

Area of Review: How large is large enough for carbon storage?

Jean-Philippe Nicot¹, Susan D. Hovorka¹, Paul R. Knox², and Thet Naing²

¹The Gulf Coast Carbon Center, Bureau of Economic Geology, Jackson School of Geosciences
The University of Texas at Austin, Box X, Austin Texas 78713

²previously at Bureau of Economic Geology, Jackson School of Geosciences
The University of Texas at Austin, Box X, Austin Texas 78713

ABSTRACT

The Texas Gulf Coast is an attractive target for carbon storage. Stacked sand-shale layers provide large potential storage volumes and defense-in-depth leakage protection. However, multiple perforations resulting from intensive hydrocarbon exploration and production have weakened seal integrity in many favorable locations. If the ultimate goal of carbon storage is to isolate large volumes of CO₂ for hundreds to thousands of years, plume migration will encounter inadequately completed wells miles away from the injection zone. Moreover, the detrimental impact of CO₂ on cement could undermine the structural integrity of all contacted wells, although pressure effects subside quickly after injection. Even wells abandoned to current standards cannot be guaranteed leak-free in the long term. We describe spatial statistics extracted from the Texas RRC Well Bore database as applied to carbon storage.

Although the Area of Review (AOR) has been traditionally defined by a fixed radius with the strong regulatory requirement that the injectate stays within the injection layer, buoyancy is a major characteristic of CO₂ that introduces a third dimension into the Area of Review process. Using simple geological mapping to characterize structural traps, we determine the likely pathway and the contacted volume of a migrating plume. The latter can be as large as a fault compartment with dimensions of 20 km × 20 km. However, the contacted volume is ultimately a function of the total injected volume, and the specifics of each project should dictate the dimensions of the zone of endangering influence (ZEI).

An option, viable for the Texas Gulf Coast, to reduce geologic uncertainty, to decrease the impact of wells, and to limit the amount of information to be collected, is to inject CO₂ below the maximum penetration of most wells.

Biographic Sketch:

Jean-Philippe (JP) Nicot works for the Bureau of Economic Geology, John A. and Katherine G. Jackson School of Geosciences, The University of Texas at Austin, University Station Box X, Austin, Texas 78713-8924, U.S.A.; Tel. 512-471-1534; Fax: 512-471-0140; email: jp.nicot@beg.utexas.edu. JP has a Ph.D. in Civil Engineering from The University of Texas at Austin. His current interests include hydrogeological aspects of carbon storage and brackish water desalination.

Geological sequestration of CO₂ (also called carbon storage) has been recognized as an important way to mitigate increase in atmospheric CO₂ (IPCC, 2005, Chapter 5) and has been touted as a way to address global warming. Injection of CO₂ has the additional benefit of aiding in oil recovery (Enhanced Oil Recovery, EOR), as well as enhancing coalbed methane recovery (ECBMR) because CO₂ sorbs more strongly to coal than methane does. Legislation and regulations for EOR and ECBMR are already in place addressing important operational issues of the injection phase. This study focuses on some of the technical underpinnings relating permitting to long-term (hundreds to thousands of years) postclosure migration of CO₂ in the subsurface, using the Texas Gulf Coast as an example. The emphasis on Texas is appropriate because of the abundance of saline aquifer candidates in the Texas Gulf Coast (Hovorka et al., 2000), and about half of the electric power in Texas is generated by coal-fired power plants often located above those formations. Another reason to focus on the Gulf Coast is that many reservoirs are susceptible to CO₂ flooding (Holtz et al., 2001). Historically, for a variety of reasons (e.g., CO₂ availability via pipelines primarily developed to the Permian Basin), most CO₂ floods in the state have taken place in West Texas and far fewer in the Gulf Coast. The Texas lignite belt is also located in the Gulf Coast area but farther inland. The concept of stacked storage makes it likely that CO₂ captured from coal-fired power plants could be transported through a pipeline toward the coast, where they are most likely to be used. Another, secondary reason for focusing on the Texas Gulf Coast is that it has a very low level of seismic activity and is not a credible candidate for any type of volcanic or tectonic activity in the near future.

Central to all industrial projects is the permitting process, particularly its cost and what it involves in terms of time investment. The current regulatory framework covers all aspects of the injection phase with two goals: to protect the water resources and to protect hydrocarbons and other resources that could be produced in the future (e.g., geothermal energy). Any CO₂ storage project needs to address these two issues, but in addition it must guarantee that CO₂ will be reasonably sequestered in the long term in order to be effective in obtaining the reduction in atmospheric concentrations. This latter requirement could translate into additional constraints in the permitting process or additional assurance required to make the CO₂ credits fungible. This paper focuses on its significance for the Area of Review (AOR).

Overview of Relevant Current Rules

Area of Review Dimensions

The 40 CFR, Underground Injection Control Program (UIC) defines AOR in §146.03 as “the area surrounding an injection well described according to the criteria set forth in §146.06 or in the case of an area permit, the project area plus a circumscribing area the width of which is either ¼ of a mile or a number calculated according to the criteria set forth in §146.06.” Within the AOR, before starting any injection, an operator must identify all wells penetrating the injection zone or the confining zone (§146.64) and assess their status for possible corrective action. The overarching purpose of the AOR is protection of drinking water resources due to pressure buildup in the injection zone. Drinking water resources, also called *underground source of drinking water* (USDW), are defined in §146.03 as a formation with water quality below 10,000 mg/L total dissolved solids. Section §146.06 states that the AOR should be determined for each well or field through either a *zone of endangering influence* (ZEI) or a fixed radius, which cannot be smaller than ¼ mile. The radius of the ZEI is calculated as the lateral distance in which the pressures in the injection zone may cause migration of the injection and/or formation fluid into a USDW. The State of Texas, a primacy state, is responsible for applying the provisions of the UIC program (§ 147.2200 and § 147.22010, 40 CFR). The general statutes of 40 CFR, Part 144, have transferred with little change to the Texas Administrative Code (TAC).

In Texas, as in most of the U.S., the fixed radius method is overwhelmingly used and is ¼ mile for Class II, III, and V wells and 2.5 miles for Class I wells (Rule §331.42, Title 30 and Rule §3.9, Title 16, Part1, TAC, 2006). Current requirements from the Railroad Commission of Texas for Class II wells (RRC, 2006) include making best efforts to identify all wells in a ¼-mile radius of the proposed injection well and to provide evidence that all abandoned wells intersecting the injection formation have been plugged. In some circumstances, this radius can be increased to ½ mile (shallow disposal wells in the

Barnett Shale area of North-Central Texas). Class V includes all injection wells not in Classes I through IV. The wells are, in general, built into aquifers, and they, by definition, do not endanger USDW's; that is, the injectate does not violate any drinking-water standards.

Confinement

By essence, Class I and II well operators need to make a strong case that the injectate will not leave the injection layer. This requirement is legally true for Class I wells but also true in practice for Class II injection wells. The requirement will be difficult to absolutely abide by with a buoyant fluid like CO₂. Other buoyant fluids like oil and gas are retained in traps in the subsurface for geologic periods of time, however many of these traps leak slightly so that it is possible to explore for oil and gas reservoirs by searching for subtle anomalies in soil gas composition or other geochemical signatures.

Fluid Composition

The regulations state that "All well materials must be compatible with fluids with which the materials may be expected to come into contact" (Rule §331.62, TAC, 2006, for Class I). However, the problem lies not with future wells that can be designed to accommodate the presence of CO₂ but with the hundreds of thousands of wells not constructed to withstand its aggressiveness.

Monitoring

During the operational phase, monitoring of the injection well is always required, particularly pressure on the annulus. Monitoring of water quality in the lowermost USDW and in the first aquifer overlying the injection zone can also be required (Rule §331.63g, TAC, 2006) for Class I wells. This monitoring must take place "until pressure in the injection zone decays to the point that the well's cone of influence no longer intersects the base of the lowermost USDW or freshwater aquifer" (Rule §331.68b, TAC, 2006, for Class I). Monitoring of the USDW is rarely undertaken in Texas for Class I and is not required for Class II wells (Platt, 1998). Monitoring wells, especially if located upgradient in the injection horizon, may turn out to be an additional leakage pathway.

Variance from the Area of Review

A variance from AOR requirements can be granted to a field or other area if an applicant can prove that the variance will not result in a material increase in the risk of fluid movement into groundwater or to the ground surface. This proof can be demonstrated by (1) showing that reservoir pressure is insufficient to raise fluids to groundwater, (2) showing that geological conditions are present that preclude upward movement of fluids, or (3) other compelling evidence. Variance is rarely asked for or granted. However, some of the factors relevant for a variance application are also germane to CO₂ migration.

Leakage Pathways

Conduits for leakage to USDW can be natural (faults) or human made (wells). In the case of traditional water injection, hazardous or not, injection pressure is the driving force behind leakage, and mainly faults and wells are of concern. In the case of injection of a buoyant fluid, such as CO₂, gravity forces continue acting, even after dissipation of the pressure pulse. This phenomenon adds a third avenue for leakage, upward connectivity of transmissive zones through, for example, loss of seal integrity, sand-against-sand fault compartments, or spill points where faults die off.

Trapping Mechanisms

Underground carbon storage modes have been organized into four main categories:

- residual or capillary trapping owing to multiphase flow processes,
- solubility trapping through the dissolution of CO₂,
- hydrodynamic trapping, and
- mineral trapping due to the reaction of CO₂ with ambient rocks.

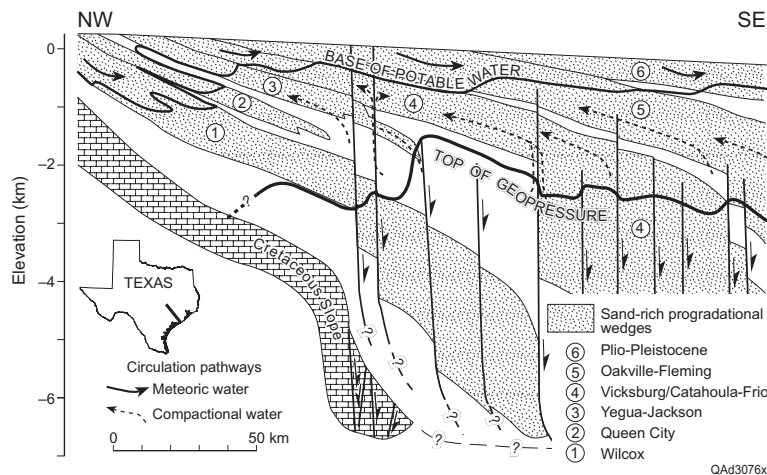
Several studies have suggested that mineral trapping, although representing the ultimate fate of CO₂ in the subsurface, is a slow process and that in a hundreds to thousands of years timeframe, the main

trapping mechanisms are capillary and hydrodynamic. Solubility trapping can be volumetrically significant and rapid but may be limited by surface area between water and CO₂ in some injection geometries. The induced water density change may alter flow dynamics to increase this contact. The capillary trapping mechanism does not perform well if the CO₂ path is cut short intrinsically by fingering or by external features, such as a well or a conductive fault. Similarly hydrodynamic trapping could be ineffective if seals are poor and/or some of the CO₂ could leak at natural spill points.

Carbon Storage Site Configuration along the Texas Gulf Coast

Texas Gulf Coast Geology

A good understanding of the AOR entails a good knowledge of the local geology, and the general geology of the Gulf Coast is simple. It consists of a thick pile (several kilometers) of alternating sandy and clayey layers resulting from the deposition by rivers of their sediments in deltas and farther out in the ocean (Figure 1). The process is still active today (e.g., Mississippi River), and growth faults periodically develop to accommodate accumulation of the enormous mass of sediments. In the northern section of the Texas Gulf Coast, salt domes have been moving upward from the kilometer-thick Louann salt layer, which has resulted in a contrast in oil traps. These traps have, in turn, resulted in carbon storage potential targets, where, in the Houston area, upturned sediments abutting diapirs act as a trap, and, further south in the Corpus Christi area, oil reservoirs are created by more common structural and stratigraphic traps along growth faults. This contrast is visible on a map of oil and gas well surface locations (Figure 2), which are clustered around salt domes in the Houston area and more spread out elsewhere.



Note: Adapted from Galloway (1982) and Galloway et al. (1982)

Figure 1. Southern Gulf Coast major sand-rich progradational packages and growth fault zones beneath the Texas coastal plain.

Local Traps

Despite a general gentle dip toward the Gulf of Mexico, local geometry of the layers does include numerous structural traps, owing to the activity of growth faults and radial faults around salt domes and to the deformation near diapirs. Around salt domes, layers have steep dips. Hydrocarbon accumulations along the Gulf Coast could occur in some of those traps (Figure 3), and production/exploration well density generally follows their pattern.

