

Area of Review: How Large is Large Enough for Carbon Storage?

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

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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.

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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.

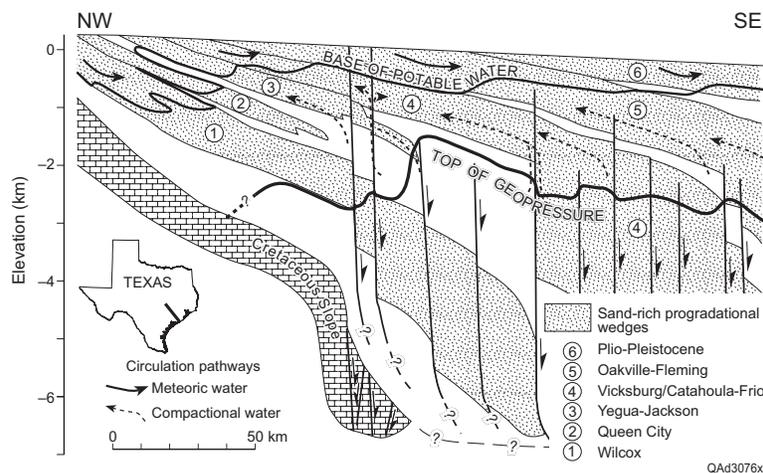
Several studies have suggested that mineral trapping, although representing the ultimate fate of CO₂ in the subsurface, is a slow process and that in a hundreds to thousands of years timeframe, the main

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.

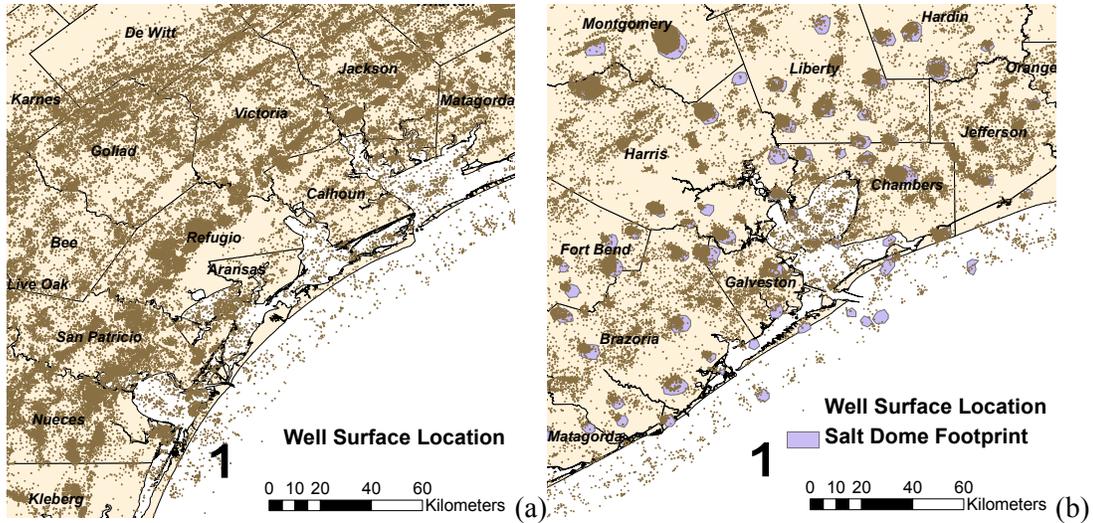


Note: Adapted from Galloway (1982) and Galloway et al. (1982)

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.



Source: RRC "Well" database

Figure 2. Surface well location in the Corpus Christi-Victoria area (a) and in the Houston area (b).

Within the range of buoyancy of most hydrocarbons (more than oil, less than gas), CO₂ will also follow similar pathways and accumulate in similar traps (Figure 4). If the injected volume is larger than the capacity of the first encountered trap, CO₂ will continue to flow upward until it reaches another trap, leaving behind a trail at residual saturation (traps are loaded with CO₂ when water is at residual saturation) (Figure 5). The question of the migration mode, between the end-members of a wide diffuse spreading and of a localized fingering/channeling, remains open. Using a contour map of the top of the Frio (base map purchased by Geomap, Dallas, TX), traps and their fetch area were mapped (Figure 6). Large areas remain blank, not because they lack traps, but because they ultimately lead to a salt dome. A statistical analysis of the distribution of closure and fetch areas is presented in Figure 7. A significant number of traps have an area smaller than 5 square miles but some are very large covering tens of square miles.

Multiple similar maps can be produced for the main formations of the Gulf Coast, with variations from the example presented both because of faults tapering off with depth and toward the surface and because of the increased impact of salt domes with depth.

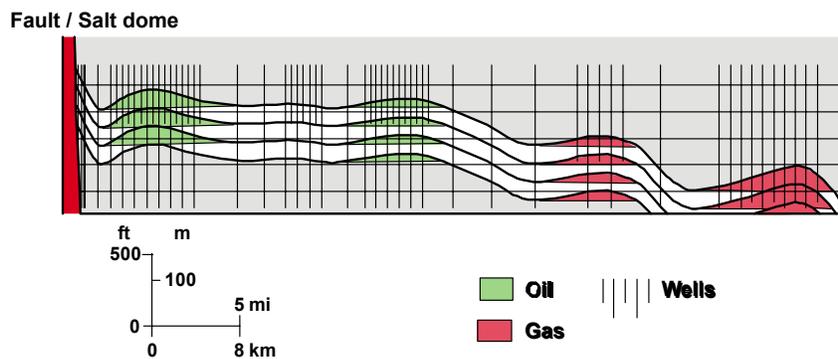


Figure 3. Cartoon of hydrocarbon accumulation in the Texas Gulf Coast.

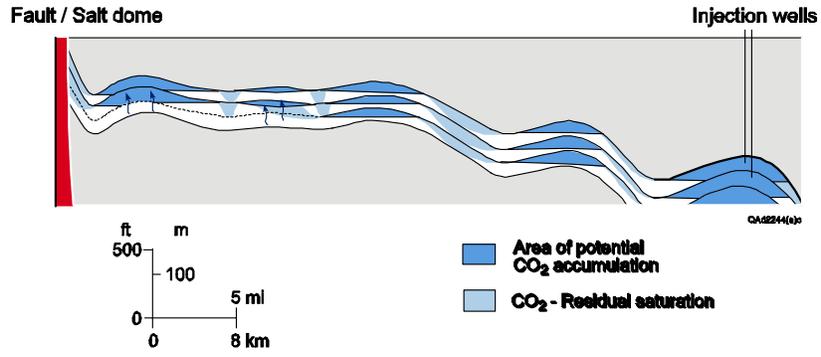


Figure 4. CO₂ travel path and trapping mechanisms.

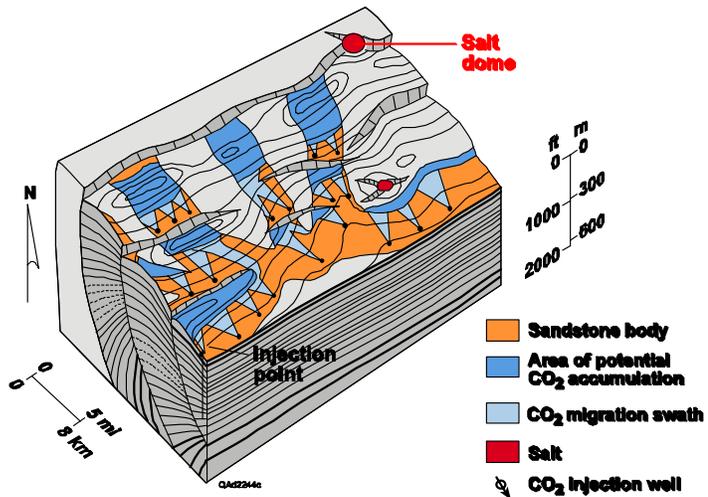


Figure 5. Example of CO₂ migration in a typical Gulf Coast setting.

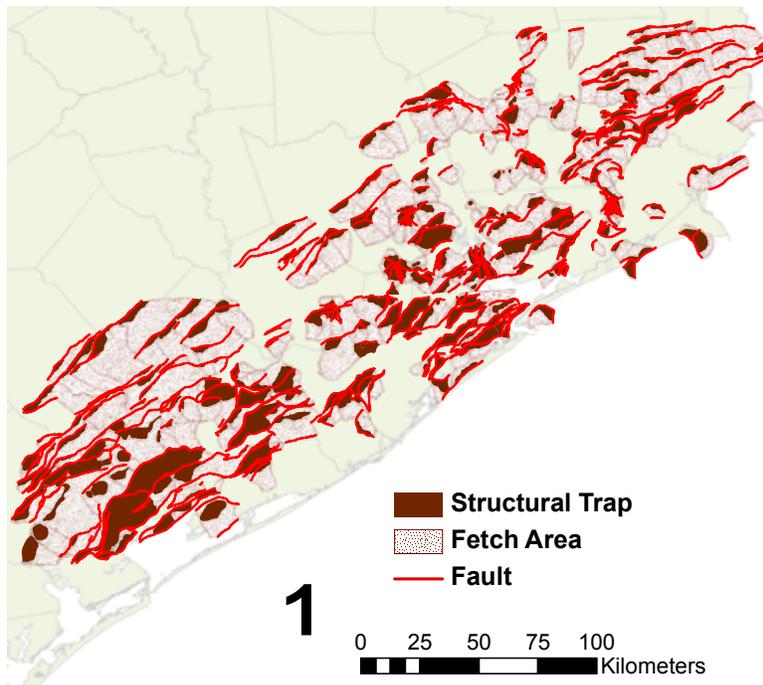


Figure 6. CO₂ trapping on top of the Frio

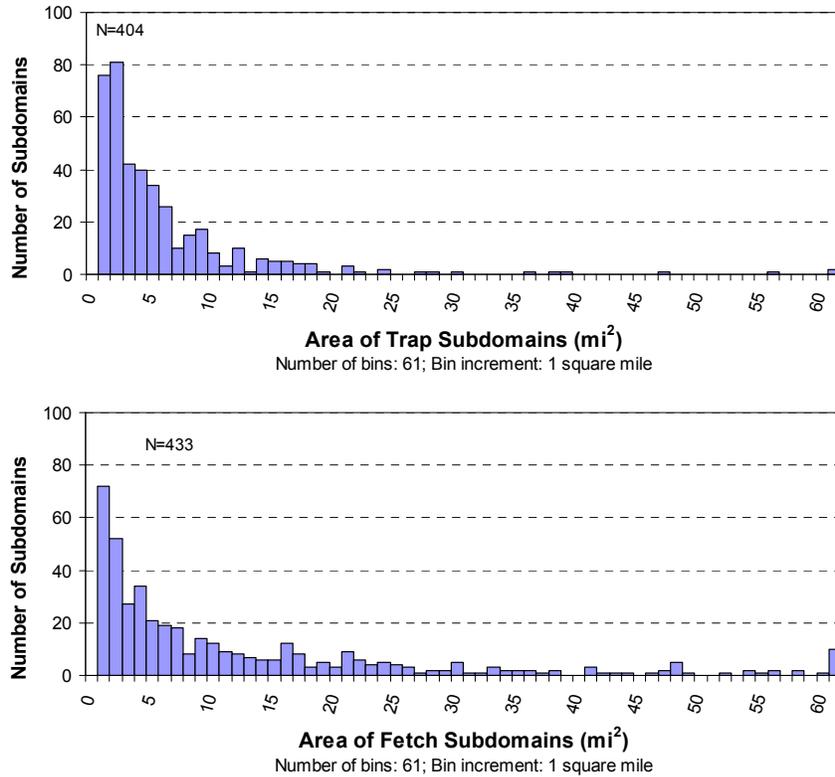


Figure 7. Statistical distribution of trap and fetch subdomains

Tentative Calculation of Local Trap Capacity

A crude computation of the trap capacity (Figure 8) can be performed by assuming that the CO₂ density is 700 kg/m³, that the sand porosity is 30%, that the sand fraction is 30%, that the area is cone-shaped (1/3 of the product of the area by the height), and that the gas saturation is 80%. The trap height is also measured from the contour maps. Figure 8 suggests that most traps will not hold more than 10 million tons of CO₂, amount smaller than the lifetime output of a typical power plant (5 million tons a year for 30 years).

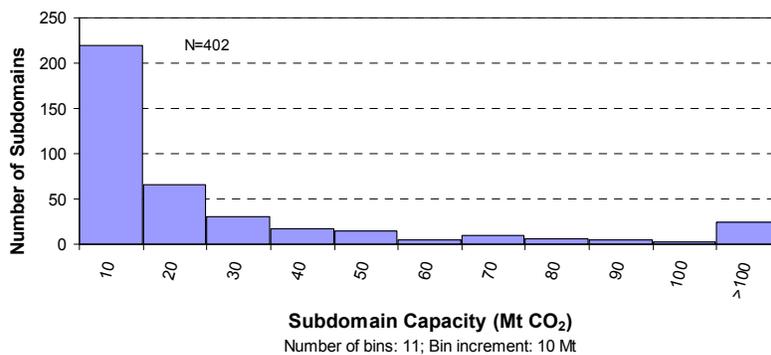


Figure 8. Tentative distribution of trap subdomains

Oil and Gas Fields and Wells

Three main variables relate to well leakage (for all wells, that is, injection, production, and exploratory wells, dry holes, core holes...): well density (how many wells per square area), well depth (how deep the well is and in which formations the completion intervals are), and well age (an older well being more likely to experience leaks in the near term because environmental rules have become

progressively stricter in the 20th century). Approximately 140,000 known wells are in the Tertiary section of the Gulf Coast between Corpus Christi and Houston. About 30% are abandoned wells with plugging records available in electronic form; the remainder comprises of either wells still in operation or wells with no records or records available only in microfilm or paper form. Well density can be extremely high around salt domes, hundreds or even thousands of wells per square kilometer (1 km² ~250 acres) (Figure 8).

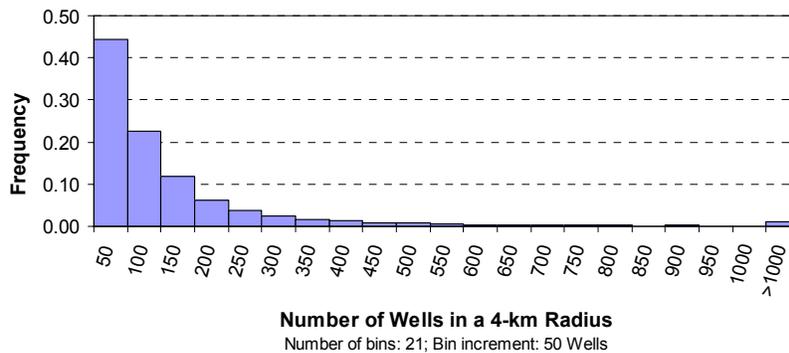


Figure 9. Distribution of well density in the Gulf Coast area (4 km = 2.5 miles)

A Short History of Well Drilling, Plugging, and Abandonment in Texas

Following Warner et al. (1996 and 1997), the RRC well dataset can be sorted into four classes: post-1983, 1983–1967, 1967–1935, and pre-1935, arranged in decreasing order of reliability relative to leakage. The year 1934 saw the first specific plugging rules. They required that the producing formation be plugged with recirculated cement. Before that date, although regulations had existed since the beginning of the century, they were unevenly enforced. The years 1967 and 1983 were also marked by major improvements of well-abandonment rules. Warner et al. (1996) stated that there is a high probability that post-1967 wells have been properly plugged. However, the insurance of a good plugging job does not guarantee the integrity of the well relative to CO₂. Current studies show that CO₂ could degrade enough of a cement plug to create an escape pathway. Even wells abandoned to current standards cannot be guaranteed leak-free in the long term. It is not even certain that their long-term probability of leakage is smaller than that of wells drilled in the late 19th century, although short-term (decades) leakage probability is likely less.

Siting Considerations

An important factor to consider in the siting of a carbon storage facility should be to avoid well bores that represent the most direct conduit to the USDW and the ground surface. Most faults, particularly growth faults, do not reach the surface. In the Texas Gulf Coast, the best way to achieve this goal is to establish the primary injection level below the total depth of most wells. The general trend in the past century has been to drill deeper and tap deeper hydrocarbon accumulations (Figure 10). The number of fields discovered closely follows production. Oil and gas production peaked in the 1960’s followed by a slump in the 1970’s, then by another peak in the 1980’s, followed by a decrease than still continues today. Water wells are generally much shallower, generally above 2,000 ft, (Figure 11) and do not present a problem. The base of the USDW is variable but is generally located in the 2,000 – 3,000 ft range.

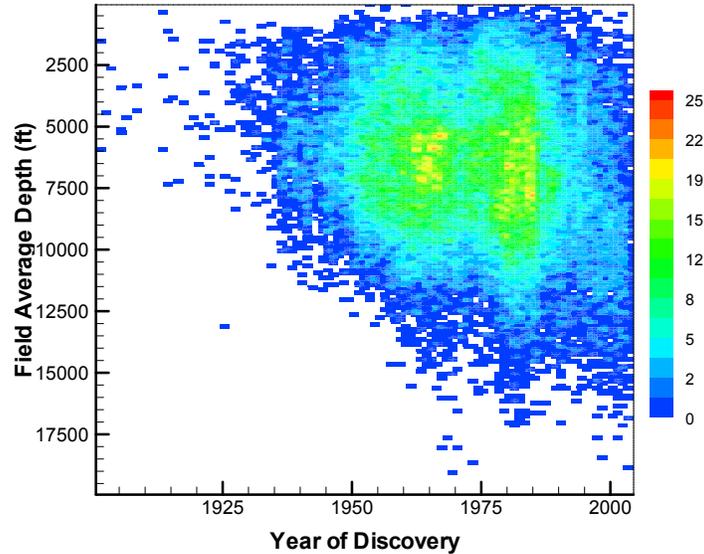


Figure 10. Average depth vs. year of discovery for fields of RRC districts 2, 3, and 4. Key is in number of fields / year / 100 ft

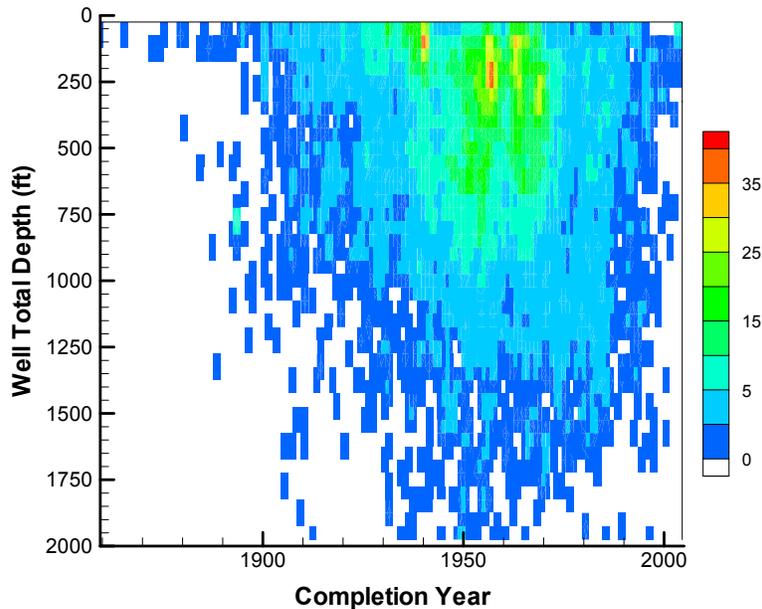


Figure 11. Total well depth vs. completion for water wells (data from TWDB). Key is in number of wells / year / 50 ft

Leakage

Few data concern well leakage (and even fewer concern fault leakage), although numerous instances of anecdotal evidence exist. Paine et al. (1999), when investigating shallow groundwater and surface-water salinization problems in West Texas, concluded that a significant fraction came from leaking wells. A shallow formation (Coleman Junction Formation in the Permian Basin) located about ~800 ft bgs is artesian, which could be considered mimicking pressure increase due to CO₂ injection. Most of the wells are from 20-30's through the 60's. A total of 39 geophysical anomalies fit the profile of a leaking well and at least 718 wells are in the area. Approximately 39 out of 718 known wells are leaking or have leaked in the past (~5%). Leakage rates are even harder to characterize.

Discussion and Conclusions

Some EPA offices are questioning the adequacy of a fixed radius for traditional injection wells (Frazier et al., 2004), which can certainly be justified in the case of CO₂ injection. A fixed radius of influence seems impractical and would in most cases be larger than the Class I 2.5 miles. The typical elongated shape of a trap does not fit well with a circular area of review. The usual requirement / assumption that the injectate not leave the injection horizon (Class I to III wells) is probably unreasonable. The strong buoyancy of the CO₂ and the additional leakage pathway add a vertical dimension, in addition to the two customary lateral dimensions, to the area of review that truly becomes a “volume of review.” However, this does not mean that CO₂ cannot be safely sequestered underground. Even in case of leakage, imperfect geologic storage of the CO₂, currently emitted in the atmosphere and partially stored in ocean, would help in meeting the fundamental goal of carbon sequestration.

An additional element specific to carbon storage, especially in the Gulf Coast, is the impact of nonvoluntary CO₂ invasion of hydrocarbon accumulation. Carbon-dioxide floods are efficient because of the ability of CO₂ to mobilize oil. Just as noncontrolled oil mobilization could lead to the loss of the resource, so too could dilution of natural gas by CO₂ diminish the economic potential of a gas reservoir.

Non-controlled oil mobilization could lead to unanticipated redistribution of the resource. Leakage into a reservoir not intended to be on flood would result in rapid production of the leaked CO₂ to the atmosphere. Similarly, dilution of natural gas by CO₂ would diminish the economic potential of a gas reservoir.

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