The Impact of Liability on the Adoption and Diffusion of Carbon Capture and Sequestration Technologies

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Introduction

Carbon capture and sequestration ("CCS") technologies are a leading option for significantly reducing CO_2 emissions from human activities. The interest in CCS stems from the prominence of global climate change on the international environmental agenda and the expectation that fossil fuels, the leading source of CO_2 emissions, will remain the dominant source of energy supply well into the twenty-first century. CCS involves capturing the CO_2 arising from fossil fuel combustion, transporting the CO_2, and injecting the CO_2 into a sequestration site where it will remain for a very long time (IPCC 2005). Although there are a number of potential sequestration sites, geological formations, including saline aquifers and depleted oil and gas fields, have the most promise because of analogous experience. The injection of CO_2 into geological formations is known as geological sequestration ("GS") and is the focus of this paper.

If CCS is to make a significant impact in reducing CO_2 emissions, large-scale deployment will be necessary. Although the technical and economic barriers to CCS have been well documented (IPCC 2005), relatively less attention has been paid to the impact of liability on the adoption and diffusion of CCS technologies. Liability is a crucial issue because of the potential for CO_2 to escape from the subsurface formation. As a result of FutureGen, the $1 billion public-private partnership to build a zero-emissions power plant using CCS, there has been some legislative and regulatory activity concerning the CCS liability issue, as shown in Table 1. While these proposals attempt

to assign responsibility to injected CO_2 ownership or indemnification of CCS operators, the question of how liability will be managed in the long-term remains unanswered.

Table 1 CCS Liability Proposals

PROPOSAL	SUMMARY
FutureGen Final Request for Proposals (March 7, 2006)	"The offeror agrees to take title to the injected CO_2 and indemnify the FutureGen Industrial Alliance and its members from any potential liability associated with the CO_2"
Texas House Bill 149 (May 15, 2006)	Texas Railroad Commission "shall acquire title to CO_2 captured" by a FutureGen project
[Failed] Costello Amendment to HR 5656 (June 27, 2006)	U.S. Department of Energy indemnifies FutureGen consortium and companies for "any legal liability arising out of, or resulting from, the storage, or unintentional release, of sequestered emissions," up to $500 million per incident

The premise of this paper is that jurisdictional differences in liability will play an important role in the diffusion of CCS technologies. We consider the subsurface injection law of two jurisdictions: California and Texas. California is widely considered to be a first mover in environmental initiatives and climate change regulation. Its Global Warming Solutions Act of 2006 (Assembly Bill 32) implements a greenhouse gas emissions cap for the electric power sector. Texas has extensive experience with subsurface injection and hydrocarbon recovery. Oil producers in the state have expressed an interest in tying CCS with their tertiary recovery (also known as "enhanced oil recovery") activities, where CO_2 is injected into oil fields to enhance the recovery of oil. In addition, Texas has a rich jurisprudence in subsurface injection liability issues.

This paper serves two purposes. First, we link potential CCS system requirements with potential risks and damages. We examine a number of potential CCS system requirements, including site characterization, operations, and post-closure. Second, we examine how damages are treated in the subsurface injection realm, with particular

attention paid to distinctions in Texas and California regulations and case law. We focus on both subsurface injection into oil fields, where there is significant case law, and injection into saline aquifers, which has less case law than injection into oil fields, but where there is significant operational experience with respect to natural gas storage.

This paper has several caveats. First, we do not address the contractual liability associated with breach of an agreement under a carbon-constraining regime. Second, our focus is on local damages from CCS, not global damages from CO_2 leakage with respect to climate change. Third, although co-injection with other gases, such as hydrogen sulfide, may be important from a cost standpoint because of the potentially high cost of capturing a pure stream of CO_2, our paper restricts its analysis to the injection of only CO_2. Finally, our analysis focuses on the U.S. liability regime, although it has broader implications for countries that follow similar precedent.

Carbon Capture and Sequestration: Technology and Risks

Any future liability from CCS is tied to the potential risks of the technology. While the IPCC Special Report on Carbon Capture and Storage estimates that over 99% of injected CO_2 is "very likely" to remain sequestered for upwards of 1,000 years in a properly selected site (IPCC, 2005), regulatory and legal frameworks for managing risk over a much shorter time frame. The quantities of CO_2 to be injected are large; a one GWe capacity coal-fired power plant generates approximately 30,000 tons of CO_2 per day, and over the plant's 30 year lifetime, injected CO_2 could increase formation pressures over an area of more than 100 km^2, assuming a 100 m thick injection zone.

CO_2 will be injected as a supercritical fluid (having properties of both a liquid and a gas) at depths below roughly 1 kilometer. The injected CO_2 will be less dense than the formation waters, and have a tendency to migrate upwards and laterally within the formation. Thus it is important that the sequestration formation have an overlying low permeability caprock that will impede upward migration of the CO_2. There are a number of monitoring tools for identifying the integrity of the subsurface formation. The best

practice approach is to use 3D seismic monitoring, where sound waves are directed at a subsurface location and the resulting sound wave reflections are recorded. Sensors are maintained in three wells, allowing for a three-dimensional profile of the subsurface. Such geophysical mapping allows for visualization of surface stratigraphy, faulting patterns and trapping mechanisms, but is less effective for identification of narrow vertical intrusions like abandoned wells.

However, over large areas, geologic uncertainty is great, and the effect of crustal heterogeneity on the integrity of the sequestration site is largely unknown. Any risk analysis must be grounded in local geology, which will factor into local regulatory and liability considerations. The risk profile and subsequent analysis will vary significantly across sedimentary basins, reservoir classes and compositions, structural configurations, and well densities and completion histories.

While unlikely to occur in a properly characterized site, leakage from the injection zone could potentially result in damage to hydrocarbon or groundwater resources, or merely invasion of property rights due to trespass. Additionally, leakage to the surface or near-surface could potentially endanger ecological or human health. A schematic of risks is shown in Figure 1.

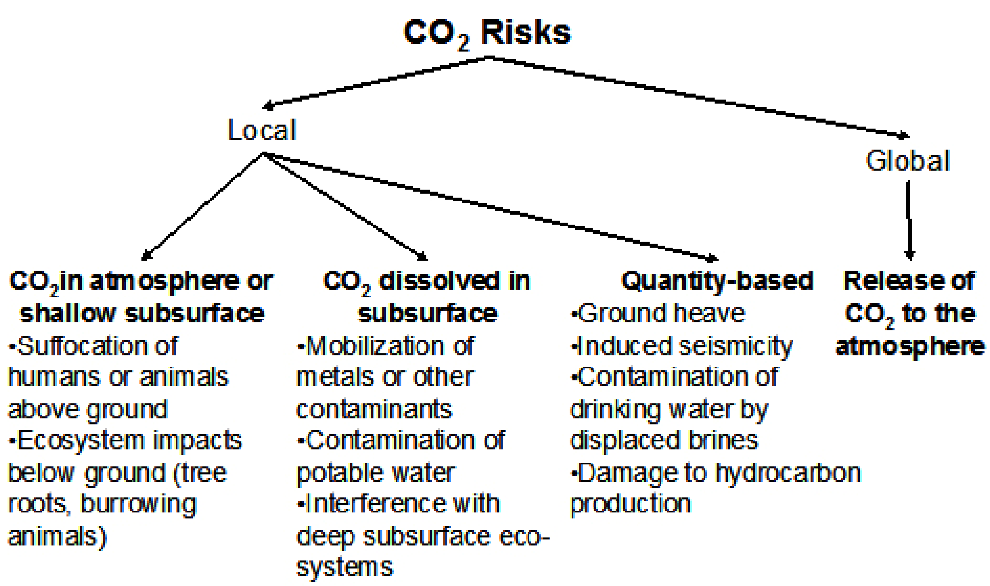
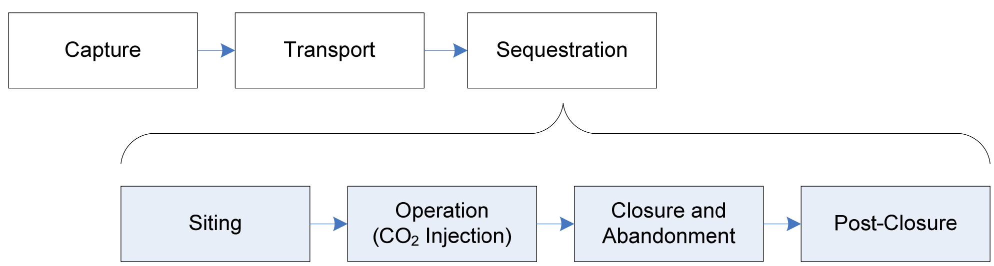


Figure 1: Typology of different risk from geologic carbon sequestration (Wilson, Johnson et al. 2003).

Risks to subsurface or surface resources change over time, with overall sequestration risk decreasing as the sequestration site becomes more secure with increased dissolution of the CO_2 in formation waters (over hundreds of years), and mineralization of CO_2 (over thousands of years).

Carbon Capture and Sequestration Project Lifecycle and Liability

The lifecycle of a CCS project undergoes four distinct phases, each with unique risks, liabilities, and management strategies. Broadly, the life-cycle of a CCS project can be broken into a) siting, b) operation (injection of CO_2), c) closure and abandonment, d) long-term post-closure care. Figure 2 outlines project phases, potential activities, associated liability and responsible parties.



Issue	Large/legal reservoirs; geophysical trespass	Leakage to surface; groundwater, minerals; seismicity; trespass	Leakage to surface; groundwater, minerals; seismicity; trespass	Leakage to surface; groundwater, minerals; seismicity; trespass
Who sets the rules?	Legislature; courts	EPA/UIC; OSHA; state regulator	EPA/UIC; state regulator	Legislature/Congress; EPA; courts
Potential tortfeasors?	Developer	Operator	Operator	Operator; long-term responsible entity
Potential victims?	Surface, mineral owners	Surface, mineral, groundwater owners; workers	Surface, mineral owners	Surface, mineral owners; public; env't

Figure 2: Liability of Geologic Sequestration According to Project Phase

As responsible parties shift according to project development, it is helpful to examine potential legal requirements and liabilities throughout different stages of the project life-cycle. Considerations for the siting, operational and closure/post-closure phases are discussed here.

Siting: Establishing large and legal sites to inject CO_2

The establishment of large-scale sequestration reservoirs and definition of the associated property rights and liability arrangements are critical for the deployment of GS. Large volumes must be injected to achieve individual to fulfill overall greenhouse gas stabilization objectives, and individual projects are likely to manage millions of tons of CO_2 annually, as discussed in the risk section. In 2005, U.S. electricity production emitted roughly 2.5 billion tons of $CO_{2,}$ (EIA, 2006). If CCS were employed to cut North American CO_2 emissions by even 10%, hundreds of individual plants and facilities would need to capture and sequester CO_2. Even if injecting into a stacked formation, the areal extent of the subsurface sequestration pool is likely to be extensive and intersect with pre-existing mineral rights, water rights, and surface estate owner claims. These physical system attributes intersect directly with pre-existing of subsurface ownership and liability regimes. For example, an initial analysis of a potential FutureGen site in rural Illinois found that the modeled subsurface injection pool intersected 69 individual parcels (Striecker, 2006).

Proper site characterization is important for mitigating liability for subsurface trespass. Subsurface trespass has been the focus of most of the case law on subsurface injection liability. If the sequestration operator has not characterized the geological formation adequately, the CO_2 could potentially migrate into adjoining areas of the subsurface where property rights have not been acquired (Wilson & de Figueiredo 2006). In a subsurface trespass cause of action, the plaintiff would need to show the intentional and unauthorized entry of the defendant's sequestered CO_2 and that the plaintiff was harmed, such as by the lost use of the subsurface space (Ragsdale 1993). Courts have generally been "cautious in finding liability for injected fluid subsurface entries" (Ragsdale 1993). Our analysis of the relevant case law shows that Texas has significant experience in

analyzing the subsurface trespass issue, but no cases directly on the subsurface trespass issue in California. Despite the multiple decades of experience with injecting CO_2, there have been no cases related to subsurface trespass from CO_2 injection in either Texas or California.

Proper Characterization: Difficulties

Owners of existing subsurface property interests could impede proper site characterization. Subsurface injection analogs to CCS, such as secondary oil recovery and natural gas storage, have required the use of large areas of the subsurface. Projects have been able to be deployed through the use of unitization, in the case of secondary oil recovery, and federal and state eminent domain, in the case of natural gas storage. Under current law, site characterization of a CCS site in areas without unitization would require contracting with each surface and subsurface estate owner for permission to survey the area, otherwise the operator will risk liability on the basis of trespass.

There are two types of trespass issues relevant to GS: geophysical surface trespass and geophysical subsurface trespass. Geophysical surface trespass takes place when a trespassing party uses the surface to conduct seismic and other surface or near-surface geophysical operations (Anderson, 2004). For GS, this implicates the use of geophysical operations to determine the suitability of a geological formation. Liability may depend on physical entry upon the property. Geophysical subsurface trespass implicates trespass caused by the underground intrusion of CO_2. Liability derives from CO_2 migrating into lands where property interests have not been acquired. For secondary recovery operations, this has been addressed through the use of unitization.

There is an inherent tension between individual and collective rights when unitizing hydrocarbon production fields or establishing a natural gas storage site. Creating a field unit for secondary oil recovery may take months, or even years, of negotiating to secure all necessary rights and reach an agreement, as understanding the shares of risk and production from operations is complicated. Mineral estate owners are free to engage in voluntary unitization. Most producing states also have a “compulsory joinder of interest,” where a unit is created after a certain percentage of owners of the pool has

agreed to unitization (50-85%) (OTA, 1978). Unitization is more difficult in states without compulsory joinder because of the liability associated with potential resource damage of conjoiners.

Statutes in California and Texas have not been particularly effective with respect to unitization. In spite of its importance for U.S. oil and gas production, Texas does not have a compulsory unitization statute, making the establishment of large fields particularly difficult. In California, 65-75% of royalty interest owners must agree for a field to be unitized, but only where the California Subsidence statute or the California Townsite statute applies. The former only affects areas where subsidence is severe and the latter is only applicable where 75% of the oil production fields lie within an incorporated area (OTA, 1978). However, the existence of a compulsory unitization statute may affect the ability of private parties to negotiate their interests (Libecap and Smith 2003).

Natural gas storage fields are created in an analogous way to compulsory unitization. State and federal legislation authorizes the use of eminent domain to support the establishment of natural gas storage fields. The natural gas storage companies (public or private) traditionally lease rights to the strata relevant for storage from interest holders (surface, mineral, and sometimes lease holders). If storage is threatened by any land not legally included in the storage area, the land can be condemned using the state or federal powers of eminent domain and a showing that a beneficial public use arises from a natural gas storage facility. Under the Fifth Amendment of the U.S. Constitution, "…nor shall private property be taken for public use, without just compensation". It will be interesting, given the current climate on eminent domain in a post-Kelo v. New London world, 545 U.S. 469 (2005), to see if the upcoming ballot initiatives in twelve states restricting eminent domain activities will influence the ability to establish eminent domain statutes for GS projects (see Yardley, 2006).

There are significant legal barriers in creating large-scale GS projects. Unitization and eminent domain have been used in analogous subsurface injection contexts to establish large subsurface reservoirs and to resolve issues such as multi-party injection into the

same reservoir and conjoiner rights and liabilities. However, analogous legislation has not been established in the GS context. Because of the scale of GS projects and potential lack of material benefit to many of the interest holders, employing the powers of eminent domain might be necessary for establishing reservoirs of an appropriate size. Such rights could be established by a state legislature. Model language for resolving property rights issues has been proposed by the Interstate Oil and Gas Compact Commission's Geologic Sequestration Task Force's Regulatory Framework for Carbon Capture and Geologic Storage (Bliss, 2005).

Interestingly, injection of waste under the auspices of the EPA's Underground Injection Control Program (which would also presumably regulate CO_2 injection) has not required similar contracting or negotiations for disposal rights, even thought the scale of some of the projects has been quite extensive. In the limited instances of case law focused upon hazardous waste injection and municipal waste water disposal, no damages to surface owner interest were found.

Operation: Liability from environmental risk, damage to hydrocarbons and harm to groundwater

The operational phase of a GS project involves injecting the captured CO_2 deep underground. While site operation is managed to prevent escape from the confining interval, CO_2 migration to the surface would implicate existing liability frameworks. Additionally, damage to hydrocarbons or groundwater (either directly or through displacement) is potentially actionable. Bounding both the probability of the potential risk and the damage will help to manage any potential impact.

Leakage to the surface

Tort liability for toxicological and environmental risks due to CO_2 leakage is an obvious GS liability concern. CO_2 is an asphyxiant, respiratory stimulant, and both a stimulant and depressant of the central nervous system (OSHA, 1978). Elevated concentrations of CO_2 can lead to adverse consequences to humans, including death (Benson, 2002). The toxicological effects of CO_2 will depend on the concentration and duration of exposure.

The potential of slow releases to the surface raise concerns of environmental degradation. Although CO_2 in moderate amounts (500-800 ppm) over atmospheric background (370 ppm) can be beneficial to plant life, it can become harmful at higher concentrations (Benson, 2002). The range and effects of high levels of CO_2 on plants has not been clearly delineated, but an often cited example of high concentrations of CO_2 being detrimental to plant life is the case of Mammoth Mountain, a young volcano in the eastern Sierra Nevada of California. The U.S. Forest Service found 100 acres of dead and dying trees on the mountain, the most likely cause being that CO, derived from magma beneath the volcano had been seeping through the ground and increasing concentrations of CO_2 in the soil, intruded through a fault in the subsurface, and allowed the CO_2 to leak upward towards Mammoth Mountain (USGS, 1996).

Harm to person or property would rely upon established theories of nuisance and negligence. However, challenges in proving a causal relationship between the GS project and actual harm could be expected to change over time as relationships between the injection of CO_2 and resulting damage are better established or viewed as inconsequential. Additionally, leakage to the surface could potentially damage public or environmental health. While the probability of this risk is low, there is precedent in the natural gas storage context for establishing liability for toxicological risks. For environmental risks, there are protocols for evaluating damage to cropland or forestry. Liability may depend on the permanence of damages and the ability to establish a causal link between the damage and injected CO_2. However, there is less jurisprudence establishing methods for the damage of non-economic lands or aquatic areas.

Groundwater contamination

Groundwater contamination due to CO_2 leakage will likely be regulated by the EPA Underground Injection Control Program, established under the Safe Drinking Water Act of 1974 to assure that any underground injection activities will not endanger drinking water sources. Underground injection of fluids must be authorized by permit or rule, and certain types of injection are prohibited because they may present an imminent and substantial danger to public health. States may elect to take “primacy” over their

injection wells, i.e. regulate underground injection within their borders using the EPA standards as a minimum basis. The EPA has established five classes of injection wells, with applicability depending on the purpose of injection, depth of injection, and nature of the injectate. The EPA recently released guidance that experimental CO_2 projects should be regulated under its Class V category, which has been used in the past for experimental injection wells and stated that any commercial projects would require additional scrutiny (US EPA 2006).

Damage to groundwater resources is another important liability consideration for future CCS projects. Groundwater law governed by an entirely different set of regulations and norms than mineral law, and substantive law may differ significantly from state to state. In California, all groundwater is the property of the state, with use rights granted from overlying, prescriptive or historic pueblo rights. Surface and groundwater use is coordinated and permitted by State Water Resources Control Boards and Regional Water Quality Control Boards with regulations set forth in the California Water Code. Water pollution in California may be considered a "nuisance," which is defined under state law as water that "(1) [i]s injurious to health, or is indecent or offensive to the senses, or an obstruction to the free use of property, so as to interfere with the comfortable enjoyment of life or property, (2) [a]ffects at the same time an entire community or neighborhood, or any considerable number of persons, although the extent of the annoyance or damage inflicted upon individuals may be unequal, [and] (3) [o]ccurs during, or as a result of, the treatment or disposal of wastes." (California Water Code, §13050(m)). Private parties and government agencies can file a cause of action for relief from contamination. Regional Water Boards can require polluters to take remedial action or pay for disrupted water service. Regional Water Boards can also issue civil fines, not to exceed $5,000 each day or $10 per gallon. If the civil liability is imposed by the courts, fines may not exceed $15,000 per day of the violation or $20 per gallon of discharged waste (California Water Code, §13350(e)).

In Texas, the "rule of capture" historically allowed landowners to use any groundwater accessible from their land, but this right has been truncated by the Texas Water Code. The Code establishes groundwater conservation districts and provides for "the

conservation, preservation, protection, recharging, and prevention of waste of groundwater, and of groundwater reservoirs" (Texas Water Code 36.0015). Additionally, the Texas Groundwater Protection Committee serves as an inter-agency body to coordinate the regulation of groundwater by multiple state agencies (Texas Water Code 26.403). The Texas Department of Agriculture, the Texas Railroad Commission, and the State Soil and Water Conservation Board all have regulatory responsibilities for groundwater.

Given the evidentiary demands for proof of environmental harm, some of the causal chains of CO_2 damage may be too attenuated. For example, metals mobilization (*in situ* CO_2 altering the pH of subsurface water which could change the metal or organics composition of potable water) or groundwater displacement (large volumes of CO_2 forcing more saline waters into fresh water formations and displacing the *in situ* fresh water) may be difficult to prove in a court of law.

Hydrocarbon Damage

Inadvertent damage to hydrocarbon resources due to the subsurface migration of injected CO_2 is also a concern, especially as technologies develop for the enhanced recovery of oil and additional oil-in-place is available for recovery. This is important because first-generation projects are likely to be linked with enhanced oil and gas recovery operations, since such operations already have CO_2 injection infrastructure. The interests of mineral estate owners have been consistently upheld by courts and extensive regulatory and administrative regimes have been developed to protect oil and gas property rights.

Texas and California have diverging jurisprudence with respect to secondary recovery of oil (water injection into oil and gas fields), a close analogy to CO_2 injection. Texas is home to the 'rule of negative capture,' which states that less valuable substances (i.e. water) can migrate through the subsurface and replace more valuable substances (i.e. oil) without incurred liability, as long as the secondary recovery operation was properly carried out and received permission from the Texas Railroad Commission, the state agency in Texas regulating oil and gas activities (Corzelius v. Harrell, 143 Tex. 509 (1945); TXJUR OIL § 558). In California, the mineral estate owner whose

hydrocarbons are drained by an adjacent secondary recovery operation is entitled to damages (California Code of Civil Procedure, § 731c). However, where GS does not have a secondary recovery motivation and associated policy framework, the precedential value of this jurisprudence is unclear; CO_2 injected for GS purposes may not fit within the same liability framework as trespass in the secondary recovery context (Coddington, 2006).

Geologic Hazards

A final source of liability is geologic hazards, such as induced seismicity, subsidence, and ground heave. Induced seismicity is the concern that earthquakes could be induced because CO_2 injection affects the subsurface pressure. Injection-induced seismicity is a well studied phenomenon. One of the seminal experiments occurred at the Rangely Oil Field, which showed that variations in seismic activity could be produced by varying the fluid pressure in a seismically active zone (Raleigh et al., 1976). Of relevance to GS was that most of the induced seismic activity was microseismic of nature. The Rangely field is now being used for tertiary oil recovery with CO_2 injection and there has not been any reported seismic activity associated with the CO_2 injection. Subsidence could be caused by injected CO_2 degrading the geological structures supporting the surface, but this generally does not appear to be a concern. Finally, ground heave (the upward movement of the surface) could be a concern due to improper pressure regulation. Although there has been some litigation concerning subsidence, an analysis of historical case law did not find any documented cases on induced seismicity or heave. This may be due to the difficulties in proving causation. The risk of geologic hazards will generally be contained by regulations addressing the injection pressure. To some extent, these issues may be addressed by EPA Underground Injection Control regulations if the potential contamination of adjacent drinking water aquifers is in question.

Closure/Post-Closure: Long-term Liability

Because CO_2 is expected to remain in the subsurface for hundreds, if not thousands, of years, liability, and responsibility for damage, after the injection has been completed and the well has been closed becomes a concern. Risks to subsurface or surface resources

will be similar to those in the operational phase, although overall sequestration risk should decrease over time as the GS site becomes more secure with increased dissolution of the CO_2 in formation waters (over hundreds of years), and mineralization of CO_2 (over thousands of years). However, post-closure liability differs in several fundamental ways from operational liability. In the event of an accident or damage, there may be questions as to identifying responsible parties, delegating responsibilities for remediation, and how to apportion damages. In addition, long-term monitoring and management of the site after abandonment becomes a concern. In the oil and gas context, joint and several liability for damages to the surface is well supported by case law (19 A.L.R.2d 1025**).**

CCS industrial organization is an important consideration for long-term liability. In addition to the limited corporate lifetimes relative to the amount of time that CO_2 will remain in the subsurface., liability externalization by firms is an important consideration. Ringleb and Wiggins (1990) argue that large firms form subsidiaries as a means to protect parent firm assets from environmental and safety liabilities. Using U.S. Toxic Release Inventory data, Grant and Jones (2003) examine this contention and find significantly higher emission rates for subsidiaries. The role of government assumption of long-term liability for geologic sequestration is an uncertain condition that will influence treatment of liability over the post closure period and directly influence the applicability of financial instruments for long-term care.

Financial assurance requirements such as compulsory bonding are often an effective approach to address moral hazard for contractual and regulatory settings. The firm will post a bond that is released when regulatory compliance is completed. The EPA Underground Injection Control Program requires operators to post bonds to ensure plugging and abandonment procedures are followed. However, under the current regulatory system, once the well has been plugged, there is no further requirement of operator care.

Underlying each of these post-closure concerns is the evolution of the risk profile over time, the importance of remediation technologies and the ability of project developers and operators to manage the reservoir for sequestration safety. Knowing more about the

evolution of the risk profile over time and costs of remediation technologies are crucial for bounding and managing potential project liability and estimating the utility of various financial mechanisms. Although beyond the scope of this paper, understanding the role of backstop technologies to hedge against any future carbon price fluctuations could be important in the role GS plays in a larger carbon management regime. Neither California nor Texas have extensive experience with these types of mechanisms for long-term care, though both require the use of bonds to encourage plugging and abandonment for current underground injection wells.

Discussion

Jurisdictional differences in treatment of liability are examined in Table 2 for California and Texas. The largest differences surround potential damage to hydrocarbon resources and treatment of unitization. Neither state has the necessary framework for managing long-term liability from geologic sequestration.

		Responsible organization	California	Texas
Siting-associated Liability	Creating large and legal fields	State legislature, courts, state oil and gas office	Unitization statutes exist but are not universal	Unitization statutes exist but require 100% of interests to be in agreement (i.e. no compulsory unitization)
	Geophysical characterization, geophysical trespass	State oil and gas office	No case law	Many instances of case law dealing with this issue
Operational Liability	Inadvertent damage to hydrocarbons	State oil and gas office	Mineral estate owner entitled to damages (California civil code)	"Rule of negative capture" for unitized fields; mineral owner not entitled to damages
	Damage to groundwater	EPA and/or state underground injection control program	Groundwater owned by the state, managed by groundwater councils; unclear how GS would impact	Groundwater owned by property owner, but managed by the state; unclear how GS would impact
	Damage to human health or environment	OSHA, EPA and/or state underground injection control program	Precedent in state court tort rulings, strong consumer protectionist climate	Precedent in state court tort rulings
	Geologic hazards	EPA and/or state underground injection control program, state oil and gas office	Injection pressures regulated, but no case law; experience with ground heave, subsidence with oil and gas and geothermal operations; seismically prone regions in state	Injection pressures regulated, but no case law; relatively stable geology
Long-term Issues	Risks same as operational	Unsure	Uncertainty in determining responsible party	Uncertainty in determining responsible party
	Long-term responsibility for liability	Unsure	Uncertainty in determining responsible party	Uncertainty in determining responsible party

Table 2: Comparison between key GS liability issues in Texas and California

Given the unknown remediation costs, the uncertain scale of certain risks, and the unclear industrial organization of CCS, it is difficult to accurately assess the ramifications of different future liability regimes. However, analogs do exist and are important to consider. Other subsurface injection technologies with similar risks, such as damage to hydrocarbon resources or groundwater resources, have had to ensure long-term integrity of the geological formation. The assessment of existing liability regimes is helpful in determining the scale of potential liability damages and identifying steps for preventing such harm. Because CCS will likely be tied initially to the enhanced recovery of oil, the regulatory regime for oil and gas will play an important role in shaping the initial liability and regulatory context for CCS. Relevant and responsible actors and stakeholders will change over the life cycle of the project and understanding the particular liabilities and responsibilities of each is crucial for developing an integrated management framework. If a GS project begins as an enhanced oil recovery operation and is then transformed into a sequestration project, delineating the evolution of legal responsibility, rights of stakeholders and liability is key.

Specific difficulties with siting include the lack of administrative law to support the creation of large reservoirs for CO_2 injection and the lack of eminent domain powers. To rectify these issues, the state legislature would need to remedy this inadequacy with appropriate legislation. However, the current political climate and the unpopularity of employing powers of eminent domain in the wake of *Kelo v. City of New London* need to be considered. Difficulties in siting power transmission lines or other public infrastructure should be considered illustrative for future GS siting.

Additionally, public acceptance considerations are especially relevant for GS siting. As global benefits will be balanced by local risks, technology deployment will depend upon public acceptance. The scale of potential projects means that many stakeholders with diverse interests will need to be involved.

To the first order, operational concerns are similar to existing underground injection activities; however, the large volumes of CO_2, *in situ* buoyancy and potential leakage make treatment of geologic sequestration different. In Florida, subsurface injection of

municipal wastewater (a large volume, buoyant waste) has led to problems with leakage and can be considered a relevant analog for CCS (Keith *et al.* 2005). If natural gas storage projects are any indicator, management of leakage and migration of CO_2 in the subsurface can be tricky. Potential migration into other strata or areas outside a legally established reservoir is an important issue to consider.

Closure and long-term care is not well covered by the existing frameworks. Establishment of effective mechanisms depends upon understanding the evolution of risk over time and the cost of remediation technologies. Identifying responsible parties, be they private or public, over the post-closure care period is a crucial component for establishing financial responsibility and liability. Whether the transfer of responsibility and liability from private operators to the public is performance-based (for example, when reservoir pressure reaches a certain level) or prescriptive (for example, after 10 or 20 years), understanding the cost of remediation and the change of risk over time is crucial for estimating the cost of different management mechanisms (bonding, pooled funds, or other surety instruments).

Our analysis shows that the existing common law liability framework is, by and large, an unsatisfactory method for dealing with potential risks posed by CCS. Uncertainty of outcome, high transaction costs, and irregular resulting judgments all increase the CCS financial risk profile and public uncertainty that safety will be adequately managed. Not only are transaction costs high, with associated court fees, filings and burdens of proof, but the solutions often do not remedy the cause of the problem. Instead of *ex post* reliance on liability litigation, *ex ante* regulation can provide a more certain approach to avoiding CCS risks, providing benefits to industry, the financial community that must underwrite CCS projects, and public acceptance. On the other hand, the problem of “over regulating” relatively minor risks is of concern. Regulation must provide an approach that accurately reflects the real risk profile of CCS and is adaptable to new information that may emerge. Whether CCS technologies will be deployed at a level that would stabilize greenhouse gas emissions in such a regulatory environment is uncertain.

Conclusions

If CCS is to play an important role in reducing atmospheric emissions of greenhouse gases, it will need to be widely deployed. Such deployment necessitates prior resolution of legal and liability considerations. This paper has identified key liability considerations within siting, operation, and closure phases of geologic sequestration projects. Jurisdictional differences between California and Texas were examined, with significant differences found both in amount of case law and treatment of damage of hydrocarbons. With respect to groundwater damage, it is uncertain how CCS related activities would be treated. While identifying parties responsible for damage during the siting and operational phases is clear-cut, responsibility after closure is ambiguous. It remains uncertain when responsibility will remain with the operator or be transferred to the public, yet resolution of this issue is key for establishing post-closure care regimes. Additionally, the cost of remediation technology is important for the establishment of post-closure care. Each of these issues must be resolved if CCS is to be effectively deployed.

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