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Development of Storage of Captured CO_2 as a New Geoscience Business—Focus on the Gulf Coast

Susan D. Hovorka and Ramón H. Treviño

Bureau of Economic Geology, Jackson School of Geosciences,
University of Texas at Austin, Austin, Texas 78758

ABSTRACT

Expertise in the science and best practices of injecting CO_2 for permanent storage has been growing for about 30 years. Many techniques are mature and ready to support the commitments of governments and businesses globally. Diverse facilities have combustion or process engineering activities that now produce large volumes of CO_2 and release it to atmosphere; mitigation is needed. Carbon capture and storage (CCS) allows capturing CO_2 at these point sources and injecting the captured CO_2 into porous sedimentary rocks beneath and effectively isolated from groundwater resources for permanent storage.

Storage of CO_2 is built on geotechnical approaches used for over a century for hydrocarbon and groundwater production, brine and other waste fluid injection, and injection of CO_2 and other fluids for secondary and tertiary recovery. However, injection of CO_2 for long-term storage requires several new ways of using geotechnical skills. New skills have been developed and tested in a series of studies and tests described, herein. For example, the DOE–funded Frio test in Liberty County, TX, and the SECARB early test at Cranfield Field, MS, assessed multiple methods of documenting multiphase flow using geophysical and geochemical tools and developed new approaches for environmental assurance monitoring in soils and groundwater. Studies at West Ranch and Hastings Fields, TX, have tested methods for assuring retention in areas with dense well penetrations. These US–based onshore projects are linked to dozens of international projects and to newly developing projects both onshore and offshore. Together, this experience builds confidence in methods for selection of geologic sites that will accept and retain large volumes of CO_2. In addition, methods for documenting that the modeling assumptions made during site selection are vali-

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dated by monitoring have been robustly tested. We document progress and highlight areas where future improvement will add value.

INTRODUCTION

Interaction of the geosystem with the atmosphere and hydrosphere is dynamic, from slow moving plate tectonic and sedimentologic cycles to rapid interaction of atmosphere with the ocean, plants, soils, and animals. Over the past century, development of mining and drilling techniques have made access to the deep subsurface more dynamic, facilitating large and increasing amounts of extraction of coal, oil, and gas. Combustion of these resources has provided large amounts of high value energy. However, a side effect has been the rapid release of large amounts of carbon formerly stored in the Earth's crust. Carbon release is in the form of the combustion by-product carbon dioxide (CO_2) into the atmosphere and from atmosphere into the ocean. Concentration measurements show that the sudden increase exceeds the capacity of natural removal processes such as photosynthesis, weathering, or carbonate precipitation to remove CO_2 from the atmosphere and ocean system (IPPC, 2021). The impacts of concentration increases are found to be problematic, incentivizing current business and policy needs for development and deployment of many techniques to avoid or mitigate the release of CO_2 (International Energy Agency, 2021; IPPC, 2021).

The technique to avoid release selected for review in this paper is a simple idea: after extraction of energy from fuels, reinject the CO_2 back into the subsurface either from the point of release (a facility) or at higher cost capturing it from the air after release. Re-emplacement of carbon can be directed back where it came from by injecting CO_2 into depleted hydrocarbon fields. Larger volumes of CO_2 can be injected into subsurface environments similar to hydrocarbon fields, which have a reservoir and seal but which did not receive or retain hydrocarbon charge, a setting referred to as "deep saline storage" because the pore spaces are filled with brine. In detail, this mitigation technique, known as carbon capture and storage (CCS) is a complex multifaceted process similar in many was to the businesses of hydrocarbon extraction. This paper is a review of geotechnical similarities and differences.

It may be appropriate to compare this solution to past mitigations such as waste water treatment. Prior to the environmental laws of the 1970s releases of wastewater resulted in serious contamination of surface and groundwater (EPA, 2021). The Safe Drinking Water Act (SDWA) and other environmental laws restricted release. Individuals, companies, industries and municipalities had to find ways to avoid release of low quality water. Mitigations included waste water clean-up and release, deep well injection (under the Underground Injection Control [UIC] program), closed systems that did not release water, and finding alternative processes. The cost of waste-water handling remains substantive; however, it has become a normal part of responsible business to avoid release that damages water. The authors hope that papers such as this one will help develop similar mitigations for CO_2 release that will continue to advance to similar or greater levels of compliance.

METHODS

The sources of information in this paper include studies conducted since 1999 by the Gulf Coast Carbon Center (Fig. 1) and extensive learnings from technical interactions of many sources from colleagues in the US and globally.

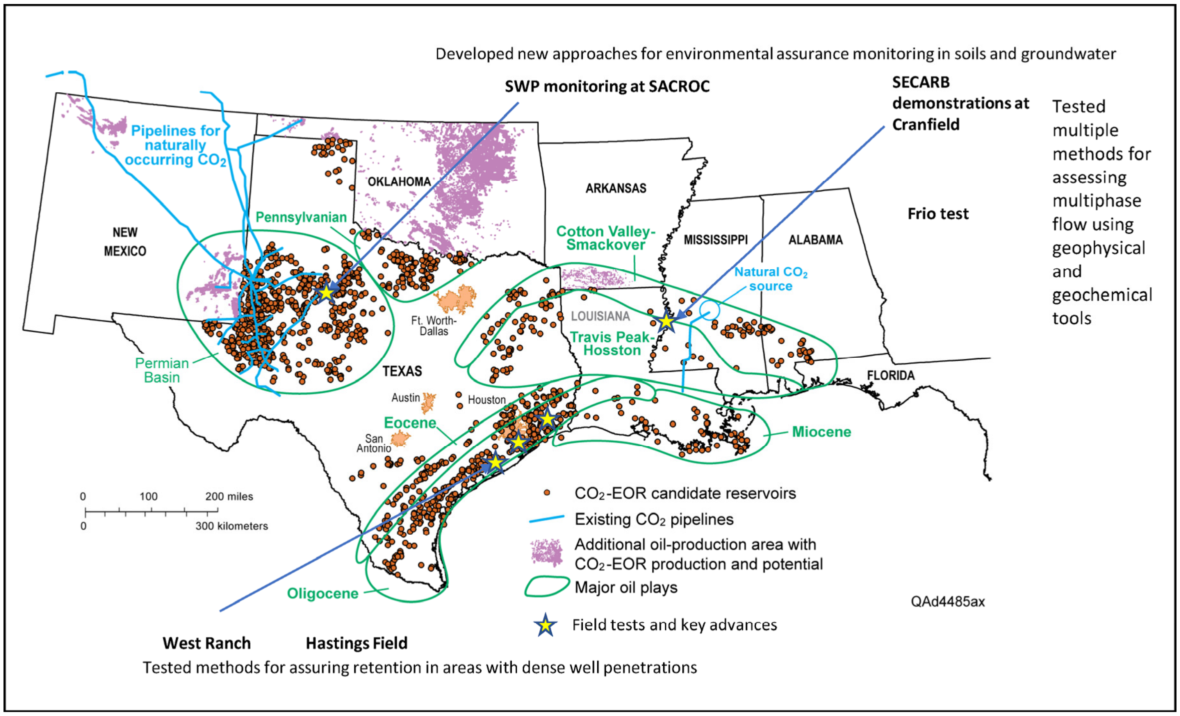

Figure 1. Field test sites and major experiments conducted. Base map from Ambrose et al. (2008).

RESULTS

Injecting CO_2 for permanent storage can be conceptualized in four interrelated categories. We compare the new CO_2 storage business to traditional geoscience applications for each category (Fig. 2).

Project conceptualization includes identifying geologic storage resources and matching them to point sources from which large volumes of CO_2 can be captured. The match requires consideration of all the system components in terms of volumes captured, compressed, transported and injected, the cost of these components, and the value to be gained. In the US, the current value of CO_2 storage is derived from the 45Q tax credit or from credits from the California Low Carbon Fuel Standard (LCFS). Additional mechanisms may become relevant in the future. The project conceptualization skill set is similar in some ways to that used to explore and make investment decisions for hydrocarbons extraction in that it combines geotechnical screening with business development and finance elements. Observed differences are that storage resource is more abundant that hydrocarbon resources by a factor of 10 to 100 (calculated from data in the National Energy Technology Laboratory [2015]). High capital cost for both capture and transportation and operating cost in terms of energy penalty for capture operations also shifts the value proposition toward finding "good enough" storage closer to sources. Super-giant storage may not be as attractive as lower capacity storage with reduced transportation investment.

Storage complex characterization, modeling, and engineering follows a successful project conceptualization. Geologic details about the properties and geometry of the reservoir flow unit are collected using techniques identical to those used in characterization and engineering design of a discovered hydrocarbon reservoir, such as collecting 2D or 3D seismic, drilling, logging, and coring wells, evaluating the results in terms of petrophysics, single and multiphase

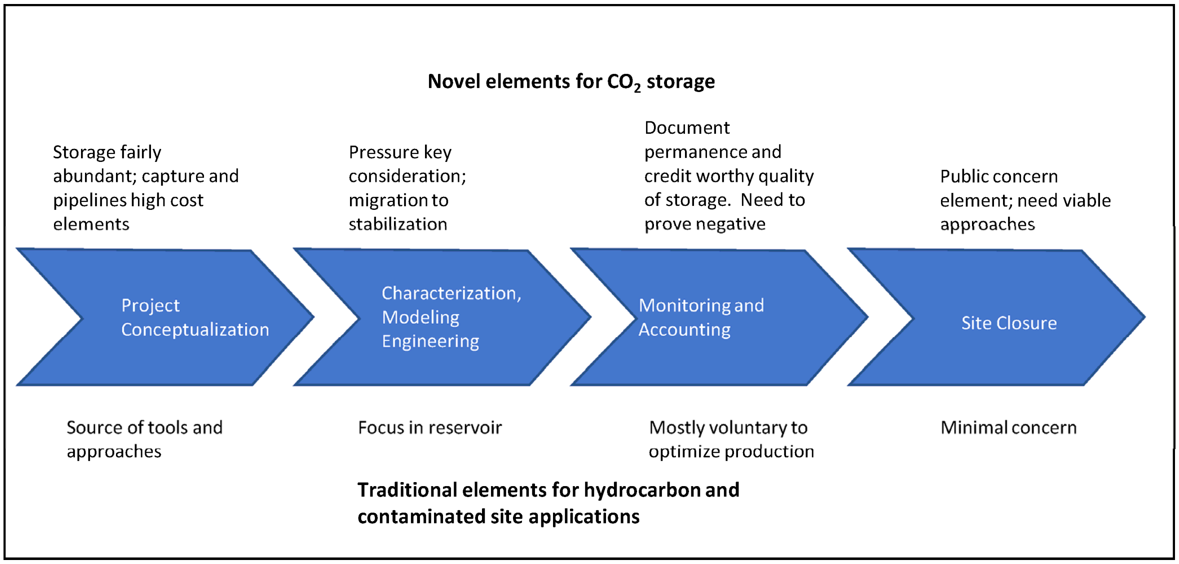

Figure 2. Components of a CO_2 storage project showing novel (top row) and well-established (bottom row) elements.

flow properties, and using facies interpretations to evaluate lateral continuity of flow zone and confining intervals. Differences include less detail needed at the interwell scale and more attention to pressure response. Because injection into a deep saline formation is a "one way trip" with no production, pressure increase is a limiting parameter. To preserve the integrity of the confining geologic system and avoid inducing seismicity, injection wells in the UIC program are operated below fracture pressure. Therefore, wells must be spaced far enough apart so they do not pressure-interfere and limit injectivity. Boundary conditions such as faults or facies changes that limit flow well away from the injection sites are important in determining the rate and magnitude of pressure build up (Ganjdanesh and Hosseini, 2018). In addition, the area where pressure is elevated as a result of injection, known as area of review (AOR), is an important well-permitting issue. The AOR is the area of pressure increase sufficient that, if there was an open conduit such as an unprepared wells, formation brine would be lifted into fresh water, damaging resources. Therefore, all wells in the AOR must be managed so that isolation of the injection zone from fresh water is assured.

The details of the facies architecture are very important in CO_2 injection but at different locations than in hydrocarbon production. In production, locating wells and perforated intervals to effectively access the hydrocarbon is essential. However, in CO_2 injection the efficiency of CO_2 occupancy matters' however, understanding issues such as long-term CO_2 migration under buoyancy, wettability and capillary entry pressure of both flow units, and flow barriers is essential to assure that the CO_2 is trapped permanently and does not migrate out the of the storage complex (trespass) or encounter leakage pathways is essential.

Many other differences with hydrocarbon production can be noted, such as the need to use materials that are acceptable in CO_2 service; however, these fall close to normal engineering practices. When CO_2 is injected for enhanced oil recovery (CO_2 EOR), the characterization, modeling, and engineering are more similar to that needed for hydrocarbon production.

Monitoring and accounting for the injected CO_2. In hydrocarbon production, surveillance such as logging, pressure measurement, and geophysical surveys may be done to optimize the recovery. However, only a few parameters are reported to the oil and gas regulator. Conversely, CO_2 storage has heavy monitoring and reporting requirements and expectations. Four drivers create this difference: (1) storage permanence in terms of isolation from the atmosphere is the goal; therefore, good documentation of the amount of CO_2 injected and compelling evidence that it is retained where it was emplaced are needed; (2) the regulatory environment for CO_2 injection (EPA Class VI under the UIC program and state primacy that is equally stringent) was developed recently, and societal expectations that industries will meet high environmental standards has become widespread; (3) storage of CO_2 may be more difficult to assure than other fluids because CO_2 is buoyant, is of low viscosity, expands as is migrates upward (i.e., changes from a dense fluid to a gas), and may be injected in areas that have not been tested by trapping hydrocarbons; and (4) an expectation has developed in the CCS community that accepts the need of monitoring.

Most geotechnical monitoring in the past has involved contaminated sites where the known plume is assessed for remediation. Monitoring of CO_2 storage is different from this norm because it needs to demonstrate a negative—that the CO_2 plume is not behaving in unacceptable ways and that no CO_2 is leaving the intended storage area. In order to clearly demonstrate something is not happening requires a good design that systematically eliminates the unacceptable outcomes. In the reservoir, this can be achieved by modeling unacceptable outcomes and then collecting the monitoring data to show that such events are not occurring. (Hovorka, 2017). For example, the CO_2 plume might access only one layer and therefore migrate farther in the layer than expected. Documenting that CO_2 is distributed in many layers could eliminate this concern more effectively than trying to detect a thin widespread zone.

In some cases, a difficult expectation is established (i.e., to document that no leakage to near-surface has occurred). CO_2 is very active in the near surface; therefore concentrations in soil, groundwater and atmosphere vary temporally and spatially with long duration trends related to changes in climate and land use. In addition, in CO_2 leakage at natural analogs and controlled releases (proxy leakage), the CO_2 can be focused in small areas that may be only a few meters across. We suggest that expectation of detecting leakage at the surface should be reduced, and effort should be focused on attributing leakage signal from an incident or allegation (Dixon and Romanak, 2015).

Site closure. For hydrocarbons, ending production is a relatively simple mater of plugging and abandoning wells to meet the regulatory standards and surface clean-up to meet lease requirements. Activities after the end of CO_2 injection are required in Class VI and the LCFS. However the effective approaches to meeting these expectations need refinement. The requirements for so-called Post Injection Site Care (PISC) arise from generally non-technically based concerns (e.g., that unwatched subsurface will spring leaks) or via comparison to CO_2 storage in biomass. CO_2 stored as biomass has a risk of release as a result of fire or other damage to the forest. No analog exists for the subsurface. Additional work is needed to merge a technical understanding with the social concern.

SUMMARY AND CONCLUSIONS

Technical skills to mitigate carbon release to atmosphere are well supported by adaptation of well-established geotechnical skills. A comparison of activities needed to support storage with hydrocarbon and contaminated-site skills shows the adaptation required. Growing concern with release of CO_2 has begun to translate to willingness-to-pay mechanisms, which has spurred business interests.

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