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Regulating the Ultimate Sink: Managing the Risks of Geologic CO_2 Storage

ELIZABETH J. WILSON,*,†,‡ TIMOTHY L. JOHNSON,†,§ AND DAVID W. KEITH†

Department of Engineering and Public Policy, 129 Baker Hall, Carnegie Mellon University, Pittsburgh, Pennsylvania 15213, and U.S. EPA National Risk Management Research Laboratory, Research Triangle Park, North Carolina 27711

The geologic storage (GS) of carbon dioxide (CO_2) is emerging as an important tool for managing carbon. While this Journal recently published an excellent review of GS technology (Bruant, R. G.; Guswa, A. J.; Celia, M. A.; Peters, C. A. *Environ. Sci. Technol.* **2002**, *36*, 240A−245A), few studies have explored the regulatory environment for GS or have compared it with current underground injection experience. We review the risks and regulatory history of deep underground injection on the U.S. mainland and surrounding continental shelf. Our treatment is selective, focusing on the technical and regulatory aspects that are most likely to be important in assessing and managing the risks of GS. We also describe current underground injection activities and explore how these are now regulated.

Introduction

With increasing international concern over CO_2-induced climate change, CO_2 capture and sequestration (CCS) is rapidly emerging as a potentially important tool for managing CO_2 emissions. The CO_2 from combustion of fossil fuels or biomass could be captured at electric power plants, hydrogen production facilities, or other industrial processes and sequestered in geologic formations, the ocean, or through the production of stable carbonates on the surface (*1*, *2*, *3*). Because of its compatibility with the current fossil energy infrastructure, CCS may prove an important tool for achieving deep reductions in emissions at a reasonable cost. We focus on geologic sequestration (GS), which we define as the process of injecting CO_2 into deep (greater than ~1 km) geologic formations for the explicit purpose of avoiding atmospheric emission of CO_2. A list of acronyms is presented in Table 1.

Numerous studies have explored the technical aspects of GS (*4*), but there are few assessments of the regulatory environment for GS (*5*). While GS will not likely serve as a large-scale means of CO_2 mitigation for decades to come, action is beginning now. One large GS project is already in operation (*2*), and more are being planned around the world. In addition, facilities that currently inject CO_2 for other purposes are seeking to claim credit for avoided CO_2 emissions. While large-scale use of GS in the electric sector will not occur until government policy imposes significant constraints on CO_2 emissions, there are near-zero cost opportunities for GS in the oil and gas sector that may well be implemented rapidly in response to modest carbon prices.

TABLE 1. Acronyms

CCS	carbon capture and storage
CO_2	carbon dioxide
EOR	enhanced oil recovery
CWA	Clean Water Act
EHS	environmental health and safety
EPA	U.S. Environmental Protection Agency
GHG	greenhouse gas
GS	geologic sequestration
MMS	Minerals Management Service
OCS	outer continental shelf
SDWA	Safe Drinking Water Act
UNCLOS	United Nations Convention on the Law of the Sea
USDW	underground source of drinking water

Because of the likelihood of early action in niche applications, efforts to understand and adapt the regulatory environment for GS cannot wait until the technology is ready for large-scale application. Regulations often evolve incrementally from existing regulatory structures and experience, an effect that often dictates much of the initial regulatory framework. Absent adequate understanding and debate about the appropriate regulatory environment, there is a risk that regulators will act abruptly, crafting a regulatory structure to fit the demands of a few early GS projects, without adequate understanding of the long-term implications of their rule-making. Such early regulatory action is often hard to amend and could affect the development of GS for decades. Care needs to be taken to ensure that the existing framework adequately addresses the novel risks arising from large-scale GS. Assessment of the existing regulatory environment for GS and debate about the structure of any new regulation are required, both to help guide the current technical research agenda and to enable informed regulatory decision-making.

Geologic sequestration is accomplished by injecting CO_2 at depths greater than ~1 km into porous sedimentary formations using drilling and injection technologies derived from the oil and gas industry. The technology required to inject large quantities of CO_2 into geological formations is well-established. Industrial experience with CO_2-enhanced oil recovery (EOR), disposal of CO_2-rich acid gas streams, natural gas storage, and underground disposal of other wastes allows confidence in predictions about the cost of CO_2 injection and suggests that the risks will be low. Once injected, evidence from natural CO_2 reservoirs and from numerical models suggests that CO_2 can—in principle—be confined in geological reservoirs for time scales well in excess of 1000 yr and that the risks of geological storage can be small.

Suitable formations for GS are found in deep sedimentary basins. Such basins frequently have sedimentary formations extending to a depth of greater than 2 km and are composed of horizontally stratified porous rocks with mean porosities often greater than 10%. The pore waters (generally very saline) and pressure are found (with some well-understood exceptions) near the hydrostatic pressure of a column of water extending to the surface, indicating that the formation waters are connected to the larger hydrosphere over long time scales.

At almost all plausible injection sites CO_2 will be less dense than the displaced brines, so buoyancy-driven flow will carry the CO_2 upward until it rests against the underside of low-permeability cap-rock. The buoyancy-driven flow makes any

* Corresponding author phone: (919)541-1949; fax: (919)541-7885; e-mail: Wilson.Elizabeth@epa.gov.

† Carnegie Mellon University.

‡ U.S. EPA National Risk Management Research Laboratory.

§ Present address: U.S. EPA National Risk Management Research Laboratory.

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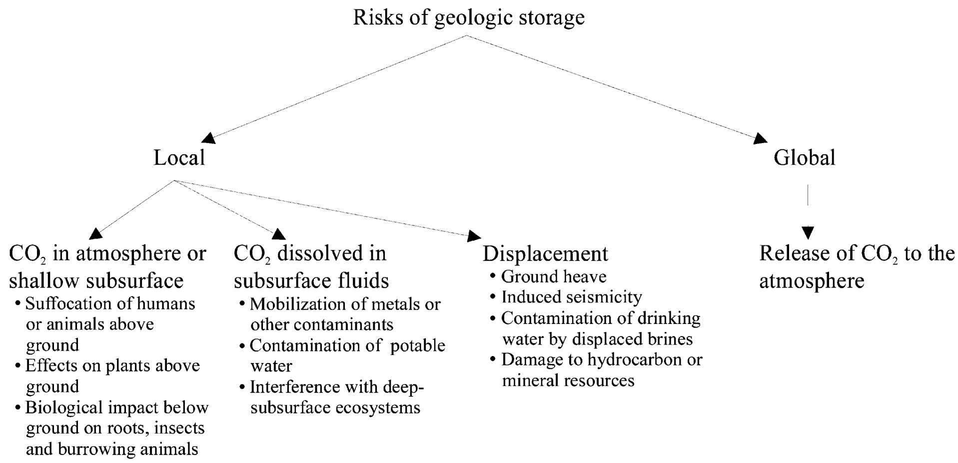

FIGURE 1. Taxonomy of risks of geologic sequestration. The risks fall in two categories: local environmental risks and global risk arising from leaks that return stored CO_2 to the atmosphere. The global risk may alternatively be viewed as uncertainty in the effectiveness of CO_2 containment. Local heath, safety, and environmental risks arise from three processes: the elevated CO_2 concentrations associated with the flux of CO_2 through the shallow subsurface to the atmosphere, the chemical effects of dissolved CO_2 in the subsurface, and the effects that arise from the displacement of fluids by the injected CO_2.

breach in the confining layer a pathway for upward migration and, depending on the configuration, can drive horizontal movement, making the areal extent of the CO_2 plume much larger than it would be for a neutraly buoyant fluid (*5*). Where CO_2 contacts the brines, it can dissolve into them, and the CO_2-rich brines are then negatively buoyant, greatly reducing the speed at which CO_2 migrates in the reservoir. The time scale for dissolution depends on the rate at which CO_2 migrates through undersaturated brine and thus on the configuration of the reservoir; typical dissolution time scales are of order 10^3-10^5 yr. Once CO_2 is dissolved, it may become further immobilized through geochemical reactions with the formation waters and the reservoir rock (*5*, *6*).

The risks of GS are categorized in Figure 1. Local risk associated with the surface release of CO_2 will be strongly dependent on the rate, volume, and surface topography (CO_2 is denser than air and can pool in pits or depressions). CO_2 causes significant physiological effect in humans at concentrations over 3% and will produce fatalities above 10% (*7*). The most obvious local risk is of catastrophic leaks such as well blowouts or pipeline ruptures. Catastrophic events may be caused by slow leaks if the CO_2 is temporarily confined in the near-surface environment and then suddenly released. At Lake Nyos (Cameroon), for example, lake waters that were gradually saturated with CO_2 from volcanic vents were suddenly vented, releasing ~100 kt of CO_2 that killed 1700 people (*8*). While the specific mechanism active at Lake Nyos can occur only in tropical lakes (because they do not turn over annually), mechanisms may exist that could confine slowly leaking CO_2 in the subsurface, enabling sudden releases. It is conceivable, for example, that CO_2 leaking from deep underground could infiltrate karst caverns at shallow depths and that such CO_2 could then be rapidly vented since it would no longer be confined in a porous media. Environmental effects of steady (noncatastrophic) surface venting of CO_2 have also been observed at Mammoth Mountain, CA, with extensive tree kills documented (*9*). Another class of risks arises from CO_2 dissolved in subsurface waters, which alters pH and could affect the stability of metal−organic complexes within the substrate (*10*). Finally, large volumes of any injected fluid impacts the subsurface environment by displacing the original material, sometimes causing local ground heave and inducing local seismic events.

The global risk stems from the re-release of CO_2 to the atmosphere. Because of energy penalties in CO_2 capture and sequestration, more CO_2 will be produced per unit of delivered energy using CCS/GS than would have been emitted if the fossil fuels had been used without sequestration. A leaky GS project can, therefore, increase emissions to the atmosphere per unit final energy delivered, although the emissions are delayed in time. If the CO_2 is retained for a century or longer, leaky GS can still have much of the economic value of perfect GS in mitigating climate change (*11*, *12*).

A robust and consistent framework for managing these risks will be required if GS is to play a significant role in mitigating CO_2 emissions. While local risks of GS can perhaps be managed within the existing regulatory framework, management of sequestered CO_2 leakage will likely require international agreement.

History of Underground Injection and Its Regulation

In the 1930s, petroleum technologies were adapted to inject oilfield-produced brine wastes underground to avoid surface water contamination (*13*). Produced brine waters had previously been pumped into evaporation pits or discharged to surface waters directly. Disposal of industrial waste by injection began in response to the strengthening of surface water pollution control regulations. The use of industrial injection wells pre-dates WWII; however, subsequent growth of such facilities was slow. Only four waste injection wells were in existence prior to 1950 (*14*). From an inventory in 1964 of 30 industrial wells, the number grew rapidly, with 110 in 1968, 246 in 1972, and 333 industrial and municipal wells in 1974, (figures not strictly comparable) (*15*).

Regulation of underground injection began with the states. As early as 1934, the Kansas Legislature gave the State Corporation Commission control over oilfield brine injection (*15*). Texas' Injection Well Act of 1961 was the first to specifically address other kinds of wastes, giving permitting power for oil field wastes to the Texas Railroad Commission, with injection of all other wastes requiring a permit from the Texas Board of Water Engineers (*15*). Throughout the late 1960s and early 1970s, state regulations of underground injection activities were adopted by Ohio, Michigan, West Virginia, New York, and Colorado. In 1971, Missouri became the first state to pass legislation forbidding underground disposal of wastes; North Carolina followed in 1973 (*15*).

Federal regulation of underground injection began in the 1970s in response to disposal well failures. In 1968 a Hammermill Paper Company (Erie, PA) well was thought to have contributed to contamination of groundwater 5 mi away (*16*). In the 1960s, the U.S. Geological Survey and the U.S.

TABLE 2. Summary of the Current UIC Program

well class, defined in 40 CFR 144.6	active wells (1999)	comments
I: deep injection of hazardous, municipal, other industrial wastes, deep radioactive	473[a]	nonhazardous, 266 wells, in 19 states
		FL municipal, 84 wells, ~0.5 Gt injected, in FL only
		hazardous, 123 wells, ~34 Mt injected handling 50% liquid hazardous wastes; [b] 10 000-yr no-migration demonstration required, in 10 states [majority in Texas (64), Louisiana (17), Michigan (9), Ohio (10), Indiana (4), Illinois (4)] avg depth ~1500 m
II: injection of fluids produced with natural gas storage or oil or gas production, EOR for oil and gas, storage of hydrocarbons liquid at STP	~154 000 in 32 states[b]	brine disposal, ~2.7 Gt injected[c]
		EOR with miscible CO_2, ~25 Mt injected in Permian Basin
III: wells injecting for mineral extraction	~30 000[b]	in situ solution mining of sulfur, uranium, metals, salt, etc.; active in 15 states
		80% of uranium and 50% salt used in U.S. comes from solution mining[a]
IV: hazardous or radioactive wastes injection within 0.25 mi of a USDW or injection into or above a USDW	40 sites for remedial cleanups, several hundred wells[d]	banned except for remediation
		prohibited under UIC[e] and RCRA
V: all other wells not included in classes I−IV	200 000[b] officially possibly as high as 685−500 000[d]	shallow disposal ponds, large capacity cesspools, drainage wells, recharge wells, subsidence control wells, experimental, geothermal energy, solution mining of conventional mines, etc.
		these occur in all states, no comprehensive inventory available

[a] Ref *36.* Other estimates differ: ref *16* estimates 532 class I active wells, 466 nonhazardous, and 126 hazardous with 84 municipal waste injection wells, similar to ref *37*. [b] Ref *16*. Active well numbers fluctuate greatly with 175 500 active in 1991 and about 148 000 active in 2000. [c] Estimate based on ref *37*; however, if the 1999 domestic oil production figure (5.88 million gal/d (*38*)) and estimate of 10 gal of brine for every gal of oil produced, the estimate is closer to 3.4 Gt/yr injected. [d] Ref *16*. [e] Class IV wells are prohibited by 40 CFR 144.13.

Army Corps of Engineers determined that a series of earthquakes near Denver was triggered by injection well disposal at the Rocky Mountain Arsenal, with one tremor measuring 5.5 on the Richter scale (*16*). In 1970 the Federal Water Quality Administration, one of the predecessors to the Environmental Protection Agency (EPA) adopted a policy that "opposed the disposal or storage of wastes by subsurface injection without strict controls and a clear demonstration that such wastes will not interfere with present or potential use of subsurface water supplies, contaminate interconnected surface waters or otherwise damage the environment" (*17*). The statement then declared that underground injection should be used "only until better methods of disposal are developed" (*17*).

In response to a directive in the 1972 Clean Water Act (CWA) for information on pollution control from "the disposal of pollutants in wells" (*15*), the EPA in 1973 also released a guidance document titled "Ground Water Pollution from Subsurface Excavations" that detailed control methods for underground injection. The EPA then tried to regulate under the CWA, but this proved impractical. The crux of this issue is whether the CWA provides protection for groundwater (*18*). The CWA adopts a broad use of the term "navigable waters", defining them as "waters of the United States", and sparking off much of the ensuing legal debate (*18*). In December 1973, the U.S. EPA's Office of the General Counsel issued an opinion that while the CWA issued permits for the "discharge of a pollutant", this was defined under the Commerce Clause to include only discharges into navigable waters (*19*).

Congress acted to extend the U.S. EPA's authority in 1974 with passage of the Safe Drinking Water Act (SDWA). SDWA gave the EPA administrator responsibility for developing regulations for state underground injection programs that provide minimum standards and ensure that injection activities do not harm underground sources of drinking water (USDW) (*15*). After being first proposed in 1976, the first set of Underground Injection and Control (UIC) regulations under SDWA were finally promulgated in 1980 (40 CFR 144−146) and established five distinct classes of injection wells. These minimum federal standards could either be adopted by state programs or implemented by the U.S. EPA directly. Some states have also been more restrictive, either imposing tougher standards or prohibiting injection activity altogether.

In the 1980 re-authorization of the SDWA, two specific provisions concerning the oil and gas industry were adopted. Constraints affecting class II (hydrocarbon-associated) wells were closely scrutinized by Congress as these were by far most numerous and, therefore, likely to bear the economic brunt of regulations (*20*). The first provision required that states need only regulate class II oil and gas associated injection wells in an "effective manner", while states were required to meet or exceed all federal standards to assume primacy for other well classes. In practice state regulation of class II wells is both more lax and more stringent than the federal standards. Second, the injection of natural gas for storage was exempted from regulation. The rationale was that natural gas injection does not harm groundwater and that any federal oversight might inhibit the needed expansion of gas storage.

Current Regulatory System

In the United States, with the exception of the outer continental shelf (see next section), underground fluid injection is managed under the UIC program, pipeline transport is regulated under the Department of Transportation, and most of the surface risks are handled by state EHS regulations.

The UIC regulations divide underground injection activities into five major classes. Table 2 summarizes the current number of wells in each class. Typically, class I wells are regulated by state departments of environment or natural resources, while class II hydrocarbon production wells are regulated by state conservation commissions or divisions of oil and gas. Currently, 33 states have been granted primacy. The EPA shares responsibility for UIC program implementation in 7 states, and EPA regional offices implement the UIC program for all well classes in 10 states and on all federal and Indian lands. Regional EPA offices also manage all class I hazardous no-migration petitions, the only well subclass that specifies a containment lifetime (*21*).

The explicit goal of the UIC program is to protect current and potential sources of public drinking water. The movement of injectate into an Underground Source of Drinking Water (USDW) is explicitly prohibited in class I–III wells, where a USDW is defined as an aquifer that has a total dissolved solids content of less than 10 000 mg/L (*13*). The rules mandate *zero* contamination: if "movement of any contaminant into the underground source of drinking water" is detected, corrective actions will be taken "as are necessary to prevent such movement" (40 CFR 144.12b).

While there are detailed requirements for siting, constructing, and monitoring injection well operation, there are no federal requirements for monitoring the actual movement of fluids within the injection zone, nor are there requirements for monitoring in overlying zones to detect leakage with the exception of specific class I hazardous wells, where this monitoring can be—but rarely is—specifically mandated.

GS under the Sea Floor

Off-shore GS is interesting for at least three reasons: (i) there will be smaller risks to humans and drinking water supplies if leaks occur; (ii) there may be less risk of leakage because one of the primary pathways for leakage in on-shore GS is thought to be the existence of many old abandoned wells, whereas there are fewer abandoned wells for off-shore reservoirs, and the abandonment methods are likely superior; and (iii) important offshore sequestration sites may exist near large coastal populations where opportunities for on-shore GS are limited. Moreover, it's noteworthy that the first large-scale GS project of any kind is located off-shore in the North Sea where ~1Mt of CO_2 is injected annually at Sleipner West (*4*). This section first covers domestic U.S. regulation before briefly reviewing relevant international treaties.

Submerged lands near the coasts are under state and UIC jurisdiction, so regulation and management are similar to the on-shore case described above. State mineral jurisdiction extends three nautical miles (5.6 km) from shore except in Western Florida and Texas, where it extends three marine leagues (16.7 km). We focus here on the seabed of the outer continental shelf (OCS)—extending from the limit of state jurisdiction to the 370 km (200 nautical miles) limit of U.S. exclusive economic zone jurisdiction. There has been considerably less sub-seafloor injection activity than on land, and the domestic regulatory history is much simpler. Regulation of GS under the sea floor is less clear-cut than that of on-shore injection since both domestic law and international treaties affect the legality of sub-seabed injection activity.

The OCS is managed by the Minerals Management Service (MMS) within the Department of Interior. Established in 1982, the MMS has primary responsibility for enforcing safety standards, specifying platform and drilling equipment requirements, inspecting offshore facilities, collecting and processing both environmental and production data, and managing revenue through site clearance and the abandonment of each lease. Within the bounds of relevant legislation and administrative law, approval of most routine mineral recovery activities in the OCS rests with the regional MMS administrators.

Underground injection occurs in the OCS. Sub-seabed injection and waste disposal in the OCS include the injection of water and produced natural gas to enhance oil recovery and the disposal of drilling cuttings, produced waters, naturally occurring radioactive materials above background levels, and other wastes associated with offshore oil and gas production. In the OCS, approximately 5.4 Mt of water was injected for EOR, and 0.9 Mt of water was injected for disposal in 2000, while 58.7 Bcf (~1.2 Mt) of gas was injected in the Gulf of Mexico and the Pacific Region, volumes that are minute in comparison with the on-shore injection operations shown in Figure 2. While seabed natural gas storage is not currently practiced, the MMS encourages gas injection as a routine part of oil and gas recovery operations (*22*). Re-injection of the natural gas that often accompanies oil production for pressure support—the second of these motivations—has become routine, with as much as 25% of gas re-injected in the Pacific region (*23*).

As is the case in the UIC program, the MMS regulations governing well abandonment address closure and site clearance but do not require monitoring of the closure integrity (see ref *24*). Likewise, the regulation of CO_2 injection in the OCS depends on the source of the CO_2 and the purpose of injection. The use of CO_2 for EOR is allowed under current administrative law. Disposal of CO_2 from sources and for purposes unrelated to OCS oil and gas operations, in contrast, is not covered under the existing regulatory regime and would most likely require an extension of MMS authority (*25*). Domestic legislation and administrative laws, therefore, provide an indefinite answer to questions about the legal status of OCS sequestration.

Several international agreements either address protection of the ocean environment specifically or, in regulating the transboundary movement of pollutants, limit ocean waste disposal. Of these, the 1972 London Convention (which the United States has ratified into law and is known more formally as the Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter)—especially in its more recent guise as the1996 London Protocol (which the United States has not ratified)—is the most definite. And as the London Convention is also one of the few international treaties relevant to sub-seabed CO_2 sequestration to have entered U.S. law, it is especially important. Negotiated in 1972 and in force since 1975, the London Convention originally sought to prevent marine pollution by limiting the discharge—or "dumping"—of human-generated materials into the oceans. Subsequent amendments banned ocean disposal of industrial and radioactive wastes as well as offshore waste incineration. These amendments were brought together in a more comprehensive—and restrictive—revision as the 1996 Protocol. Though the 1996 Protocol is not in force, it will replace the earlier 1972 Convention when it receives the requisite number of state signatures. In addition, the 1996 Protocol requires that a "precautionary approach" be taken when the discharge of a given substance may result in environmental damage.

Neither the London Convention's classification of banned substances nor the 1996 Protocol's list of allowed materials include CO_2. The "wastes or other matter" which both seek to regulate refer to "material[s] and substance[s] of any kind, form or description." A more specific distinction, however, rests on the definition of "industrial waste". By amendment, the 1972 Convention bans the discharge of such matter, defined as "waste materials generated by manufacturing or processing operations". In addition, the 1996 Protocol prohibits the discharge of wastes producing a biological response in marine life above an acute (or chronic) threshold, and in all cases where "adequate information is not available to determine the likely effects of [a] proposed disposal

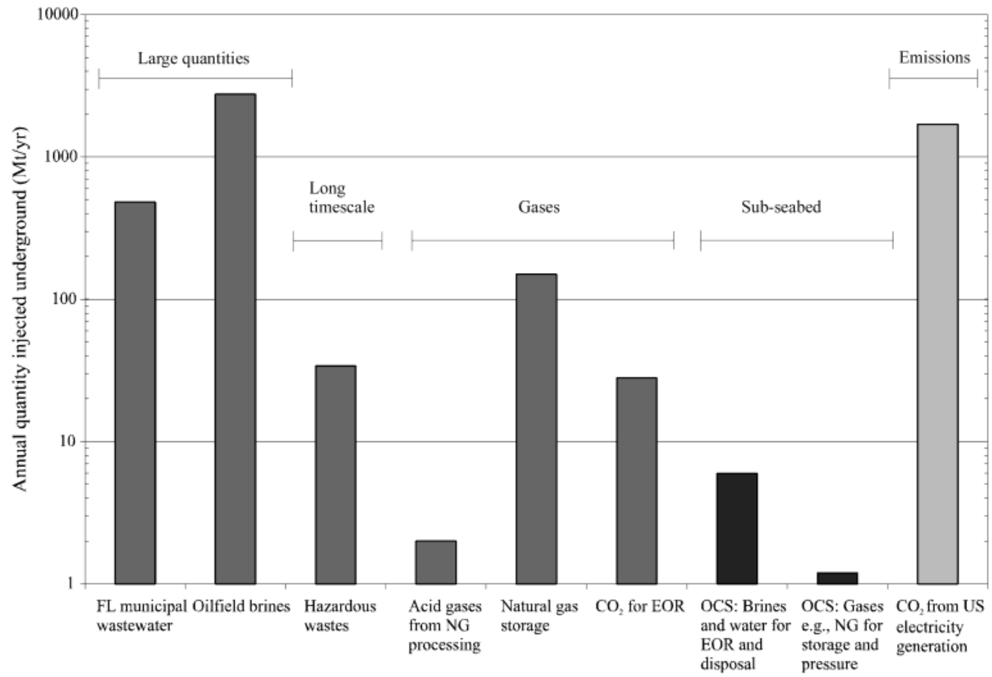

FIGURE 2. Annual underground injection activity estimates and CO_2 emitted (Mt/year) log scale (*30*, *37*, *39*–*45*). Any GS program will need to manage and inject large quantities of gases and store them underground for long time periods. Large quantities of produced brines are injected underground with oil and gas production, and Florida manages large quantities of municipal wastewater through underground injection. Gases are managed within acid gas injection, natural gas storage, and CO_2 injected for EOR. Only class I hazardous waste wells specify any containment time underground. OCS injection and CO_2 produced from electricity generation are shown for comparison.

option". CO_2 would currently appear to meet these restrictions.

Parties to the convention have debated the status of CO_2. According to the Convention's Scientific Group, CO_2 resulting from the use of fossil fuels is an industrial waste, and its disposal into the oceans (including the sub-seabed) would therefore violate the London Convention (*26*). Participants at a subsequent Consultative Meeting questioned this interpretation, however, and requested that the Scientific Group monitor proposals for ocean disposal of CO_2 pending further discussion (*27*). Hence, the legality of ocean GS under the London Convention remains unresolved.

Further speculation about the legal status of sub-seabed GS, however, must consider other aspects such as the status of submerged lands under the London Convention. Whereas the 1972 Convention defines "sea" as "all marine waters other than the internal waters of States", the 1996 Protocol extends this definition by explicitly including "the seabed and the subsoil thereof". Furthermore, the 1996 Protocol considers "any storage of wastes or other matter in the seabed and the subsoil thereof from vessels, aircraft, platforms or other man-made structures at sea" as dumping. In addition, while the 1972 and 1996 agreements allow disposal of wastes resulting from "the normal operations of vessels, aircraft, platforms or other man-made structures at sea and their equipment", such discharges are illegal when the vessels or structures exist solely for disposal or when the waste itself is a byproduct of the offshore treatment of other wastes. Both agreements, however, specifically exclude "[t]he disposal or storage of wastes or other matter directly arising from, or related to the exploration, exploitation and associated off-shore processing of seabed mineral resources".

Public dispute about sub-sea GS has begun. Greenpeace has formally stated their opposition to what they term "ocean disposal", encompassing both sub-sea floor GS as well as ocean disposal of CO_2 (*28*). At Sleipner West, they question not only the legality of subsea injection under the London Convention, but also the long-term safety and surety of containment of the injected CO_2.

The 1996 London Protocol, however, is not in force. Absent a ruling that anthropogenic CO_2 is "industrial waste", it is therefore uncertain whether offshore sequestration is currently banned. Pending this decision or until the United States becomes a signatory of the more limiting 1996 Protocol, it appears that CO_2 sequestration in submerged lands beneath the waters of the Gulf of Mexico would not be prohibited as "ocean dumping" under the 1972 London Convention.

Underground Injection: Current Practice and GS Analogues

Experience with underground injection will shape the regulatory environment for GS and offers specific analogues that can inform assessments of the risks. This section examines three important injection activities chosen as analogues for specific aspects of GS: Florida municipal wastewater injection (large quantities), hazardous waste injection (long storage times mandated), and CO_2-EOR (experience with CO_2).

As demonstrated in Figure 2, current injection activities encompass injection volumes similar to what would be required for large-scale GS. Florida, for example, disposes of ~0.5 Gt/year of municipal wastewater via deep injection. The largest injection wells are 0.75 m diameter, and injection rates exceed 70 kt/day (*16*). Wastewater is injected into the extremely permeable Floridan formation (known as the boulder zone) at a flux-weighted average injection depth of 945 m (*29*).

These activities offer some lessons for GS. First, because the displacement-related risks (Figure 1) are roughly independent of the kind of fluid injected, the large volumes currently injected (Figure 2) provide a strong basis for assessing the displacement-related risks of GS and suggest that these risks may be small. Second, municipal wastewater, like CO_2, is less dense than the waters of the receiving formation and so is subject to buoyancy-driven upward flow. The analogy to CO_2 is imperfect as density differences are smaller and are likely to dissipate more quickly because wastewater is fully miscible. Injected wastewater has been found in monitoring wells of USDW's above the injection zone at three sites thus far, indicating injected waters have migrated from the injection zone (*30*). Although the environmental impacts of this leakage are likely small, the fact that the UIC rules allow no leakage has produced a serious problem for environmental regulators. The U.S. EPA is currently proposing to amend the UIC regulations in this case to permit leakage if it does not endanger USDWs, an action that has been challenged by environmental groups (*31*). Similar problems might arise if GS was managed under current UIC regulations.

Containment time of injected CO_2 is another key consideration. UIC regulations do not, with the exception of hazardous waste wells, specify any containment time for the injected wastes, whereas the Class I Hazardous Program requires that injected wastes remain in the receiving formation for >10 000 yr. The siting, construction, monitoring, and reporting requirements for this injection activity are by far the strictest of any well class. While the Class I Hazardous Program may be run through the state, operators of hazardous waste wells must receive approval of a "no-migration demonstration", required by the Resource and Conservation Recovery Act and granted through the regional EPA office in addition to their state or U.S. EPA injection permit (*13, 32*). The no-migration petition requires operators to demonstrate using computational models that wastes will not migrate from the injection zone for at least 10 000 yr or be will rendered harmless (through chemical transformation modeling). While there have been few reported problems, it is difficult to assess the success of the program because there is little monitoring designed to assess the transport of injected fluids, and there are, therefore, no studies comparing the fluid transport predictions made in the no-migration petitions with observations. It is interesting that current efforts, such as those at Sleipner West and Weyburn, to study the transport of injected CO_2 for GS are already more advanced than any comparable studies of fluids currently disposed of underground.

While no carbon dioxide is currently being injected for GS in the United States, roughly 30 Mt of CO_2/yr is injected for EOR, far more than elsewhere in the world. Industrial experience with EOR provides a practical basis for estimating the costs and risks of GS and demonstrates industry experience with CO_2 regulation under the UIC program. Most CO_2 for EOR is currently supplied by natural reservoirs and is transported to injection sites by pipelines as long as 800 km. In addition to natural sources, several gas processing plants, a fertilizer plant, and a coal gasification plant (injecting in Weyburn) all capture anthropogenic CO_2 and inject it for EOR (~5 Mt/yr internationally) (*33*).

Current EOR operations must pay for CO_2 (~15 \$/t of CO_2), so they are designed to maximize the ratio of CO_2 consumption to oil production. If there was a value for sequestered CO_2—resulting from a carbon tax or equivalent regulatory constraint—then operators would change their practice to co-optimize oil production and CO_2 sequestration, greatly lowering the cost of GS in comparison to injection into saline aquifers where there is no byproduct. The value of CO_2 for in enhancing oil recovery provides a low-cost niche for CCS/GS.

While EOR projects demonstrate that tens of Mt/yr of CO_2 can be safely injected underground, without new research the existing projects yield little data about crucial questions such as the rate of leakage through cap-rocks and artificial penetrations, the migration of CO_2 in reservoirs, and the rate at which CO_2 dissolves in brine-filled reservoirs or reacts with minerals in the reservoir rock.

Discussion

The United States has considerable experience injecting fluids underground—both on land and under the sea floor—for purposes of storage, recovery, and disposal. An extensive regulatory framework has evolved to ensure that the impact of injection activities is minimized. More extensive regulations exist on land than off-shore, and injection experience is greatest in regions of the country with historic oil and gas production or heavy industrial activity.

The current regulatory structure for underground injection cobbles together many different agencies and regulatory authorities. Many different federal and state regulations and actors are charged with ensuring that materials are handled, transported, and injected in a safe and appropriate manner. Pipeline transport is regulated by the Department of Transportation, for instance, while most of the EHS regulations are set by OSHA and adopted and enforced by the states. Underground injection activities on land and in state waters are regulated by the Environmental Protection Agency, with primacy given to different state agencies. Permitting requirements vary by individual well class. Injection in the OCS is permitted and managed by the Minerals Management Service.

Even within the same jurisdiction, the injection of identical fluids is treated differently, depending on their source. Produced brine from a hydrocarbon production operation and that from an industrial process fall under different well classes; are managed by different institutions; and are subject to different site characterization, construction, management, and reporting requirements. Under current rules, the regulation of GS could easily fall under different regulatory jurisdictions and be subjected to quite different requirements depending on the source of the CO_2.

The inconsistencies in treatment of underground injection for similar fluids means that, even assuming a consensus on the appropriate regime for regulating GS, it would be difficult to subsume that regime in the current regulatory structure. It is unclear now if CO_2-specific regulations would be integrated within the existing underground injection regulations or if, in the long run, an entirely different regulatory approach would be beneficial.

The difficulty in building a system for regulating CO_2 storage is not simply due to the technical uncertainty in predicting the lifetime of CO_2 in reservoirs, rather it arises from uncertainty about the political and regulatory goals of GS. Should the median lifetime of sequestered CO_2 be 500 yr or 10 000? What fraction of early failures are we willing to accept? A rough consensus on these issues will be needed to drive the GS research agenda, determine the appropriateness of individual technologies, and shape regulatory structures for the future.

While uncertainty in predicting the fate of CO_2 in reservoirs can be reduced through research and experience, it cannot be eliminated. Some leaks are inevitable if GS is employed on a large scale. The challenge is to build a regulatory regime that works despite these uncertainties. Efforts to design technology for injection and monitoring of CO_2 and to craft a system to regulate these activities cannot succeed until there is some common understanding about these programmatic goals.

In most cases, injected CO_2 will be less dense than the formation waters. Most fluids injected underground thus far have been denser than the formation waters. While buoyant fluids have been injected in large quantities (see, for example, Floridian wastewater and natural gas storage in Figure 2), containment has proven more difficult, and some movement has been documented (*30, 34*). The strong positive buoyancy of CO_2 combined with the long time scales that will required for sequestration will pose a significant management challenge within the current regulatory framework.

Aside from prescribed well integrity tests, the current regulatory structure for underground injection is almost exclusively procedural rather than performance-based. That is, the regulations specify what an operator must do; for example, they specify how an injection well must be constructed rather than specifying an outcome, such as a maximum acceptable leak rate, that must be achieved. Under a performance-based system, in contrast, the operators are directly responsible for achieving the desired outcome and must convince the regulator of their ability to achieve these performance standards. While performance-based regulations may offer important advantages such as increased economic efficiency and greater flexibility, there are several drawbacks to their use in managing GS. Performance-based regulations ultimately hang on our ability to infer performance from quantities that can be directly measured. For GS, however, a performance-based approach would have to specify quantities, such as the maximum rate of leakage over the next century that cannot—even in principle—be directly measured but must instead be inferred from models or potentially costly monitoring schemes.

Although it is problematic, performance-based regulation has been used in cases where performance must be inferred from models. As described above, the regulation of hazardous waste injection currently uses a performance-based approach, as does the current framework for the geologic storage of radioactive nuclear wastes (*35*). A performance-based system provides a framework in which the allowable leak rate would be limited, but nonzero, over a specified time frame as it is for radioactive waste. It seems likely that a regulatory regime must accept limited leakage if GS is ever to play a significant role though this could make achieving a regulatory consensus more difficult.

Procedural and performance-based approaches to regulation are not as divergent as they might first seem; both must have a performance goal. For performance-based standards, the goal is explicitly defined and operationalized through defined monitoring and verification activities to ensure that acceptable risk levels are not surpassed. In procedural regulations, the goal is implicit. Such regulations are—or ought to be—crafted to ensure that systems permitted under the procedural rules ultimately meet the implicit performance goal. At present there is no consensus on the appropriate sequestration lifetime, a crucial element of the performance goal.

Technological capability is a necessary but insufficient condition for GS to play a major role in mitigating CO_2 emissions. To fulfill its promise, GS must evolve from a collection of individual technologies into a large-scale technological system for managing fossil-fuel carbon. To be successful, such a technological system must comprise a suite of technologies linked by a network of institutions, financial systems, and regulations that are accepted by industry and are able to achieve broad public understanding and acceptance.

What form those regulations assume, what entities are involved in project approval and ongoing oversight, how cooperative or adversarial the regulatory process is, and how many opportunities are presented for litigation and other third party interventions will together be critically important in determining the economic attractiveness and social acceptability of GS. Research, development, and deployment are now outpacing the development of a framework for managing GS. There is an urgent need to address the risks and to begin crafting an appropriate regulatory environment for GS.

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