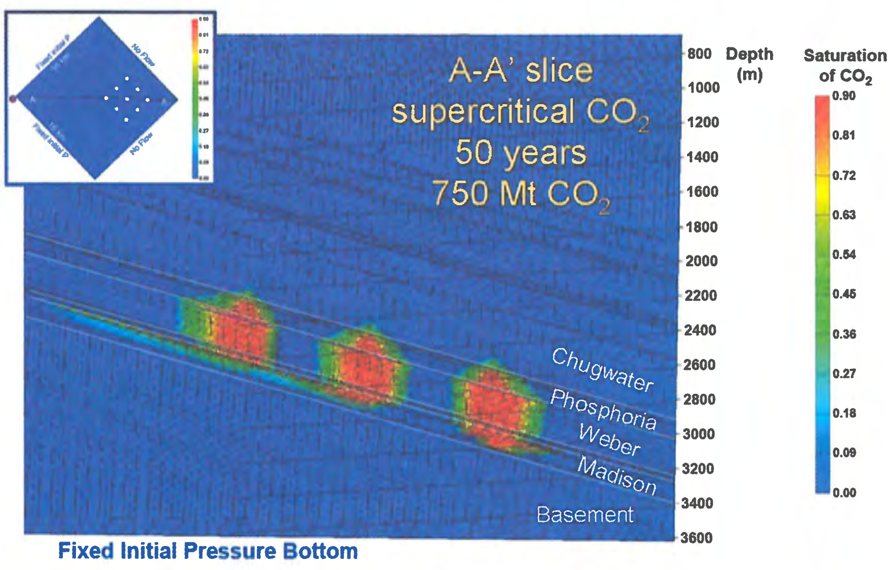
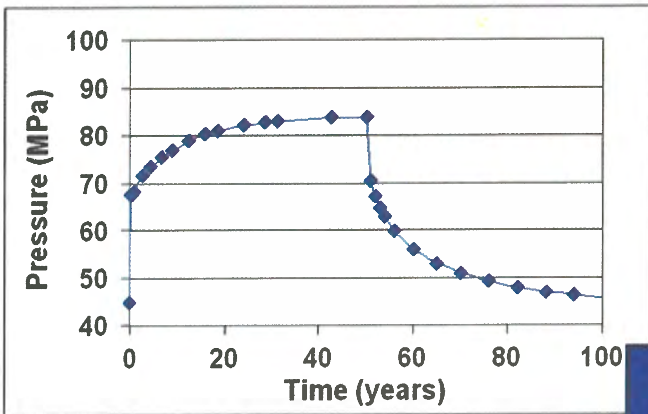


Figure 14. Cross section through three injection wells showing the dispersal of injected CO_2 after 50 years of injection at a rate of 1.67 Mt CO_2/year in each injection well. Note that all of the injected CO_2 is confined within the storage domain. Modified from Stauffer et al., 2009.



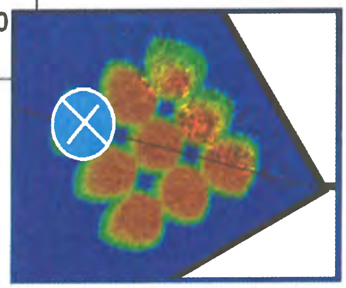


Figure 15. Pressure evolution of one of the CO_2 injection wells. The initial pressure is 45 MPa; after 50 years of CO_2 injection, the pressure for a single injector well is 84 MPa. Twenty-five years after cessation of CO_2 injection, well pressure decreases to near initial presure (45 MPa).

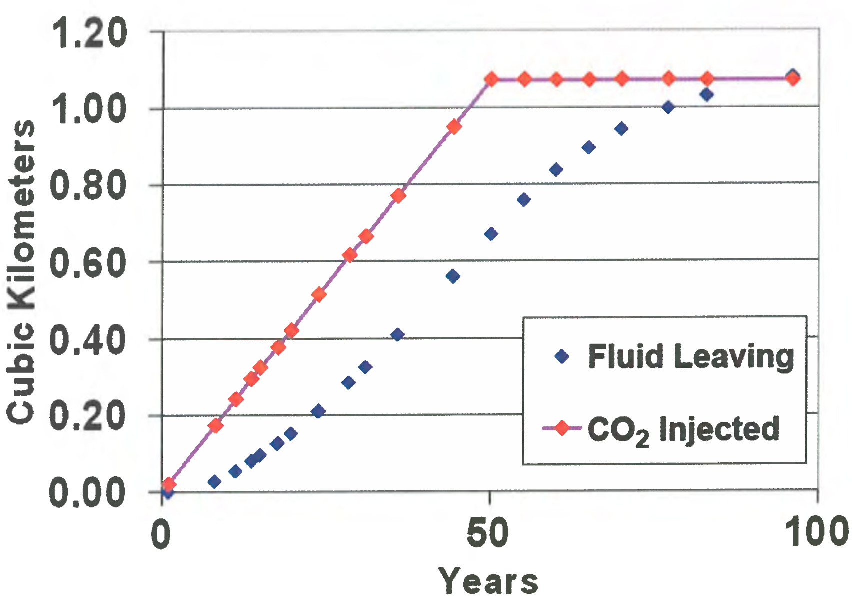


Figure 16. Relationship between total CO_2 injected in the 9-point injection simulation (750 Mt CO_2 over 50 years) and the amount of fluid that must leave the storage domain to maintain boundary conditions in the numerical simulation (remain below frac pressures).

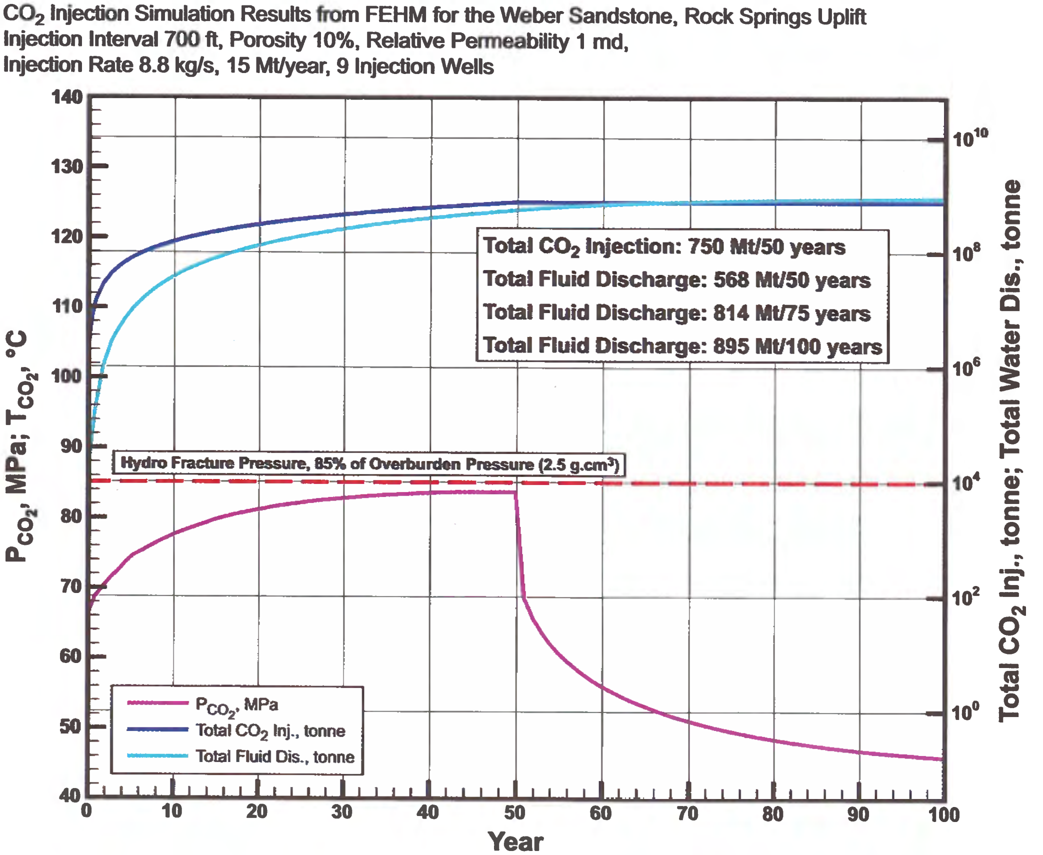


Figure 17. Pressure evolution, total CO_2 injected, and fluid displaced for nine injection wells over a 50-year period. The numerical simulation that produced this diagram is Los Alamos National Laboratory's FEHM software.

kilometer of fluid). Sequestering the CO_2 emitted by the Jim Bridger power plant will require displacement of a volume of fluid nearly ten times that of Salt Creek field production.

To further illustrate the magnitude of the displaced fluid plume associated with the sequestration scenario summarized in **Figure 16**, we used FEHM software to model the initial and 50-year pressure configurations. The results of this modeling (**Figure 18**) allow an evaluation of the dimensions of the displaced fluid plume after 50 years of CO_2 injection (750 Mt CO_2). By monitoring the pressure effect (ΔP) in the simulations, it is possible to track the migration of the displaced fluid plume. **Figure 18** shows that after 50 years of injection, the displaced fluid plume either significantly affects the rock/fluid system 50 km (31 miles) beyond the CO_2 storage domain (red square in **Figure 18**), or migrates 50 km (31 miles) updip from the injection site.

These preliminary numerical simulations of commercial-scale geological CO_2 sequestration on the Rock Springs Uplift strongly suggest that displaced fluids resulting from subsurface CO_2 injection must be managed. Displaced fluid migration over large distances greatly increases the possibility that the migrating fluid will encounter flow barriers or high-permeability fluid-flow pathways that will cause significant diversions from the modeled fluid-flow behavior. Also, migration over large distances substantially increases the potential for interference with adjacent mineral estates.

The solution: an integrated strategy

It is clear that fluids displaced by subsurface CO_2 injection must be managed. To solve this problem, the WSGS proposes a strategy that includes integration of fluid production and treatment with injection of CO_2. Using this strategy, 750 Mt of CO_2 can be injected and sequestered in the storage domain over a 50-year period, and the 1 cubic kilometer of fluid produced from the structure can be treated at the surface.

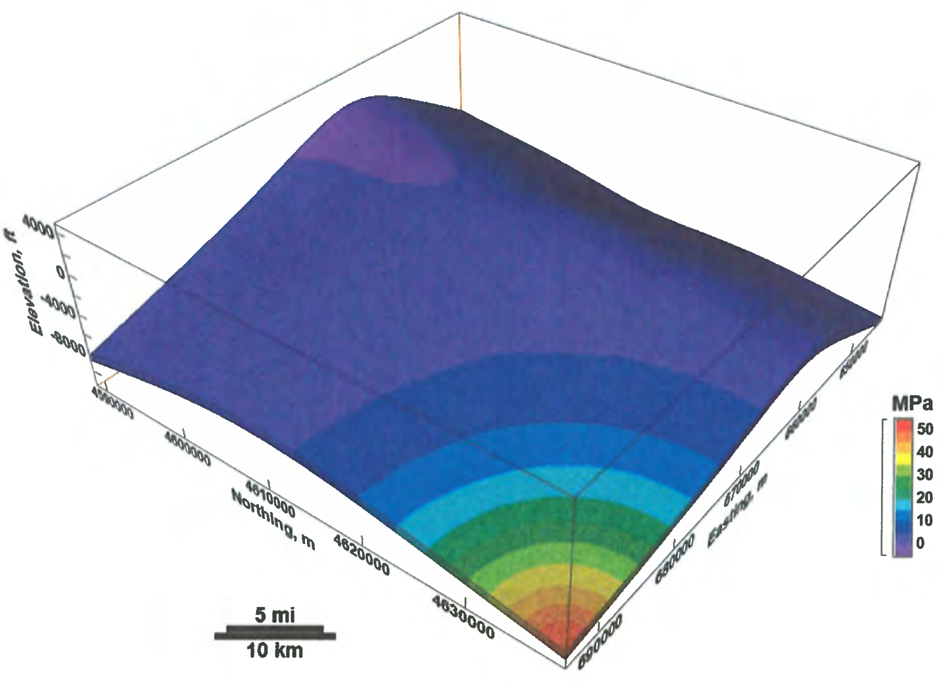


Figure 18. Results of a numerical simulation of the displaced fluid plume caused by injection of 750 Mt CO_2 into the Weber Sandstone over a 50-year period. The simulation region is 50 km × 50 km. Nine wells were used to inject 15 Mt of CO_2 per year. After 50 years of injection, the formation pressure increased by 1 MPa (145 psi) 50 km (31 miles) up-dip from the injection site.

The WSGS suggests that the fluids displaced during CO_2 injection could be managed via an integrated CO_2 sequestration/fluid production and treatment system (**Figure 19**). For example, a nine-injector-well field could be surrounded by at least four fluid production wells, each located 2 km from the injection well field (**Figure 20**). If 15 million tons of CO_2 is injected annually into the Weber Sandstone (with an injection interval of 500 feet, porosity of 10 percent, relative permeability of 1 md, and an injection rate of 53 kg/s for each injection well), approximately 80 million barrels of fluid would be displaced each year for 75 years. In the suggested strategy, this 80 million barrels of fluid would be produced and treated at the surface (**Figure 19**). Treatment is necessary: Lindor-Lunsford et al. (1989) showed that the salinity concentrations (TDS) in groundwater in the Upper Paleozoic aquifers on the Rock Springs Uplift generally exceed 30,000 mg/L.

In treating this formation fluid at a reverse osmosis treatment plant, or using other desalination techniques, approximately 10 percent of the fluid will remain as brine concentrate that can be injected offsite into the subsurface, or stored at the surface. Treating the fluid will yield approximately 10,000 acre-feet of potable water per year, which could be used by an adjacent power plant; by the community of Rock Springs, Wyoming; as replacement water in the Upper Colorado River drainage; or perhaps by communities along the Colorado Front Range. The heat associated with the produced brines (100°C–130°C) could be used to generate power for either the power plant and/or the water treatment plant.

The feasibility of such a large-scale desalination endeavor is demonstrated by desalination projects in Israel: there, desalination plants produce 2 million barrels of potable water per day – 13 percent of the country's annual water consumption (www.water-technology.net/projects/israel).

Conclusions

Numerical simulations – using real rock/fluid system characteristics – demonstrate that it is feasible to inject 15 Mt of CO_2 per year for 50 years into the Weber Sandstone on the Rock Springs Uplift (a total of 750 Mt CO_2). This volume of CO_2 can be contained beneath a 16 km × 16 km area (the storage domain). Over a 75-year period, this volume of CO_2 will displace one cubic kilometer of fluid. This huge volume of fluid will migrate out of the storage domain, mostly up-dip toward the crest of the structure (**Figure 18**). Consequently, geological CO_2 sequestration on the scale required by a large power plant – either on the Rock Springs Uplift or anywhere else in the Rocky Mountain region – will require displaced fluid management. The Wyoming State Geological Survey proposes an integrated CO_2 sequestration/fluid production/fluid treatment strategy to accomplish CO_2 sequestration on the Rock Springs Uplift. In this strategy, carbon is sequestered on a commercial scale while displaced fluids are produced and treated at the surface. The volume of treated water produced as a result of this strategy represents a highly valuable commodity in arid southwestern Wyoming.

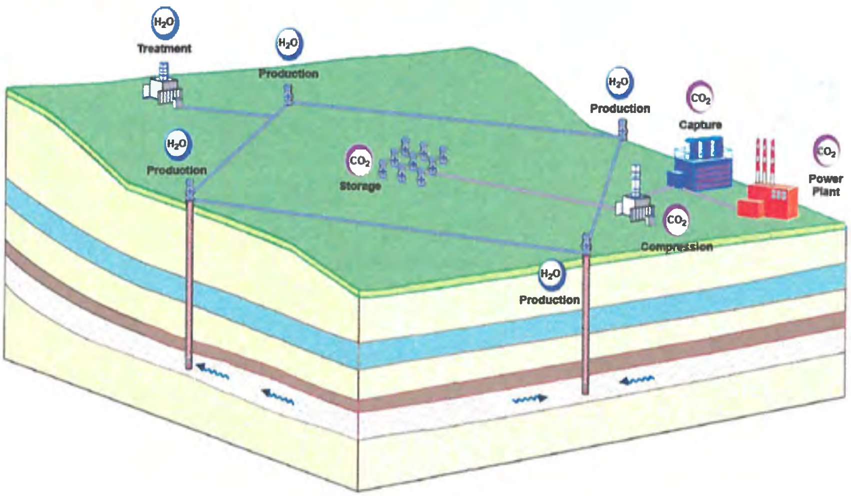


Figure 19. Schematic model of the proposed CO_2 injection/fluid production treatment strategy.

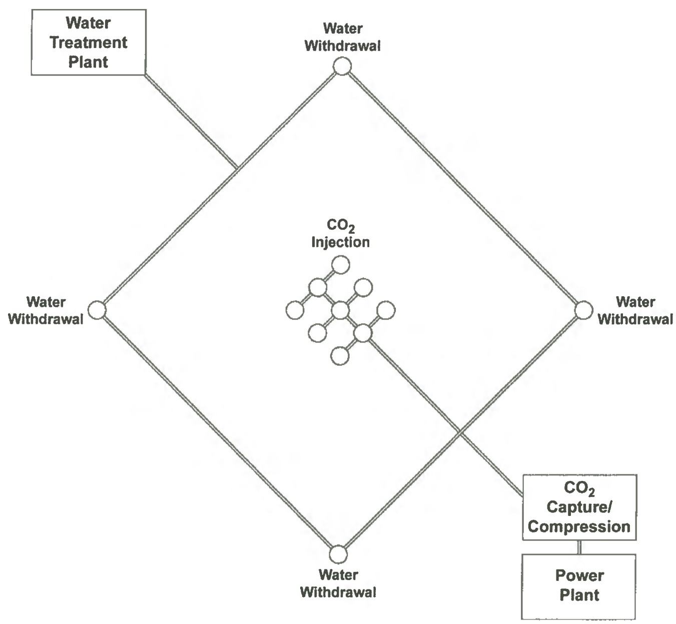


Figure 20. Highly schematic spatial distribution of the proposed CO_2 injection wells (1 Mt CO_2/year) and the four fluid production wells that will produce a total of approximately 586 million gallons of fluid per year. This fluid will be treated at the surface to potable water standards.

The heat associated with the produced brines (100°C–130°C) could be used to generate power for either the power plant and/or the water treatment plant.

The proposed integrated strategy will surely be expensive, but there is presently no viable alternative available in Rocky Mountain basins. Finally, it is important to realize that this proposed strategy will be a test of the whole idea of CO_2 sequestration: if commercial-scale geological CO_2 sequestration cannot be accomplished on the Rock Springs Uplift, it probably cannot be accomplished anywhere in the Rocky Mountain region.

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