Study of Legal Issues Relating to Risk and Liability in Connection with Carbon Capture and Storage

The CCS Alliance

July 23, 2008

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This study reviews major potential legal issues associated with the capture, transport, underground injection and long-term storage of carbon dioxide (CO_2). It has been prepared for the CCS Alliance by Hunton & Williams LLP, and expands upon the CCS legal issues chapter of the 2008 National Coal Council report, which was also prepared by Hunton & Williams.

The discussion that follows will outline the phases of carbon capture and storage (CCS) and the possible pathways to risk, review legal issues that might arise should something go wrong in the CCS chain, and discuss the legal regimes that apply or are potentially applicable to CCS.

1. Introduction

If atmospheric CO_2 emissions are controlled, carbon capture and storage is the only tool on the horizon to address very large quantities of CO_2 emissions from coal-fired facilities. However, it is a tool that requires significant additional research and the definition of a stable legal regime.

If the country is going to control CO_2 emissions, it needs to accelerate CCS research. There is uncertainty about whether we can know enough in the time by which some policy makers would like CCS to start, to have sufficient comfort that CO_2 storage on the scale envisioned will work. Any legal regime that imposes restrictions on carbon emissions must recognize the status and development of technical understanding regarding CCS. Moreover, the legal regime applicable to CCS activities should be simple, clear, and as unified as possible. Because the storage of carbon emissions to address climate change is an activity to address a social purpose rather than serve an economic goal, the applicable legal and liability regimes should be designed to encourage rather than discourage CCS development.

CCS involves the capture, transport, underground injection, and long-term storage of CO_2. The technology and engineering capability exists today to capture and geologically sequester CO_2, and it has been deployed in a few instances on a relatively large scale.[1] For example, the Sleipner natural gas processing project in Norway, the In Salah natural gas project in Algeria, and the Weyburn enhanced oil recovery (EOR) project in Canada currently store 1-2 million metric tons of CO_2 per year in underground formations.[2] Other projects are being planned worldwide. However, CCS has not yet been demonstrated in conjunction with large coal-fired power plants, nor on the scope and scale required to meaningfully address CO_2 emissions.

The United States has nearly 1,500 coal-fired electric generating units,[3] which collectively produce about half of the electricity used nationwide each year. Coal-fired electricity production accounts for 36 percent of the United States' CO_2 emissions each year.[4] Coal also is a vital source of energy for other industrial processes, such as the manufacture of staples like steel and cement.

Whether to apply CCS technology to new coal-fired generation is an issue coming to a head across the United States. Some States already have passed laws designed to reduce greenhouse gas emissions, and Congress has signaled that it may soon do the same. The U.S. Supreme Court recently ruled in *Massachusetts v. EPA* that the federal government has the authority to regulate CO_2 and other greenhouse gases as pollutants under the Clean Air Act. Financial institutions now are factoring in the risks from CO_2 emissions in their underwriting processes. New coal-fired power plants are facing increasing difficulties in gaining approval from State authorities. Various parties already are acting to address GHG emissions.

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[1] *See* Stephen Pacala and Robert Socolow, *Stabilization Wedges: Solving the Climate Problem for the Next 50 Years with Current Technologies*, 305 SCIENCE 968 (2004).

[2] *Special Report on Carbon Dioxide Capture and Storage*, INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE (2005) at 19.

[3] Energy Information Administration, U.S. Department of Energy, *Table 2.2, Existing Capacity by Energy Source* (2006) *at* http://www.eia.doe.gov/cneaf/electricity/epa/epat2p2.html.

[4] Based on average CO_2 emissions between 1995-2006, Energy Information Administration, http://www.eia.doe.gov/oiaf/1605/ggrpt/index.html.

Even emission reductions at existing coal-fired facilities have become more difficult to make from a legal standpoint, given changes in legal interpretation of New Source Review (NSR) requirements under the Clean Air Act. Plant maintenance that results in efficiency improvements - such as replacement of turbine blades with more efficient ones or installation of new feedwater condensers, fans, and other equipment that can result in producing the same amount of electricity with fewer CO_2 emissions - can trigger NSR, requiring installation of expensive equipment to reduce other air emissions. This deters investment in efficiency. Installation of CCS equipment at existing power plants may trigger NSR as well.

As the country continues to consider responses to greenhouse gas emissions, the issue becomes no easier. The U.S. population is expected to grow by 60 million by 2030. During that time, electricity demand will increase by 33 to 50 percent.[5] An even more populous country, and a far more populous world, will need electricity, transportation, food, and other things that require more energy. Meeting this demand raises concerns over America's energy security, as the prices of oil and natural gas continue to rise. Alternatives such as nuclear and renewable energy, in conjunction with demand management measures, even if deployed at unprecedented levels, would not be enough to prevent the need for new coal-fired facilities.

CCS can offset the potential climate impacts from the CO_2 emissions associated with coal-fired power plants and ensure a vital role for America's 250-year supply of coal in meeting future energy demand and providing energy security. The industrial-scale deployment of CCS hinges on identifying and resolving key regulatory and liability issues, given the risks involved with capturing, transporting, injecting, and storing large amounts of CO_2.

The following discussion will outline the phases of carbon capture and storage and the possible pathways to risk, discuss what might happen should something go wrong in the CCS chain, and discuss the legal regimes that apply or are potentially applicable to CCS.

[5] Energy Information Administration, *Annual Energy Outlook 2007, at* 138.

2. Phases of Carbon Capture and Storage and Potential Risks

The capture, transport, underground injection, and long-term storage of CO_2 may pose potential risks in one of three ways: through leaks, pressure, or trespass or other torts. The risks may be to human health, the environment, or property, including risks of human exposure, groundwater contamination, subsurface resource damage, trespass, and induced seismicity events and surface alteration. It also poses business risks. For example, depending on how a regime is implemented to restrict CO_2 emissions, businesses may need to cease operation if CO_2 emissions are not controlled or are accidentally released. There is business interruption risk, as well as the potential loss of carbon credits.

Exposure to high concentrations of CO_2, typically 7-10 percent or greater by volume in air, can be harmful to humans, as well as animal and plant life.[6] CO_2 is denser than air and, upon release from a pipeline or an underground storage site, can accumulate in potentially dangerous concentrations in low-lying areas. Population density, local topography, and local meteorological conditions are key factors in determining the likelihood of exposure to high concentrations of CO_2, should high concentrations be released to the atmosphere. If released, CO_2 will vaporize over a relatively short period of time.

The injection and long-term storage of CO_2 can contaminate underground sources of drinking water. Injected CO_2 can migrate from an underground storage site through undetected faults and fractures or through improperly drilled and managed injection wells. It may enter directly into aquifers or displace brines or other substances into aquifers. Injected CO_2 also can displace toxic metals, sulfates, or chloride into aquifers. The likelihood of contamination of underground sources of drinking water by displaced brine or chemicals can be reduced if there is proper site characterization, selection, and monitoring.[7] In addition to affecting water supply,

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[6] *Special Report on Carbon Dioxide Capture and Storage*, INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE (2005), at 12.

[7] *Id*. at 247.

the accumulation of leaked CO_2 just beneath the surface can cause soil acidification and displace oxygen in soils.

The migration of CO_2 also can damage other underground resources, such as hydrocarbon resources during an EOR operation. As would be the case with drinking water contamination, the CO_2 may displace brine, which could foul oil or gas resources. There is precedent in oil extraction and underground storage of natural gas for recovery of damages under tort law, as well as established protocols for evaluating damage to cropland or forests.[8]

The injection of CO_2 also poses slight risk of triggering seismic events or causing land deformation or subsidence. An induced seismic event can compromise the integrity of the storage site by damaging the injection well and creating or exacerbating faults.[9] Induced seismic events and other geologic hazards, such as ground heave, usually are triggered by excessive injection pressures and have been documented at hazardous waste disposal wells, oil fields, and other sites. In 1966, two earthquakes with Richter magnitudes of 5.1 and 5.2 were triggered by injection near Denver, Colorado.[10] Injection of supercritical CO_2 poses special considerations because it can interact with surrounding rock and water in a storage site and reduce permeability. This can ensure its permanent storage, but also can result in pressure build up that potentially could lead to seismic activity. Induced seismic activity may be prevented through proper siting, installation, operation, and monitoring.[11]

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[8] Elizabeth J. Wilson, *et al.*, *Liability and Financial Responsibility Frameworks for Carbon Capture and Sequestration*, WORLD RESOURCES INSTITUTE (December 2007).

[9] *Special Report on Carbon Dioxide Capture and Storage*, INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE (2005), at 13.

[10] Joel Sminchak and Neeraj Gupta, *Issues Related to Seismic Activity Induced by the Injection of CO_2 in Deep Saline Aquifers*, FIRST NATIONAL CONFERENCE ON CARBON SEQUESTRATION, NATIONAL ENERGY TECHNOLOGY LABORATORY (2001), *at* http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/p37.pdf. (“Seismic activity was first linked to deep well injection activities near Denver, Colorado, in 1962. Since then, seismic activity triggered by injection wells has been noted at locations worldwide. … Most notably, two earthquakes with Richter magnitude of 5.1 and 5.2 were triggered in Denver, Colorado, in 1966.”).

[11] *Id*.

With proper site characterization, design and operational standards, and management of CCS activities, most risks are expected to be manageable. However, until a track record is developed of sequestering CO_2 on the scale and in the formations envisioned in legislation to reduce carbon emissions, there is likely to be hesitance among potential investors and risk managers (such as insurers) to participating in CCS projects.

A. Capture

The capture of CO_2 typically occurs on-site at a power plant or other large source of emissions. Once the CO_2 is captured, it will be compressed to a supercritical state for efficient transport. For the volumes emitted by a major coal-fired power plant, transportation is envisioned to be predominantly by pipeline.

The capture phase presents two primary risks. First, while capture technologies are expected to be effective, their use on large-scale coal-fired power plants will in some cases be a new application. There may be technical issues. Depending on the regulatory scheme or schemes in place, it is unclear whether plant operations might have to be interrupted while capture equipment is being repaired. This issue applies not only to the capture phase, but to all CCS phases. Second, there will be high costs and energy use from capture and compression technologies.

CO_2 capture is possible either pre-combustion or post-combustion. The primary pre-combustion technology envisioned is integrated gasification combined cycle (IGCC), through which coal is partially combusted to produce a syngas, from which CO_2 may be relatively easily separated and captured. Post-combustion carbon capture may happen through one of several technologies.

Post-combustion capture of CO_2 presents a variety of technical challenges. The low pressure and dilute concentration requires a high volume of gas that needs to be treated to separate the CO_2. Trace impurities in the flue gas can slow the capture process and create risks in pipeline transport and storage. In addition, compressing the captured CO_2 for transport and underground injection uses significant amounts of energy and increases costs. The National Energy Technology Laboratory (NETL) indicates that use of aqueous amine capture technology, one of several that could come into use, would "raise the cost of electricity from a newly-built supercritical pulverized coal power plant by 84 percent, from 4.9 cents/kWh to 9.0 cents/kWh."[12]

The pre-combustion capture of CO_2 is possible with integrated gasification combined cycle (IGCC) technology.[13] IGCC results in lower emissions of sulfur dioxide, particulates, and mercury by turning coal into a gas and removing impurities from the gas prior to combustion. NETL estimates that carbon capture would increase the cost of electricity at IGCC plants by 25 percent, from 5.5 cents/kWh to 6.5 cents/kWh.[14] Even without carbon capture, electricity at IGCC plants is expected to be more expensive than at conventional plants because of the increased costs to build an IGCC plant, versus a new pulverized coal plant.

IGCC technology offers co-benefits, such as the production of hydrogen, which can be burned as a clean source of energy. Carbon capture is more efficient when done pre-combustion, because a relatively concentrated CO_2 stream can be captured before it is mixed with air through the combustion process.

In addition to technology hurdles, the potential of climate change regulation limiting CO_2 emissions raises some concern over business interruption risk in cases where capture and compression equipment goes offline. To avoid facing penalties for exceeding emissions limits, emitting facilities may have to choose between suspending operations or purchasing additional emissions allowances or offset credits to cover excess emissions.

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[12] National Energy Technology Laboratory, *Carbon Sequestration: CO_2 Storage, at* www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html

[13] A third method for the capture of CO_2 is known as oxy-combustion, which combusts coal in an enriched oxygen environment.

[14] National Energy Technology Laboratory, *Carbon Sequestration: CO_2 Storage, at* www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html.

B. Transportation

A main risk with CO_2 transportation, which is expected primarily to occur via pipeline, is corrosion that could necessitate expensive repairs and may bring about some CO_2 leakage into the atmosphere. Pipeline length will vary depending on the proximity of the generating facility to the geologic storage site. The transportation of CO_2 by pipeline is not likely to present any high-probability and high damage risks though existing regulatory frameworks may not be sufficient for its management.

Large-scale CCS schemes will need a system for transporting CO_2 from capture sites to long-term storage facilities. This can be done in limited quantities by truck, rail and ship. However, moving the enormous quantities of CO_2 indicated by widespread implementation of CCS technologies may require a dedicated interstate pipeline network especially if CCS is applied to existing coal-fired facilities, which may or may not be located near long-term storage sites. Alternative modes would be, in many cases, logistically impractical. CO_2 pipelines are similar to natural gas pipelines, requiring the same attention to design, monitoring for leaks, and protection against overpressure, especially in populated areas. There are about 3,600 miles of CO_2 pipeline currently in operation in the U.S. in about a dozen States, though the majority is located primarily in Texas, New Mexico, and Wyoming. The existing pipeline infrastructure can transport approximately 40 million metric tons of CO_2 per year, which today is used for EOR and other industrial purposes.

Considerable uncertainty continues to be expressed over the suitability of geological formations to sequester the captured CO_2 and the proximity of those formations to specific sources. Analyses suggest the vast majority of CO_2 could be stored in reservoirs directly underlying sources and that much of the rest would not have to be transported more than 100 miles. Were this the case, the need for pipelines would be limited to onsite transportation and a relatively small number of long-distance pipelines, only a few of which would be interstate.[15]

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[15] *See* Paul W. Parfomak and Peter Folger, *Carbon Dioxide (CO2) Pipelines for Carbon Sequestration*: EMERGING POLICY ISSUES, CONGRESSIONAL RESEARCH SERVICE RL33971, (April 19, 2007).

Indeed, there are questions over the extent to which long pipeline transportation will be required at all, particularly in the early going, when most CCS projects are likely to be proposed in conjunction with power plants or other large emitting industrial facilities with on-site injection and sequestration capability. Research suggests that 77 percent of CO_2 captured from North American sources could be stored in reservoirs directly beneath these sources, and an additional 18 percent may be stored within 100 miles of storage reservoirs.[16]

But uncertainties over the long-term storage capabilities of some underground reservoirs may require transporting CO_2 to proven locations.[17] There is analysis that suggests that captured CO_2 may need to be sequestered, at least initially, in more centralized reservoirs to reduce potential risks associated with CO_2 leaks. However, many coal-fired power plants are situated in regions where there are high expectations of having CO_2 sequestration nearby, which would hold transport and injection costs overall to a lower percentage of total CCS costs.[18] The costs of pipelines that would need to be built, however, were seen as highly variable due to physical and political considerations.

The existing network of CO_2 pipelines for EOR is sited mostly in remote areas where the population is accustomed to large energy infrastructure. Commercial-scale CCS deployment could require a much larger infrastructure, with one estimate predicting 100,000 miles of new pipeline.[19] By comparison, there are nearly 500,000 miles of natural gas and hazardous liquid transmission pipeline in the United States. Many potential CO_2 sources such as power plants are located in populated regions.

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[16] R.T. Dahowski, *et al.*, *A North American CO_2 Storage Supply Curve : Key Findings and Implications for the Cost of CCS Deployment*, PROCEEDINGS OF THE FOURTH ANNUAL CONFERENCE ON CARBON CAPTURE AND SEQUESTRATION (2005).

[17] Jennie C. Stevens and Bob Van Der Zwaan, *The Case for Carbon Capture and Storage*, ISSUES IN SCIENCE AND TECHNOLOGY (Fall 2005) at 69-76.

[18] *See* Figure 2.7, Mark Anthony de Figueiredo, *The Liability of Carbon Dioxide Storage*, MASSACHUSETTS INSTITUTE OF TECHNOLOGY, (February 2007) at 33.

[19] Edison Electric Institute, written testimony to the House Select Committee on Energy Independence and Global Warming, September 21, 2007.

CO_2 reaches a liquid state in combinations of high pressure and low temperature and generally is transported in liquid or gas form.[20] The purity of the CO_2 being transported is important, as the presence of hydrogen sulfide can increase the likelihood of pipeline corrosion. Furthermore, CO_2 and water mix to form carbonic acid, which can be highly corrosive. There were no injuries or fatalities resulting from the twelve reported safety incidents from CO_2 pipelines reported from 1986 to 2006.[21] By comparison, there were 5,610 incidents causing 107 fatalities and 520 injuries related to natural gas and hazardous liquids (excluding CO_2) pipelines.[22] As the CO_2 pipeline network expands, the rate of incidents is predicted to be much more similar to that for natural gas pipeline transmission.[23] Other analysts consider that CO_2 pipelines are likely to be safer than other federally-regulated pipelines.[24]

The U.S. Department of Transportation (DOT) has primary authority to regulate interstate CO_2 pipeline safety under the Hazardous Liquid Pipeline Act of 1979.[25] Under the Act, the DOT regulates the design, construction, operation and maintenance, and spill response planning for CO_2 pipelines.[26] The DOT administers pipeline regulations through the Office of Pipeline Safety within the Pipeline and Hazardous Materials Safety Administration (PHMSA). Under DOT regulations, CO_2 is listed as a Class 2.2 (non-flammable gas) hazardous material,[27] but the agency applies nearly the same safety requirements to CO_2 pipelines as those carrying

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[20] *Special Report on Carbon Dioxide Capture and Storage*, INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE (2005), at 181.

[21] Office of Pipeline Safety, *"Distribution, Transmission, and Liquid Accident and Incident Data"* (2007).

[22] *Id*.

[23] *See* Paul W. Parfomak and Peter Folger, *Carbon Dioxide (CO_2) Pipelines for Carbon Sequestration*: EMERGING POLICY ISSUES, CONGRESSIONAL RESEARCH SERVICE RL33971 (April 19, 2007).

[24] See J. Barrie, R. Brown, P.R. Hatcher, and H.U. Schellhase, *"Carbon Dioxide Pipelines: A Preliminary Review of Design and Risks,"* Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies (Vancouver, Canada, Sept. 5-9, 2004, p.2.)

[25] 49 U.S.C. § 601.

[26] 49 C.F.R. §§ 190, 195-199.

[27] 49 C.F.R. § 172.101.

hazardous liquids such as crude oil, gasoline, and anhydrous ammonia.[28] At the State level, safety regulation of CO_2 pipelines is similar to that applied to hazardous liquid pipelines, an indication that the carriage of CO_2 is not considered to be hazardous.

Other regulatory models, such as those currently used for oil and natural gas pipelines, could be adapted for an expanded CO_2 pipeline system.[29]

C. Injection and Long Term Storage

CCS risks are most likely to occur during long-term storage. The potential risks include leakage, over-pressurization, migration of the CO_2 plume, or displacement of other fluids and constituents with the potential to impact underground sources of drinking water.

Storage of CO_2 is expected to occur primarily at depths below 800 to 1,000 meters. At these depths, CO_2 is at a supercritical state with a liquid-like density that enables its secure storage in the pores of sedimentary rocks. When stored underground at these depths, its density will range from 50-80 percent of the density of water. As a result its buoyancy and viscosity will tend to drive it upward unless it is properly contained.

Proper containment depends on a highly porous and permeable underground formation with a thick seal or caprock to prevent leakage into overlying formations. NETL describes the following as suitable for geologic sequestration:

- "*Caprock trapping*. An impermeable layer of low-porosity rock serves as a barrier against upward migration of CO_2.
- "*Pore space trapping*. Through capillary and surface tension forces, droplets of CO_2 become affixed into a rock pore space (primarily for oil and gas formations, and also for saline formations to some extent).

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[28] 49 C.F.R. § 195. *See also* Paul W. Parfomak and Peter Folger, *Carbon Dioxide (CO_2) Pipelines for Carbon Sequestration: Emerging Policy Issues*, CONGRESSIONAL RESEARCH SERVICE RL33971 (April 19, 2007).

[29] *See* Testimony of the Hon. Joseph T. Kelliher, Chairman, Federal Energy Regulatory Commission, Hearing To receive testimony on carbon capture, transportation, and sequestration and related bills, S.2323 and S.2144, United States Senate Committee on Energy and Natural Resources (January 31, 2008).

- "*Solubility trapping*. Dissolution of CO_2 in saline water, as CO_2 is soluble in brine. For example, at 1900 psi and 30,000 ppm TDS, one gallon of brine holds 0.4 pounds of CO_2 (primarily for saline formations and basalt formations, and also for oil and gas formations to some extent).

- "*Mineralization*. Once in solution, CO_2 will react, albeit at a slow rate, with dissolved minerals to form solid mineral carbonates (primarily for high magnesium content basalts, and for saline formations).

- "*Adsorption*. Unmineable coal seams offer a unique storage mechanism as CO_2 molecules adsorb onto the surface of the coal. Adsorbed CO_2 exists as a condensed liquid and is immobile so long as the formation pressure is maintained."[30]

Typically, CO_2 is contained by one of several mechanisms: trapped below an impermeable, confining layer known as "caprock"; retained in an immobile phase sealed in the pore spaces of the storage formation; dissolved in the in situ formation fluids; or absorbed into organic matter contained in coal and shale.[31] Over longer periods of time, CO_2 may react with minerals in the storage formation and caprock to produce carbonate materials. The length of time for this to occur depends on a variety of physical conditions, including the chemical composition of the formation. The containment of CO_2 in a geological reservoir is predicted to be *very likely* to exceed 99 percent over 100 years, and *likely* to exceed 99 percent over 1,000 years.[32] As a result, CCS projects are predicted to be unlikely to threaten human life or cause many of the other surface or subsurface disturbances likely to occasion liability.[33]

Where a storage site's containment is breached, leakage can occur abruptly, through injection well failure or up an abandoned well, or gradually, through undetected faults, fractures,

[30] *Carbon Sequestration Program Environmental Reference Document*, NATIONAL ENERGY TECHNOLOGY LABORATORY, (February 2007) *at* 2-33.

[31] *Special Report on Carbon Dioxide Capture and Storage*, INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE (2005) at 197.

[32] *Id.*, at 14.

[33] Sally Benson, *Lessons Learned from Natural and Industrial Analogues for Storage of Carbon Dioxide in Deep Geological Formations,* Report LBNL-51170, LAWRENCE BERKELEY NATIONAL LABORATORIES (2002).

or wells.[34] The U.S. Government Accountability Office has reported that most leakage from injection wells occurs through improper well design and maintenance, such as from faults in well casing, excessive injection pressure, the presence of improperly abandoned wells, corrosion of the well casing or tubing, and other aspects.[35] Wells typically are sealed with cement plugs that can degrade over time from the build up of carbonic acid, which forms when CO_2 is injected in subsurface formations containing brine.[36]

A monitoring, mitigation, and verification (MMV) regime can ensure the secure, long-term storage of CO_2. MMV regimes are designed to measure and track the amount of stored CO_2, monitor the storage site for leaks or other deterioration of the storage site, and verify that the amount of CO_2 that is being securely stored and not posing a threat to the surrounding area.[37] Such MMV regimes include "assessing the integrity of plugged or abandoned wells in the region; calibrating and confining performance assessment models; establishing baseline parameters for the storage site to ensure that CO_2-induced changes are recognized; detecting microseismicity associated with the storage project; measuring surface fluxes of CO_2; and designing and monitoring remediation activities."[38]

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[34] *Special Report on Carbon Dioxide Capture and Storage*, INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE (2005), at 13.

[35] U.S. General Accounting Office, *Deep Injection Wells: EPA Needs To Involve Communities Earlier and Ensure that Financial Assurance Requirements Are Adequate*, GAP-03-761 (2003).

[36] S. Taku Ide, et al., *CO_2 Leaking Through Existing Wells: Current Technology and Regulations*, PROC. EIGHTH INTERNATIONAL CONF. GREENHOUSE GAS CONTROL TECHS. (2006).

[37] *Carbon Sequestration Program Environmental Reference Document*, NATIONAL ENERGY TECHNOLOGY LABORATORY, (February 2007) *at* 2-10.

[38] *Carbon Sequestration Program Environmental Reference Document*, NATIONAL ENERGY TECHNOLOGY LABORATORY, (February 2007) *at* 2-6.

3. CCS Legal and Regulatory Considerations

There is as yet no single coordinated framework covering the siting, underground injection, closure, and long-term storage associated with CCS. Should a new federal regulatory framework emerge, it is not clear how comprehensive it may be, or how it may interact with State regulatory regimes. Thus, it has yet to be determined via what statutory and regulatory provisions CCS project owners and operators may be held accountable. In addition, common law theories such as trespass may apply in the CCS context.

The U.S. Environmental Protection Agency (EPA) currently regulates CCS injections under the Underground Injection Control (UIC) program, the authority for which is provided under the Safe Drinking Water Act (SDWA).[39] Other federal programs may apply as well, as described below.

States are most likely to regulate CCS activities under statutes that parallel federal statutes and were enacted to satisfy requirements in federal laws that in order to have status as the lead regulator, States would need to adopt laws no less stringent than federal law. However, States also may adopt other laws affecting CCS.

A. Federal

i. UIC Program

The SDWA establishes minimum federal regulations to protect drinking water sources. The Underground Injection Control (UIC) program within the SDWA regulates the discharge of fluids beneath the surface to ensure that any underground injection activities will not endanger underground sources of drinking water.[40]

[39] 42 U.S.C. §300h *et seq*.

[40] 42 U.S.C. §300h(b)(1).

There are five classes of injection wells established by the EPA in the UIC program:[41]

- Class I: Hazardous wastes, industrial non-hazardous liquids, or municipal wastewater beneath the lowermost underground sources of drinking water;

- Class II: Brines and other fluids associated with oil and gas production, and hydrocarbons for storage beneath the lowermost underground sources of drinking water;

- Class III: Fluids associated with solution mining of minerals beneath the lowermost underground sources of drinking water;

- Class IV: Hazardous or radioactive wastes into or above underground sources of drinking water;[42] and

- Class V: All injection wells not included in Classes I-IV, including experimental wells. In general, Class V wells inject non-hazardous fluids into or above underground sources of drinking water and are typically shallow, on-site disposal systems. However, there are some deep Class V wells that inject below underground sources of drinking water.

Regulations promulgated under SDWA establish minimum requirements for all injection wells. These requirements generally pertain to site and injection formation characterization, well construction, operation, testing, and periodic monitoring and reporting.

Under the UIC program, States that develop their own UIC programs that meet the requirements of the federal program can assume primary responsibility for implementation and enforcement. To date, a total of 33 States have been granted primacy, seven States operate under a joint federal/State program, and in ten states EPA has sole responsibility for overseeing the UIC program. The elements for a State to assume primacy for administering the UIC program

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[41] 40 C.F.R. 144-148.

[42] These wells are banned unless authorized under a federal or State groundwater remediation project.

are outlined in the regulations at 40 C.F.R. §145. Before EPA will approve primacy, each State must make an adequate demonstration that its program is at least as stringent as EPA's UIC programmatic requirements. A State must also submit an application to EPA with a letter from the Governor, a complete description of the State program (e.g., well classes, permitting and inspection procedures, enforcement authority, etc.), and a memorandum of agreement between the State and the EPA Regional Administrator. Any changes to EPA's UIC program, including the likely creation of a new class of UIC wells for CO_2 injection (as discussed below), will likely require States who wish to administer CO_2 injection wells to seek revised approval.

The UIC regulations vary depending upon the well class, with Class I wells being the most stringently regulated and Class II and V, the least stringently regulated. Given the increased risks associated with Class I wells, EPA requires a greater level of care and rigor associated with siting, construction, operation, monitoring and testing, reporting and record keeping. Class I hazardous waste wells are subject to both SDWA and the Resource Conservation and Recovery Act (RCRA). Even if administered at the state level, operators of Class I hazardous waste wells must receive approval from the regional EPA office of a "no-migration demonstration" as required by RCRA. A no-migration demonstration is designed to ensure zero contamination and requires operators to demonstrate that wastes will not migrate from the injection zone for at least 10,000 years or will be rendered harmless via chemical transformation.[43]

The siting of a hazardous waste well must also undergo a more extensive area of review (AoR) of the surrounding area to identify artificial penetrations that could result in leaks. Unlike most Class I wells with a one-quarter mile AoR, hazardous waste wells must meet a minimum two mile AoR. Hazardous waste wells also require post-closure care plans that require long-term monitoring and specific and comprehensive financial assurances to address potential leakage into USDWs. The monitoring and posting of financial assurance mechanisms for a hazardous waste wells can be significant and extend out over many years. In the case of CO_2, EPA has indicated

[43] 40 CFR 144.12b. *See also* E. Wilson, *et al., Considerations for a Regulatory Framework for Large-Scale Geologic Sequestration of Carbon Dioxide: A North American Perspective*, 7TH INTERNATIONAL CONFERENCE ON GREENHOUSE GAS CONTROL TECHNOLOGIES, VANCOUVER, CANADA (November 2004).

its interest in the possibility of requiring post-closure care for as long as 300 years - far longer than any other UIC well - due to the potential threats from CO_2 posed long after the injection phase. However, establishing such a long period of post-closure care poses serious legal and practical challenges. Therefore, short of a legislative fix, EPA will likely provide States with some flexibility in establishing post-closure requirements, including possibly the adoption of performance-based requirements such as a "reservoir pressure point" where the CO_2 is no longer subject to mobilization and therefore no longer presents an endangerment.

Currently, financial responsibility under the UIC program may be demonstrated using number of different instruments including insurance, irrevocable letters of credit, surety bonds, and trust funds. 40 C.F.R. §§144.28 and 144.63. Each of these instruments has its limitations and present special challenges if extended to the employment of CO_2 injection on a large commercial scale.[44] Therefore, a new approach to CCS for CO_2 injection is warranted that balances the need of ensuring adequate financial responsibility with the unique nature and reduced risks associated with deep underground storage of CO_2.

Class II wells involve the injection of fluids, such as brines, brought to the surface during oil and gas production, and CO_2, used to enhance oil and gas recovery or, alternatively, the injection and storage of hydrocarbons. In contrast to Class I wells, the operation of Class II wells poses fewer risks and, therefore, has less stringent requirements, including not requiring ongoing post-closure care requirements.

None of the current five classes of UIC wells is particularly well suited for CCS, due to the unique characteristics of CO_2 and the massive scale and long-term duration of future commercial projects. The Interstate Oil and Gas Compact Commission (IOGCC) has proposed that CCS be regulated under the existing Class II program, because many states have a long history of regulating CO_2 injection for enhance oil recovery (EOR). While many believe that the requirements for Class I wells are too stringent for CO_2 wells, others believe that the requirements for Class II are not stringent enough primarily because of the scaling concerns that

[44] See L. Patton and J. Joyce, *Hazardous Waste Financial Assurance: A Comparison of Third-Party Risk Management Mechanisms - Suggestions for Reform*, BNA's Environmental Due Diligence Guide (2008).

are unique to commercial-scale CO_2 injection. Thus, as a temporary measure, in March 2007, the EPA issued final guidance for processing permit applications for pilot projects to test CO_2 injection technologies as Class V wells, which authorizes State, Tribal, and EPA Regional offices to issue Class V permits beginning in March 2009.[45] EPA intends to gather data and information from these pilot projects to develop more targeted requirements for commercial-sized projects.

Failure to comply with the operating, reporting, or closure requirements of the UIC program could subject an owner/operator to administrative fines of up to $6,000 per violation per day for Class II wells and up to $11,000 per violation per day for all other wells, up to a $157,500 ceiling. Civil penalties may be up to $32,500 per violation per day without a ceiling. As well, the EPA Administrator has broad authority under SWDA to take whatever action necessary to prevent or mitigate against contaminants that are present in or may enter a public water system or USDW and which may present an imminent and substantial endangerment to public health. Where an endangerment finding is made, and the State and local authorities have failed to act, EPA has the authority to order temporary or permanent corrective action, including ordering an owner/operator to shut down an operational injection well, remediate a contaminated USDW, or replace a public drinking water source.

The EPA is planning to issue a proposed rule on the injection of CO_2 for CCS under the UIC program in the Summer of 2008 with a final rule expected by late 2009 or 2010. Among the key issues in the rulemaking are the size of AoR the EPA requires applicants to review in advance of injection and storage, as discussed above; post-closure care requirements, including the period of financial responsibility; and the potential application of RCRA and the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund).[46]

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[45] Final Guidance -- Using the Class V Experimental Technology Well Classification for Pilot Geologic Sequestration Projects -- UIC Program Guidance (UICPG #83), U.S. Environmental Protection Agency (2007), *at* http://www.epa.gov/safewater/uic/pdfs/guide_uic_carbonsequestration_final-03-07.pdf.

[46] The EPA excludes certain substances from RCRA under 40 C.F.R. 261.4. CO_2 is not expressly excluded, but it also is not expressly included in the list of hazardous substances in 40 C.F.R. 261.3.

In the rulemaking, the EPA is considering creating a new "Class VI" category well that would take into account the special considerations involved with CCS, including the volume of CO_2 that potentially could be injected, its corrosivity, as well as the unusual buoyancy and viscosity of supercritical CO_2. The EPA is considering other issues such as the need to require secondary containment (i.e. a second formation of "caprock" above the initial formation), which could limit the eligibility of potential storage sites, raise costs due to extra transportation, and add to the administrative burden of regulating site characterization.

The EPA also is assessing what to require with regard to post-closure maintenance, monitoring and verification, especially in cases where the underground CO_2 plume has migrated. This may or may not involve the use of tracers or special isotopes that can be mixed in with the CO_2 to identify it if it mixes in with other underground material. Moreover, the EPA is likely to require CCS wells to use corrosion-resistant materials.

As mentioned above, the IOGCC, which comprises 31 States, proposed giving States primacy under the UIC program and continuing to regulate the injection of CO_2 for EOR as Class II wells. For CO_2 injection without EOR, IOGCC proposed treating CO_2 like natural gas, which is considered a commodity and has received a statutory exemption from the SDWA. The regulation and permitting of natural gas storage is generally conducted at the State level, and natural gas injection wells are often regulated as Class II wells under appropriate State UIC programs.[47] Post-closure monitoring is generally not required, because upon closure as much natural gas as possible will have been drawn from the reservoir. Alternatively, the IOGCC proposed a new sub-classification for Class II wells or a new classification of wells to be established. Above all, IOGCC opposed regulated CO_2 injection for CCS as a Class I or Class V well.

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[47] Anhar Karimjee and Bruce J. Kobelski, *An Overview of Technical and Regulatory Considerations for Geologic CO2 Sequestration*, U.S. ENVIRONMENTAL PROTECTION AGENCY.

ii. CERCLA

Policy makers should take care to avoid the applicability of the federal Superfund program to injections of CO_2. Superfund is a liability scheme, rather than a regulatory scheme, that provides for joint, strict, and several liability for the “release” of a “hazardous substance.” A hazardous substance is defined by the so-called “list of lists” - if a substance is regulated or controlled under one of a number of other federal statutes, it is a hazardous substance under Superfund.

Superfund has been roundly criticized for many years for being too costly and for taking too long to produce actual clean-ups. These problems are fed by the program’s joint, strict, and several liability scheme which has led to protracted, costly lawsuits over who is responsible for cleaning up how much of a site. The inquiry potentially may involve hundreds of parties in some cases. For CCS there are not likely to be hundreds of parties involved in a chain of activity but potential lawsuits nevertheless could be thorny.

Superfund's chequered history has bred a history of criticism. President Clinton said in 1993 that "The Superfund has been a disaster. All the money goes to the lawyers, and none of the money goes to clean up the problems that it was designed to clean up."[48] The New York Times editorialized in 1994, "It is hard to think of a government program with a wider gulf between ambitions and results than Superfund. . . . It has failed the efficiency test: of the $13 billion spent by governments and companies, one-fourth has gone to what are euphemistically known as "transaction costs" -- fees to lawyers and consultants, many of them former Federal officials who spun through Washington's revolving door to trade their Superfund expertise for private gain. Finally, it has failed the cost-effectiveness test: time and again, slightly

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[48] *See* David Rosenbaum, *Business Leaders Urged by Clinton to Back Tax Plan*, NEW YORK TIMES (February 12, 1993)

contaminated soil that might have been paved over or otherwise quarantined at modest cost has been dug up and incinerated at great cost."[49]

The *Massachusetts v. EPA* case, in which the Supreme Court found that CO_2 was a pollutant and left the EPA to determine how it should be regulated, could affect the relationship of the Superfund program to CCS activities. If the EPA decides to control CO_2 as a hazardous air pollutant under Section 112 of the Clean Air Act, CO_2 then will meet the definition of a hazardous substance under CERCLA. The implication is that should a leak occur, the storage site owner, operator, and all others involved with the site, including those who sent CO2 for storage, potentially could be liable.

Superfund also provides that the federal government may respond in cases of "an imminent and substantial danger to the public health or welfare" caused by release of a "pollutant or contaminant." A pollutant or contaminant is defined very broadly and likely could include releases of CO_2 today, if they are deemed to pose an imminent and substantial danger.[50] The federal government may sue responsible parties to recoup costs incurred by the government for the response.

The terms "hazardous substance" and "pollutant and contaminant" in the CCS context must be considered not only with respect to CO_2, but also with respect to other constituencies in the injectate, even if present only in small concentrations. The terms also may be applicable to subsurface materials that mix with or are mobilized by the injectate. That is, Superfund potentially could apply in the CCS context regardless of whether CO_2 is considered to be a hazardous substance, pollutant or contaminant.

[49] *Not So Super Superfund*, NEW YORK TIMES (February 7, 1994) The Times continued: "Under Superfund's existing liability provisions, every company that dumped wastes into a Superfund site, at any point in the site's history, can be held responsible for the entire cleanup. This has encouraged companies to sue one another or their insurance carriers in an attempt to shift the blame and the cleanup costs elsewhere. The result has been interminable litigation that delays action."

[50] The term ``pollutant or contaminant'' includes "any element, substance, compound, or mixture, including disease-causing agents, which after release into the environment and upon exposure, ingestion, inhalation, or assimilation into any organism . . .will or may reasonably be anticipated to cause" death or physiological harm. 42 U.S.C. 9601(33).

CERCLA does not apply to a “federally permitted release,” pursuant to Section 107(j). However, the exception likely would not apply in cases where CO_2 accidentally has leaked from the storage site and caused damage.

CERCLA's federally permitted release exemption states that "recovery . . . for response costs . . . resulting from a federally permitted release shall be pursuant to existing law in lieu of [CERCLA]."[51] The section protects the holder of a federally approved permit from liability under the Superfund program for releases pursuant to the permit. A plaintiff’s response costs to a federally permitted release or any natural damages caused by the release may not be recovered under CERCLA; any recovery must be sought under State law or other applicable federal law which regulates the release. CERCLA Section 101(10) defines specific federally permitted releases as those regulated under permits issued pursuant to: the Clean Water Act (CWA);[52] the Resource Conservation and Recovery Act (RCRA);[53] the Marine Mammal Protection Act (MMPA);[54] Part C of the Safe Drinking Water Act (SDWA);[55] the Clean Air Act (CAA); and[56] the Atomic Energy Act (AEA).[57]

This exemption specifically covers “any injection of fluids authorized under Federal underground injection control programs or State programs submitted for Federal approval (and not disapproved by the Administrator of the Environmental Protection Agency) pursuant to part C of the Safe Drinking Water Act.”[58] With applicability to EOR, the exemption also specifically covers

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[51] 42 U.S.C § 9607(j) (2008).

[52] *Id.* § 9601(10)(A)-(D), (J) (2008).

[53] *Id.* § 9601(10)(E).

[54] *Id.* § 9601(10)(F).

[55] *Id.* § 9601(10)(G).

[56] *Id.* § 9601(10)(H).

[57] *Id.* § 9601(10)(K).

[58] *Id.* § 9601(10)(G).

any injection of fluids or other materials authorized under applicable State law (i) for the purpose of stimulating or treating wells for the production of crude oil, natural gas, or water, (ii) for the purpose of secondary, tertiary, or other enhanced recovery of crude oil or natural gas, or (iii) which are brought to the surface in conjunction with the production of crude oil or natural gas and which are reinjected. . . . .[59]

Thus, in the context of CCS or EOR, should CO_2 be deemed a hazardous substance and therefore subject to Superfund, parties would be exempted for a release of CO_2 permitted under the federal UIC program or an approved State UIC program. Should a release permitted pursuant to the UIC program require some remediation, costs of response would have to be recovered pursuant to the Safe Drinking Water Act, as discussed above, or common law.

The question arises whether accidental release of CO_2 from a permitted injection site would qualify for the federally permitted release exemption. The answer almost certainly is no. Both EPA and the courts have interpreted the federally permitted release exemption to apply to releases that are in compliance with a permit, but not to accidental releases.

Courts have narrowly interpreted the Section 107(j) exemption, reasoning that CERCLA specifically designated what releases where applicable under Section 101(10) and the detailed list indicates that Congress did not intend for non-listed releases to qualify as federally permitted and thus be exempt from the CERCLA liability scheme.[60]

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[59] *Id.* § 9601(10)(I).

[60] *See* United States v. Iron Mountain Mines, Inc., 812 F. Supp. 1528, 1540-41 (E.D. Cal. 1992) ("Congress considered the interplay between FWPCA and CERCLA when it enacted the latter statute, but declined to exempt municipal sewer authorities from its broad reach . . . FWPCA exemption extends to industrial discharges *into* POTWs, indicating that Congress specifically intended for CERCLA liability to reach releases *from* sewers or POTWs."); Reading Co. v. City of Philadelphia, 823 F. Supp. 1218, 1230-31 (E.D. Penn. 1993) (Toxic Substances Control Act (TSCA) compliance is insufficient to invoke the RCRA exemption under CERCLA); Westfarm Associates Ltd. Partnership v. International Fabicare Inst., 1993 U.S. Dist. LEXIS 19952 (D.Md. 1993). *See also* Idaho v. Bunker Hill Co., 635 F. Supp. 665, 673 (D. Idaho 1986); Reporting Exemptions for Federally Permitted Releases of Hazardous Substances, 53 Fed. Reg. 27,268-81, (1988) (to be codified at 40 C.F.R. §§ 117.12, 302.3, 302.6, 355)(proposed July 19, 1988).

For example, in *U.S. v. United Nuclear Corp*.,[61] the court rejected the argument of United Nuclear that seepage from uranium tailings ponds into groundwater was not part of the activity that was permitted, notwithstanding evidence that the State regulatory agency overseeing compliance with the permit knew the seepage was occurring. "The federally permitted release defense must fail because based on the four corners of the license this Court is unable to find any indication that the release of hazardous material was permitted. . . . Clearly there is no indication that the NMEID license was intended to permit seepage in unlimited quantities as United Nuclear would have this Court believe."[62]

In *Idaho v. Bunker Hill,* the court found that even where releases are federally permitted, CERCLA liability will apply "to the extent damage was caused by releases which were not expressly permitted in the various permits, which exceeded the limitations established by the permits or which occurred during a time period when there were no permits."[63] Costs of responding to a federally permitted release may be recovered if it is shown that non-federally permitted releases contributed to the natural injury at issue.[64] While plaintiffs have the burden of proving that a non-permitted release contributed to any damages, defendants must still prove that the injury is divisible if they wish to qualify any costs as attributable to a permitted release and thus unrecoverable.[65]

Further, EPA's own interpretation of specific federally permitted releases shows that EPA generally considers that accidental releases are not subject to the federally permitted release exemption. In most circumstances, releases resulting from accidents and malfunctions do not qualify for the federally permitted release exemption as defined in CERCLA section 101(10)(H).

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[61] 814 F. Supp. 1552 (D.N.M. 1992).

[62] *Id, at 1565.*

[63] Idaho v. Bunker Hill, 635 F. Supp. 665, 673-74 (D. Idaho 1986).

[64] *See* United States v. Iron Mountain Mines, Inc., 812 F. Supp. 1528, 1540 (E.D. Cal. 1992) citing See In re Acushnet River & New Bedford Harbor, 722 F. Supp. 893, 897 (D. Mass. 1989).

[65] *Id.*

Releases due to accidents and malfunctions, because they are by definition not anticipated, are difficult to subject to controls which limit or eliminate emissions. Congress did not intend to exempt unanticipated releases such as accidents and malfunctions from CERCLA section 103.[66]

Thus, an accidental release not in compliance with a permit would be subject to response costs and damages claims under Superfund in addition to the provisions of the Safe Drinking Water Act and State and common law.

The useful product exception, which exempts a party from liability under CERCLA Section 107, applies when a transaction constitutes conveyance of a useful product for a useful purpose, and is not an action to dispose of a hazardous substance.[67] In the seminal *Florida Power & Light Co. v. Allis Chalmers Corp.,* the 11th Circuit found that the mere sale of a hazardous substance or a product containing a hazardous substance cannot support a finding of liability "without additional evidence that the transaction includes an 'arrangement' for the ultimate disposal" or treatment of the hazardous substance.

Courts have implemented this approach across the Circuits. In *Freeman v. Glaxo Wellcome,* the Second Circuit found that defendant's sale of virgin chemicals at a discount before the closing of its facility was not considered an arrangement for the disposal of a hazardous substance because the chemicals were not waste at the time of sale.[68] In *Carter-Jones Lumber Co. v, Dixie Distributing Co.,* the Sixth Circuit affirmed the district court decision that circumstances surrounding the sale of PCB-contaminated transformers created the inference that the transaction was an arrangement for disposal not the sale of a useful product; thus the seller was liable under CERCLA.[69]

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[66] Guidance on the CERCLA Section 101(10)(H) Federally Permitted Release Definition for Certain Air Emissions, April 17, 2002, 67 Fed. Reg. 18899, at 18903.

[67] 893 F.2d 1313, 1317 (11th Cir. 1990).

[68]189 F.3d (2d Cir. 1999).

[69]166 F.3d 840 (6th Cir. 1999).

Professors Wilson and Klass note that “CERCLA typically does apply to hazardous substances contained in ‘useful products’ (as opposed to waste) which would mean that CERCLA might not cover stored CO_2 if it was classified as a ‘commodity’ rather than a waste.”[70] They later state that “there has been some effort . . . to encourage Congress, federal agencies, and states to classify CO_2 as a ‘commodity,’ thus avoiding a classification as a ‘waste’” but that this is unlikely to happen unless EPA changes the definition of solid waste to exclude CO_2.[71]

Personal and property damages are not recoverable under CERCLA. However, as discussed elsewhere within, plaintiffs may bring trespass, nuisance, or other common law actions for damages resulting from CCS facility leaks. Tort liability may be for remediation costs, diminution in value to property, lost profits, personal injury or other costs resulting from harm to human health or the environment.

If CCS is subject to CERCLA, plaintiffs in State common law cases may utilize any data generated from the remediation process pursuant to the development of remedial investigations or feasibility studies (RI/FS).[72] In addition, the statute of limitations in such common law cases is extended under CERCLA to the date that a plaintiff knew, or should have known that any alleged injury or damage was related to the contamination at issue.[73]

iii. EPCRA

The Emergency Planning and Community Right to Know Act of 1986 (EPCRA)[74] requires entities that emit “extremely hazardous substances” to report emissions greater than a

[70] Klass, A., and E.J. Wilson, *Climate Change and Carbon Sequestration: Assessing A Liability Regime for Long-Term Storage of Carbon Dioxide*, EMORY LAW REVIEW, forthcoming Fall 2008.

[71] *Id.* at 17.

[72] Gerrard, Michael, *Interaction of Toxic Tort and CERCLA Litigation*, TOXICS LAW REPORTER, (October 9, 1998) at 1.

[73] *Id.* at 3.

[74] 42 U.S.C. § 11001 et seq.

certain threshold amount. The purpose of this reporting is to encourage emitters by virtue of public disclosure to reduce emissions. The act establishes a local emergency response structure in the event of releases of such substances. Carbon dioxide is not listed as an extremely hazardous substance, and therefore CCS activities, at present, would not be subject to EPCRA reporting. The U.S. EPA has the authority to add substances to the reporting list through a notice and comment process.

The Pollution Prevention Act of 1990[75] was enacted to educate facilities about the benefits of pollution prevention control strategies. Under the authority of the Act, EPA develops and implements voluntary pollution prevention strategies targeted toward industry. The Act requires only facilities that file an annual toxic chemical release form under Section 313 of the Superfund Amendments and Reauthorization Act of 1986 (SARA), to include a toxic chemical source reduction and recycling report for the previous year, covering each toxic chemical reported in the SARA form.[76]

Since PPA programs are voluntary, any source reduction strategy promulgated by the EPA under the authority of the Act will not apply to a CCS facility unless it chooses to participate in the program.

iv. RCRA

The Resource Conservation and Recovery Act (RCRA) controls the disposal of "hazardous wastes." RCRA's requirements for treatment, transportation, storage, and disposal of a hazardous waste are very extensive and expensive.

Some are seeking to ensure that CO_2 is not viewed as a "waste," and that CCS activities are not viewed as waste disposal activities that would trigger RCRA or State statutes applying to waste disposal. RCRA defines a "solid waste" as, among other things, "discarded material,

[75] 42 U.S.C. § 13101.

[76] *Id.* § 13107.

including solid, liquid, semisolid, or contained gaseous material resulting from industrial . . . operations."[77] A "hazardous waste" is "a solid waste . . . which, because of its quantity, concentration, or physical, chemical, or infectious characteristics may . . . pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, or disposed of, or otherwise managed."[78] Hazardous wastes are either "listed" wastes (*i.e.*, wastes that EPA has specifically identified as hazardous); or "characteristic" wastes (*i.e.*, wastes considered to be hazardous because they meet the above definition and are ignitable, corrosive, reactive, or toxic). Notwithstanding the inappropriateness of applying RCRA's very complicated and costly regulatory regime to CCS, it is possible that RCRA's provisions could be interpreted to apply to underground storage of CO_2.

RCRA Subtitle C minutely regulates the generation, transportation, storage, and disposal of hazardous wastes in a manner too cumbersome for processes involving the volumes expected to be handled through CCS processes, especially given that CO_2 has low toxicity except if, upon release, it remains in very high concentrations. RCRA §3001 exempts other high-volume, low-toxicity wastes, including oil and gas production wastes, coal combustion byproducts, mining wastes, and cement kiln dust. An exemption for CCS seems appropriate, especially given that it will be regulated under another federal environmental program.

Pursuant to federal regulations, a UIC permit holder need not get a RCRA permit, but the applicability of RCRA and the interplay of the two programs are more complicated issues. To reduce permitting duplication and provide for both a hazardous waste permit and UIC permit (in the case of injecting hazardous wastes), regulations for RCRA's hazardous waste program grant UIC owners and operators a permit-by-rule (i.e., requiring the owner/operator to apply for only a UIC permit).[79] However, the UIC permittee still must meet certain RCRA requirements. So while a UIC permittee need not get a RCRA permit, the permittee still must assure compliance

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[77] 42 U.S.C. 6903(27).

[78] 42 U.S.C. 6903(5).

[79] 40 C.F.R. 270.60.

with RCRA provisions.[80] Therefore, having a UIC permit does not completely insulate a UIC permit holder from RCRA liability.

An additional RCRA issue is the citizen suit authority in Section 7002. This authority raises the specter that anti-coal activists could file suit for "contributing to the past or present handling, storage, treatment, transportation, or disposal of any solid or hazardous waste which may present an imminent and substantial endangerment to the health or the environment." It is unclear whether EPA could, via a UIC program regulation, prevent the filing of a citizen suit under RCRA.

v. Clean Air Act

For existing coal-fired facilities, a major question is whether the Clean Air Act, including the New Source Review (NSR) requirements of the Act, would apply if CCS equipment is installed.

NSR requirements are triggered by a physical change or change in method of operation that results in a significant net emissions increase. Installing carbon capture equipment would constitute a "physical change" under NSR. The next inquiry is whether the change would result in a significant net emissions increase. It could be argued that it might. For example, using amine scrubbers to capture CO_2 might result in an increase in particulate matter emissions from the plant (*e.g.,* perhaps small entrained droplets of absorbant). Carbon capture might require the heat input of the plant to increase - for example, to meet the load from running capture equipment or CO_2 compressors. This might cause emissions to increase from coal handling or, perhaps, stack emissions of collateral pollutants such as NOx.

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[80] 40 C.F.R. 270.60(b) provides for a permit by rule to "The owner or operator of an injection well disposing of hazardous waste, if the owner or operator: (1) Has a permit for underground injection issued under part 144 or 145; and (2) Complies with the conditions of that permit and the requirements of Sec. 144.14 (requirements for wells managing hazardous waste). (3) For UIC permits issued after November 8, 1984: (i) Complies with 40 CFR 264.101; and (ii) Where the UIC well is the only unit at a facility which requires a RCRA permit, complies with 40 CFR 270.14(d)."

For a long time, NSR requirements were interpreted so that the installation of pollution control equipment did not trigger compliance with NSR requirements. That interpretation no longer applies. As a result, installing Selective Catalytic Reducers (SCRs) on coal-fired power plants now regularly triggers the need for an NSR permit. SCRs reduce NOx emissions from a typical coal-fired power plant by hundreds of tons per year. However, SCRs generally result in a small increase in emissions of sulfuric acid mist. This characteristic of SCRs was not well understood until large SCRs were installed and emission profiles. This may be a cautionary tale for policy makers to consider with regard to CCS.

vi. Possible Implications of Greenhouse Gas Emissions Regulation

The regulation of greenhouse gas emissions under a possible cap-and-trade system could be used to create financial incentives for CCS projects. The scale of the incentives depends on how stored quantities of CO_2 are treated under the system, how emission allowances are allocated, and whether CCS projects are rewarded with additional, or "bonus," allowances or other types of financial assistance.

A possible cap-and-trade system would likely not consider CO_2 that is captured and permanently stored underground as part of a facility's emissions and therefore would not require that facility to surrender allowances to cover stored CO_2. In a cap-and-trade system where allowances are freely allocated to facilities based on historic levels of emissions, a facility that captures and stores its CO_2 emissions would be able to sell its unneeded allowances to help cover the costs associated with CCS. In a system where allowances are auctioned, a facility with CCS capabilities would still benefit financially, since it would not have to purchase allowances to cover its stored CO_2. For facilities with high levels of emissions, this could amount to not having to purchase millions of allowances per year.

The cap-and-trade regimes proposed over the past year in Congress include allocating allowances by auction, although most would freely allocate a limited amount of allowances in the early years of the program. While auctioning gives facilities that can store CO_2 emissions an advantage over facilities that lack CCS capability, it provides no new capital that could help cover the significant costs associated with the capture, transport, underground injection, and permanent storage of CO_2. As a result, most of the proposed cap-and-trade systems provide additional financial incentives for CCS, such as by awarding "bonus" allowances to eligible facilities that are able to capture and store CO_2 emissions. Some bills also provide that a portion of the auction revenues shall be used to encourage the demonstration and deployment of CCS technologies.

The Lieberman-Warner Climate Security Act of 2007,[81] reported out of the Senate's Environment and Public Works Committee in December 2007, proposed setting aside four percent of the allowances created each year from 2012 through 2030 in a bonus allowance account, which would then be distributed to eligible facilities that capture and store CO_2. The bill sets forth basic eligibility criteria and a formula for determining how many bonus allowances a facility should receive, based on a facility's annual emissions and how much CO_2 it is able to store successfully in a given year. The Substitute Amendment to the Lieberman-Warner Climate Security Act,[82] introduced by Senator Barbara Boxer during the June 2008 floor debate, retained the bonus allowance concept but reduced both the number of allowances in the bonus allowance account and the amount of bonus allowances a facility could receive under the formula. However, the Substitute Amendment also set aside one percent of auction revenues to fund, or "kick start," the deployment of CCS technologies. The kick start fund would be based on a proposal by the EPA's Advanced Coal Technology Work Group of the Clean Air Act Advisory Committee, which has since been included by Reps. Rick Boucher (D-VA) and Joe Barton (R-TX) in the Carbon Capture and Storage Early Deployment Act,[83] introduced in July 2008.

Among other proposed cap-and-trade bills, the Bingaman-Specter Low Carbon Economy Act[84] similarly provides for bonus allowances for CCS projects. However, bills proposed in the House have not yet adopted the bonus allowance concept. The Investing in Climate Action and

[81] S. 2191

[82] S. 3036

[83] H.R. 6258

[84] S. 1766

Protection Act, proposed by Rep. Ed Markey (D-MA), who is the chair of the House Select Committee on Energy Independence and Global Warming, uses 20 percent of the funds in its "Low-Carbon Technology Fund," which is established and supported by auction revenues, to fully fund the CCS-related provisions under section 963 of the Energy Policy Act of 2005[85] and section 703 of the Energy Independence and Security Act of 2007[86] in the years 2010-2013. The bill uses the remaining funds through 2020 to fund cost-sharing grants for eligible electric generating units that begin outfitting their plants with CCS technologies.[87] This is similar to what is being discussed in Europe for Phase III of the European Union Emission Trading System, which, like the Markey bill, would allocate virtually all allowances by auction and use auction proceeds to support demonstration and early deployment of CCS technologies.[88]

The creation of financial incentives for CCS through a cap and trade system hinges on not counting CO_2 that is permanently stored underground as part of a facility's emissions. This raises several emission reporting and accounting considerations that would need to be addressed either in the statute itself or through implementing regulations.

Most importantly, the scope and reach of the financial incentives are determined by how capture and permanent storage of CO_2 is defined. Many of the climate bills set forth performance-oriented criteria for CCS projects eligible to receive funding or bonus allowances. These criteria include the percentage of CO_2 captured at the source (*e.g.*, 85 percent of the CO_2 in a facility's flue gas, as well as emission performance standards). If such standards are too stringent, particularly in the early years of the program, the costs of the technology needed to meet those standards may be too high, even with bonus allowances and additional funding. This

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[85] 42 U.S.C. § 16293

[86] 42 U.S.C. § 17251

[87] H.R. 6186

[88] The "bonus allowance" concept also has been proposed in Europe, where facilities that use CCS would receive a bonus allowance for every ton of CO_2 stored. The proposal has received a mixed reception among policymakers. Note another recently proposed bill in the House, the Climate Market Action, Trust & Trade Emissions Reduction System Act of 2008 (Climate MATTERS Act, H.R. 6316), offered by Reps. Lloyd Doggett (D-TX), Earl Blumenauer (D-OR), and Chris Van Hollen (D-MD), did not include specific provisions regarding CCS.

is particularly true when the costs of fuel switching are taken into account, such as where it becomes cheaper for a facility to switch from coal to gas than to deploy CCS, even with bonus allowances and other funding.

B. State / Local

i. Property Rights In Geological Formations

Trespass risks underscore the importance of accumulating the necessary property rights prior to proceeding with any CCS project, possibly using unitization or eminent domain powers. Unitization is the joining of individual tracts into one common pool and is frequently used in conjunction with secondary oil recovery operations. Most oil-producing states require 50-85 percent of owners of a common oil pool to agree before unitization can occur. The exercise of eminent domain is a state or federal-level function, where the government can expropriate private property for projects designed to benefit the public.

The legal mechanism for securing property rights for CCS in many states may currently be ineffective. This will lead to costs and delays. It also may lead to tensions between large-scale CCS projects and individual property rights holders. Another threshold question, when one considers that this is harm that may occur far into the future, is whether the cause of action would be barred by either a statute of limitations (which begins to run upon the manifestation of the plaintiff’s injury) or, possibly, a statute of repose (that begins to run upon the conclusion of the defendant’s activities giving rise to the injury).

ii. Pore Space Ownership

Storage of CO_2 takes place in microscopic spaces ("pores") between grains in sedimentary rocks that were previously filled with brine or oil or gas. Injection of CO_2 for EOR purposes is currently considered part of the mineral lease operations and does not require the consent of the pore space owner. However, after the minerals have been extracted, ownership--and permission of the owner--may become an issue. The issue then becomes--who owns the pore space? Again, the rules vary significantly from State to State.

Except on federally-owned land, ownership of storage space is primarily determined under state law. The issue of ownership depends upon the type of geologic formation being considered.

There are two types of property interest relevant to determining ownership of the geologic storage formations (depleted oil or gas fields, deep coal seams or salt domes) and resolving liability issues -- the mineral interest and the surface interest. A majority of States apply the so-called "American Rule" which gives ownership of pore space, as distinct from the mineral estate, to the surface property owner. This rule has been applied by the courts, including in Louisiana, West Virginia and Michigan. A minority of states apply the so-called "English Rule," which holds that severance of the mineral estate grants ownership of the pore space to the mineral rights owner meaning that the owner of the mineral interest has ownership over the geologic formation, even after all the minerals have been removed. This rule has been applied by courts, including in Kentucky and Texas. It should be noted that even where the mineral interest owner has ownership over the subsurface formation, CCS operations may still require property interests over the land surface for drilling injection wells, pipelines to carry CO_2 to the formation, and necessary equipment such as compressor stations or monitoring devices.[89]

[89] Mark A. de Figueiredo, *Property Interests and Liability of Geologic Carbon Dioxide Storage*, MIT LABORATORY FOR ENERGY AND THE ENVIRONMENT, (September 2005) at 7.

The mineral interest concerns the right to explore and remove minerals from the land. This can include or be associated with a royalty interest, which involves the right to receive a share of the proceeds from the exploitation of the mineral resources. In most States, the mineral interest includes both stationary minerals such as coal as well as oil and gas resources. The surface interest includes all other ownership in the land. In most States, the owner of the surface interest also owns the geologic formation beneath it, including the saline formation.[90] The injection and storage of CO_2 in saline formations, as opposed to, for example, unmineable coal beds or depleted hydrocarbon reservoirs, raises questions over the ownership of the water contained in the saline formation, as some States rely on different legal and regulatory regimes to determine ownership over water resources. Water in saline formations is typically unusable, and most case law on point focuses on property rights over the taking and use of groundwater for consumption.[91]

The ownership of pore space in deep saline aquifers is even more complicated. The brine in deep aquifers is classified as "percolating water" (i.e. water that does not flow along a defined bed, like an underground river). Rivers and streams are the property of the state but ownership of percolating water depends on the applicable property regime followed in each state. There are at least five different property regimes -- Absolute Dominion, Reasonable Use, Correlative Rights, Restatement Rule, Prior Appropriation and combinations of these regimes. Where the American Rule is applied to the aquifer itself (i.e. the space that holds the percolating water), then ownership of the pore space is deemed to belong to the surface owner.

There does not appear to be any case law developed on ownership of pore space in deep coal seams (likely because CO_2 storage in such coal seams is not yet underway) and ownership of the space in salt domes would be more likely to follow the English Rule if the salt dome cavern were specifically developed for CO_2 storage.

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[90] Mark Anthony de Figueiredo, *Property Interests and Liability of Geologic Carbon Dioxide Storage*, MASSACHUSETTS INSTITUTE OF TECHNOLOGY CARBON SEQUESTRATION INITIATIVE (September 2005).

[91] *Id*.

iii. Liability for Trespass

Surface and subsurface trespass are two primary risks associated with the siting of CCS projects.[92] Surface trespass involves conducting site testing and monitoring and verification activities. Subsurface trespass involves underground migration of injected CO_2 into areas where property interests have not been acquired, as well as from waves shot for 3-D seismic mapping. It also involves the migration of displaced fluids or other underground materials into another's property

Commingling or "confusion" of goods represents yet another subsurface trespass concern relevant to CCS operations. Injected CO_2 potentially can migrate from the injection site to the subsurface area of an adjoining landowner. The operation of wells in compliance with permits will not necessarily insulate the operator from liability for trespass from adjacent subsurface owners. In several cases actions for subsurface trespass were allowed in connection with "fracturing" (hydraulic fracturing to increase permeability). Yet, other cases have applied the "negative rule of capture" to disallow nuisance suits associated with the migration of injected liquids, a rule that is widely accepted by legal scholars. This rule holds that, just as under the rule of capture a landowner may "capture" oil or gas that migrates under his land, a landowner can inject substances which "may migrate through the structure to the land of others."

Liability for confusion of goods occurs when different persons' goods are intermixed so that the property of each can no longer be distinguished.[93] An example might be the intermixing of injected CO_2 with native gas in a reservoir where the full property interests have not been obtained. Where substances are deemed willfully, fraudulently or wrongfully inseparably intermingled, the person forfeits his right in the goods to the innocent party. This would be determined on a case-by-case basis.

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[92] Elizabeth J. Wilson, *et al.*, *Liability and Financial Responsibility Frameworks for Carbon Capture and Sequestration*, WORLD RESOURCES INSTITUTE (December 2007).

[93] Strain v. Cities Service Gas Co., 83 P.2d 124, 126 (Kan. 1938)

Unitization rules frequently used for oil and gas development and in secondary oil recovery operations could be a useful tool to protect against trespass suits, particularly in large-scale CO_2 storage projects. An Alabama court reversed a $26.5 million award for draining of oil by an adjacent subsurface owner because the plaintiff had been given the opportunity to join the unitization and had turned it down. As noted above, most oil and gas producing States have "compulsory joinder of interest" for mineral extraction once a certain percentage (50-85%) of owners have agreed to field unitization. This approach is being widely considered for CO_2 storage.

iv. Ownership of Migrated CO2

The issue of who will own CO_2 that has migrated under the land of an adjoining subsurface owner may have an analogy in natural gas and oil precedents. The early courts applied the wild beast (*ferae naturae)* analogy to fugaceous oil and gas. This led to the "non-ownership" theory of oil and gas resources under which the subsurface owner did not possess the oil and gas until it had been captured. A court in Kentucky applied the non-ownership theory to gas that had been injected into a storage reservoir, but later cases rejected application of this rule to stored natural gas. Most States now follow the "ownership in place" theory, which gives the owner of the mineral rights a "possessory estate" to oil and gas injected into defined storage reservoirs. But the "rule of capture" continues to apply to gas that migrates under an adjoining landowner's property. A legal question arises as to whether the "rule of capture" analogy is appropriate for anthropogenic CO_2 (e.g. CO_2 captured from coal-to-gas or coal-to-liquids conversion) because that CO_2 was never "wild" (i.e. naturally occurring).

Where goods are intermingled (e.g. natural gas and CO_2 or CO_2 from one storage site commingled with CO_2 from an adjacent storage site), the ownership of the intermingled good will depend on being able to distinguish the goods. Courts have held that, where there was a fraudulent intent to commingle goods, the commingled good will be forfeited.

v. Nuisance Actions

Another potential private cause of action could be on grounds of nuisance where, as in the case of trespass, plaintiffs may include subsurface owners. The difference between a trespass and a nuisance claim is that a trespass claim involves actual intentional physical invasion of the plaintiff's property, while nuisance arises from the substantial interference of the use and enjoyment of the plaintiff's property.[94] Nuisance claims have been confronted in the subsurface injection context, for example, when salt water injected for secondary oil recovery contaminated a private drinking well.[95] In a CO_2 storage context, a nuisance claim might be that the injected CO_2 has migrated into a private groundwater supply and caused its carbonation, the carbonation having interfered with the use and enjoyment of the resource. This is usually remedied through an injunction, commanding or forbidding a party from taking an action, such as halting immediately continued subsurface injection operations, and/or payment of damages for the harmed property

vi. Negligence/Strict Liability Actions

Yet another potential cause of action would be a negligence cause of action, which cause comprises the bulk of tort litigation. Like trespass and nuisance causes of action, a negligence claim might address harm to property and the environment. In addition, it could be used to provide a recovery for the effects of CO_2 leakage on human health. Actionable negligence involves a legal duty on the part of a reasonably prudent person to use due care, a breach of such legal duty, and the breach as the proximate or legal cause of the resulting injury.[96] In a CO_2 storage contest, plaintiffs, to be successful, would have to show that the storage operator had a duty of reasonable care over the storage operation, that the operator breached that duty by his unreasonable conduct, and that harm was caused to the plaintiff as a result, such as damage to

[94] G. Nelson Smith III, *Nuisance and Trespass Claims in Environmental Litigation: Legislative Inaction and Common Law Confusion*, 36 Santa Clara L. Rev. 39,54 (1995).

[95] See, e.g., Gulf Oil Corp. v. Hughes, 371 P. 2d 81, 82 (Okla. 1962)

[96] Felburg v. Don Wilson Builders, 142 Cal. App. 3d 383, 393 (Cal Ct. App. 1983)

plaintiff's health, contamination of subsurface minerals, or harm to surface property. With respect to property claims, remedies could center on damage to the subsurface minerals or to property, such as diminution in value or costs of restoration.

There is the potential as well that CO_2 storage could be subject to strict liability, where the cause of action against the defendant is based upon an absolute duty to make something safe. It is different from negligence, however, in that a finding of strict liability does not depend on the level of care exercised by the defendant. If CO_2 storage were deemed to be "abnormally dangerous," plaintiffs, in order to recover damages, would only need to show harm and that a causal connection existed between the CO_2 storage and the injury. In other words, if strict liability were to apply, even the most careful and proper conduct by the site owner and operator still could result in liability in the case of an accidental release.

vii. Breach of Contract

Breach of contract raises special considerations with CCS projects, given the likelihood that CO_2 emissions will be the subject of future federal regulation, possibly as part of a cap-and-trade regime that places hard caps on greenhouse gas emissions. As discussed more fully above, a possible cap-and-trade system would likely not consider CO_2 that is captured and permanently stored underground as part of a facility's emissions, and as a result such facility would not be required to surrender allowances to cover those emissions. As parties contract to carry out the capture, transport, injection, and underground storage of CO_2, a key issue arising in such contracts is how they will address which party is liable for emissions from "failed" CCS projects, where CO_2 that is injected and stored underground ends up leaking into the atmosphere. A cap-and-trade system can address leaked CO_2 from failed projects in a variety of ways, such as by requiring the entity responsible for the leak to offset the leaked emissions through an offset project, or it could levy fines for non-compliance with emissions caps. Leaks from storage reservoirs containing CO_2 from multiple sources raises questions over attribution, since it is not possible to trace CO_2 back to an individual source once it enters the atmosphere. It should be noted that the entity responsible for the leak may not be the original emitter, such as in cases where an independent third-party oversaw the transport and injection of the CO_2 or where the leak occurs at a point in time where the state or federal government has assumed responsibility for the stored CO_2. Another consideration would involve a contract for the sale of "bonus" allowances awarded to a facility under a cap-and-trade system for carrying out CCS, which could be invalidated as a result of project failure. This could force the entity that purchases such bonus allowances into non-compliance with emission caps.

viii. Statutes of Limitation/Repose

A threshold issue for tortious liability for CCS storage, where the harm may occur far into the future, is whether the cause of action would be barred by a statute of limitations or, possibly, a statute of repose. The key difference between a statute of limitations and a statute of repose is that a statute of limitations begins to run upon the manifestation of the plaintiff's injury, whereas the statute of repose begins to run upon the conclusion of the defendant's activities that gave rise to the injury. Statutes of repose typically apply to a specific type of activity, such as the liability of an architect for a building intended to have an indefinite lifespan. Such statutes are, in effect, determinations by a legislature that not all injuries should be compensated. The statutes and are often justified on grounds of fairness to the potential defendant.[97]

ix. Eminent Domain

Intrastate States' eminent domain authority does not extend to acquisition of subsurface pore space for CO_2 storage. Nor is condemnation for natural gas storage generally allowed if the strata is still capable of producing oil in payable quantities or recoverable volumes of native gas has not yet been substantially depleted. This prohibition could present a problem for CO_2 storage in depleted oil and gas fields, since injection of CO_2 could in itself make "payable" quantities of natural gas recoverable (particularly if natural gas prices continue to rise).

The issue of condemnation or eminent domain authority over pore space needs to be considered to prevent unnecessary costs and delays. In one FutureGen site, the developer needed

[97] Mark Anthony de Figueiredo, *The Liability of Carbon Dioxide Storage*, MASSACHUSETTS INSTITUTE OF TECHNOLOGY, (February 2007) at 53.

to obtain agreements and easements from 69 rights holders. Seeking this many agreements could substantially increase the difficulty of storage. The difficulty likely will be magnified with CCS storage facilities, which, given the much greater volumes of carbon to be stored, are likely to result in injection plumes underneath far more surface property owners. Given a predicted injection plume of 40 square miles, one could envision hundreds or more surface owners whose agreement may be required. Widespread use of local and state eminent domain laws could present political concerns, especially given the public backlash against eminent domain driven by the U.S. Supreme Court in Kelo v. New London.[98] Moreover, the utilization of regional land use controls to ban large-scale CCS projects near valuable natural resources may be an obstacle to implementing projects in viable locations.[99]

x. Key State Statutes

Given that CCS is a technology that policy makers both at the State and federal levels want to encourage and because of the enormous societal benefit it may provide and the critical role that it could play to address climate change, State regulatory schemes should be expected to promote its construction and safe operation. This should include encouraging capital formation and the availability of risk management mechanisms. States are beginning to take some tentative steps but will need to do more to promote these technologies.

Kansas

On March 28, 2007, Kansas enacted the Carbon Dioxide Reduction Act, under which the Kansas Corporation Commission is to regulate existing and future CO_2 storage and to establish injection rules and regulations by July 1, 2008. The law provides that CCS property and any electric generation entity utilizing CCS shall be exempted from all property taxes for 5 years following completion of construction or installation of the property. The law also allows for

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[98] Kelo v. New London, 545 U.S. 469 (2005)

[99] Marianne Horinko, *Carbon Capture & Sequestration: Legal & Environmental Challenges Ahead*, AMERICAN PUBLIC POWER ASSOCIATION (August 2007).

accelerated depreciation of CCS equipment beginning in the 2008 tax year (55 percent the first year; 5 percent each of the subsequent 9 years) and all fees collected by the Kansas Corporation Commission are to be applied to a CO_2 storage fund.

Texas

The Texas Railroad Commission has proposed an amendment to its Oil and Gas regulations to implement House Bill 3732, which reduced the tax rate (a reduction of 50 percent) on oil produced as a result of enhanced oil or gas recovery using anthropogenic CO_2. The CO_2 must be sequestered in a reservoir that is productive of oil or gas and 99 percent of the CO_2 must remain sequestered for at least 1,000 years. The tax rate reduction applies until the later of 7 years or the date of a final rule by EPA regulating CO_2 as a pollutant.

Montana

A bill was introduced on May 27, 2008 for the purpose of specifying ownership of pore space and thereby providing protection and compensation for those who hold record title of the surface of the land below which is pore space used to store CO_2 or for other purposes (other than natural gas storage) and to affirm the dominance of mineral estates while allowing for the necessary development of pore space. In essence, this law would provides that ownership of all pore space below the surface vests with the owner of the surface land, and any conveyance of the surface ownership is also a conveyance of pore space below, unless previously severed and explicitly excluded from the conveyance. The law would not alter the common law relating to the "mineral estate" which means that the rights of the surface owner to mine, drill or re-complete a well, inject substances to facilitate production, or an enhanced recovery project or for other purposes are not affected. Transfers are void at the option of the transferor if the transfer does not contain a specific description of the pore space being transferred.

Washington

On May 3, 2007, a law was enacted requiring all baseload electric generation for which utilities in the State enter into future long-term financial contracts, to meet the State's emission performance standards. Generally, existing baseload facilities are grandfathered until they are upgraded or change ownership, and renewable energy facilities meeting certain criteria are exempt. Also exempt are facilities whose emissions are "injected permanently in geological formations" or "sequestered by other means." Facilities must submit a sequestration plan for review by the Department of Ecology and the Energy Site Evaluation Council and they will determine whether a facility's sequestration plan will provide "safe, reliable, and permanent protection" against greenhouse gas entering the atmosphere from the power plant and all ancillary facilities. A facility whose sequestration plan receives approval must make a good faith effort to implement the plan, and in the event implementation becomes unfeasible, the facility can then meet the EPA requirement through purchase of "verifiable greenhouse gas emissions reductions." The law will, on the whole, discourage upgrades that may increase power from existing units, or dispositions that trigger the requirement that existing baseload meet the greenhouse gas emissions performance standard. The state will need to be sensitive to whether the CCS regulations promote capital formation and availability of risk management mechanisms for CCS projects. On June 30, 2008, Washington adopted the nation's first state CCS injection rules, requiring that operators have a "high degree of confidence" that substantially 99 percent of the greenhouse gases will remain contained for at least 1,000 years." [100]

Wyoming

In March, 2008, carbon sequestration legislation was enacted that established that the ownership of all pore space is vested in the several owners of the surface estate. Therefore, a conveyance of the surface ownership represents a conveyance of the pore space -- unless the ownership interest has been previously severed. Agreements conveying mineral interests in real

[100] WAC 173-407-110.

property do not convey pore space ownership unless the agreement explicitly provides. The owner of any pore space right shall have not have the right to use the surface estate beyond what is set out in a properly recorded instrument. That said, the law does not alter the law of Wyoming regarding the primacy of the mineral estate (the right of a mineral owner or his lessee to reasonable use of the surface for the purpose of mineral exploration and production). The new law further prohibited the sequestration of CO_2 unless authorized by permit issued by the Department of Environmental Quality.

4. CCS Pipelines

A. Siting of CCS Pipelines

Siting of CO_2 pipelines is an issue that can have both federal and State dimensions, depending upon whether the pipeline crosses state borders. While there is no federal agency that currently issues permits for CO_2 pipelines for energy regulatory purposes, other agencies review linear facilities for effects on the environment, navigation, species, cultural and historic resources, and other issues. Issues related to pipeline approvals will need to be resolved to ensure that greatly expanded pipeline transmission of CO_2 for CCS can become available. To the extent that the system of CO_2 pipelines must evolve from shorter, stand-alone intrastate pipelines into a network of interconnected interstate pipelines, development of a coherent overarching regulatory structure that does not exist today, is necessary.

B. Interstate CO_2 Pipelines

An interstate pipeline constructed exclusively for transporting CO_2 and development of its rate structure falls within the regulatory jurisdiction of the U.S. Surface Transportation Board, an independent federal agency affiliated with the Department of Transportation.[101] However,

[101] Under the Interstate Commerce Commission Termination Act of 1995 (P.L. 104-880) the board regulates interstate pipelines transporting commodities other than water, oil or natural gas (49 U.S.C. Section 15301)

oversight by the STB is extremely limited as compared, for example, to federal regulation of natural gas and oil pipelines by the Federal Energy Regulatory Commission (FERC).[102]

Interstate CO_2 pipeline operators are free to set their own rates and service practices and there is no requirement that they file rates with the Board. Though the Board is tasked with ensuring that rates are reasonable and nondiscriminatory, it may only begin a rate proceeding or investigation in response to a complaint filed against a pipeline operator by a third party. Therefore, it may be difficult for regulators to ensure reasonable rate setting until after the pipelines are in service. Unlike the FERC, with respect to the pipelines it regulates, the STB has no regulatory authority with respect to CO_2 pipeline construction and has no eminent domain authority.[103] Therefore, any CO_2 pipeline whether interstate or intrastate, will today be regulated to varying degrees by the various States it traverses.

The State-by-State siting approval process for lengthy CO_2 pipelines could be complex and protracted and may face public opposition, especially in populated and environmentally sensitive areas. In the absence of consolidated oversight by, for example the FERC, or other regulatory authorities, fragmented permitting processes, non-standard permitting requirements and interagency redundancy can compound already existing siting challenges.

Much of this could change as the CO_2 pipeline network expands dramatically, with many more pipeline users and interconnections than exist today. Complex common carrier issues may arise. For example, should rates be set separately for existing pipelines carrying CO_2 as a valuable commercial commodity for EOR versus new pipelines carrying CO_2 as an industrial pollutant for disposal.

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[102] FERC ruled in 1979 that CO_2 pipelines are not subject to its jurisdiction because they do not transport natural gas for heating purposes. Cortez Pipeline Company, 7 FERC Para. 61,024 (1979).

[103] Companies seeking to build interstate natural gas pipelines must first obtain certificates of public convenience and necessity from the FERC pursuant to the Natural Gas Act. 15 U.S.C. Sections 717, et seq. Such certification also confers eminent domain authority.

C. Intrastate CO_2 Pipelines

Regulation of intrastate CO_2 pipelines in oil and gas producing states is connected to EOR operations and draws on analogies to oil and gas regulation, with CO_2 treated as a commodity and not as a "pollutant" or waste. Oil and gas producing States through their natural resources, oil and gas, and minerals commissions, generally provide eminent domain authority for CO_2 trunklines, but not for feeder lines, provide siting approval and apply siting requirements similar to those applied to oil and gas pipelines (*i.e.*, a certificate of public convenience and necessity is required from the relevant State regulatory agency).

D. The Question of Eminent Domain Authority

It is unclear whether CO_2 pipelines for CCS will be eligible to be granted the use of eminent domain authority to gain access to private property if necessary for construction, or whether agreements would need to be arranged with landowners on an individual basis. The latter could be a significant impediment to constructing CCS pipelines, as any individual landowner may be able to block construction of a needed pipeline.

The natural gas pipeline permitting process may provide a useful analog. Parties constructing interstate natural gas pipelines must obtain from the FERC a certificate of convenience and necessity, which carries with it the ability to exercise eminent domain authority, should an applicant be unable to arrange reasonable terms to cross a landowner's property.

It is not clear and it is an issue subject to State law, whether an entity constructing a CO_2 pipeline for CCS may obtain a certificate of convenience and necessity, and whether eminent domain authority would be available to construct such a facility. While CO_2 pipelines have been constructed for EOR and other purposes, there simply are no CO_2 pipelines in a pure CCS context, and so these issues have not been reached.

Were a CCS pipeline being constructed today with a desire to access eminent domain authority, there are several key questions to be considered, which again would be determined at present under State law:

1. *Who is applying?* Looking at State law that could be applicable, the type of company applying to build a CCS pipeline may affect the determination at the outset. Law pertaining to electric transmission facilities may provide some guidance. Kansas law, for example, considers any entity that transfers light and power for other than its own use to be a public utility, requiring certification. Certified entities have eminent domain authority. Thus it would appear that whether an entity has a service territory or simply generates power for others' use, the entity would have access to eminent domain authority.[104] In Arkansas, the authority is granted only to electric utilities with a service territory.[105] This is not only an issue of electric utility versus generation company, but also an issue for industrial facilities that may need to construct a CCS pipeline. It also may affect whether a utility or merchant generator decides to construct and operate its own pipeline or leave the pipeline construction, ownership and operation to an unaffiliated pipeline company. The State of Washington provides that

> Every corporation . . . doing business in this State, for the purpose of manufacturing or transmitting electric power, shall have the right to appropriate real estate and other property for right-of-way or for any corporate purpose. . . .[106]

Thus Washington provides for a very broad use of eminent domain authority.

2. *Is the facility needed to serve end-use customers in the State?* A standard consideration in determining whether a facility should be built is whether it is needed to

[104] Southwest Powerpool, *State Jurisdiction Question*, found *at* http://www.spp.org/publications/statejurisdictionquestion.pdf

[105] *Id*.

[106] RCW 80.32.060.

serve consumers in the State. A recent illustration of how States are considering this issue is the ongoing proceedings for the Trans-Allegheny Interstate Line. Virginia, West Virginia, and Pennsylvania have each held hearings to determine whether the line is needed to serve customers in the State. Missouri has considered the issue of whether service to end-use customers in the State is required in order to trigger the requirement to obtain a certificate of convenience. IES Utilities of Iowa required a certificate even though the facility being constructed would not serve end-use customers in the State.[107]

3. *What facilities are being constructed?* States limit the availability of eminent domain authority not only based on who is applying, but on what type of facility is being constructed. West Virginia, for example, provides that the public uses for which private property may be "taken or damaged" include (among others) "construction and maintenance of "telegraph, telephone, electric light, heat, and power plants, systems, lines, transmission lines, conduits, stations (including branch, spur and service lines) when for public use. . . ."[108] West Virginia's list does not appear to accommodate CCS pipelines. Thus, in at least some States, such pipelines would need to be added to State descriptions of facilities for which eminent domain authority can be used. Washington defines "associated facilities" to include "storage, transmission, handling, or other related and supporting facilities connecting an energy plant with the existing energy supply, processing, or distribution system. . . ."[109] This definition seems to provide some latitude by which CCS pipelines might be included.

4. *Is the facility to have a public use?* The West Virginia statute raises an additional issue, which is whether the facility is for public use. Depending on the specifics of State law and its interpretation, this may mean that regulators would consider whether the pipeline is a common carrier pipeline or to be used only for one facility.

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[107] Southwest Powerpool, *State Jurisdiction Question*, found *at* http://www.spp.org/publications/statejurisdictionquestion.pdf

[108] W. Va. Code § 54-1-2(a)(2).

[109] RCW 80.50.020.

One way to address eminent domain issues for CCS pipelines would be to provide in federal law that such facilities are eligible for a federal certification, akin to that under Section 7 of the Natural Gas Act[110] for natural gas pipelines, that would carry with it eminent domain authority.

Congress recently provided FERC with "backstop" siting authority, and with it eminent domain authority, in limited cases through a provision in the Energy Policy Act of 2005.[111] Pipelines that would be constructed for CCS purposes are a classic case of facilities built for the public good and for which the exercise of eminent domain authority would be appropriate.

E. CO_2 Pipelines On Federal Lands

New CO_2 pipelines that pass through federal lands managed by the Bureau of Land Management (BLM) potentially may be sited under right-of-way provisions in either the Federal Land Policy Act (FLPMA)[112] or the Mineral Leasing Act (MLA).[113] The MLA imposes a "common carrier" requirement while the FLPMA does not. That said, the MLA currently permits CO_2 pipelines for EOR under the MLA. Today, the BLM permits CO_2 pipelines for EOR in a manner that implicitly treats CO_2 as a "commodity" and not as a "pollutant." However, BLM permitting of CO_2 pipelines for non-EOR purposes may necessitate a statutory change to require common carriage. Also, renegotiation of expiring pipelines rights-of-way across Indian lands is becoming increasingly difficult, with tribes demanding significant concessions. Federal eminent domain powers are typically not applicable on such lands. Section 368 of the Energy Policy Act of 2005 directs various federal departments to coordinate the designation of corridors for certain energy-related facilities across federal lands. CO_2 pipelines

[110] 15 U.S.C. 717f.

[111] Section 1221 of the Energy Policy Act of 2005 (codified as Section 216 of the Federal Power Act).

[112] 43 U.S.C. Section 35

[113] 30 U.S.C. Section 185

are not explicitly covered, though they could make use of corridors designated for other energy infrastructure.

F. Application of Other Federal and State Statutes Triggered by Siting of the Facility

At the federal level, the siting of linear facilities most often raises issues under the Clean Water Act, the Rivers and Harbors Act of 1899, the National Environmental Policy Act, and the Endangered Species Act. Any number of other federal statutes may apply, depending upon the resources affected by or near the facility.

i. Clean Water Act; Rivers and Harbor Act of 1899

Facilities that impact waters of the Unites States may require permits from the Army Corps of Engineers under Section 10 of the Rivers and Harbors Act of 1899,[114] Section 404 of the Clean Water Act,[115] or both. The Rivers and Harbors Act is intended to prevent obstructions to true navigable waters, and permits are generally granted upon meeting certain public interest criteria. The Clean Water Act covers all waters of the United States, which includes not only navigable waters but also non-navigable tributaries and adjacent wetlands. Clean Water Act permits are granted based on more stringent criteria, such as a showing of no significant degradation, and carry a duty to mitigate unavoidable impacts.

The Army Corps of Engineers issues two types of permits, individual and general, under both the Rivers and Harbors Act and the Clean Water Act. General permits are often used for pipeline or transmission line projects whose estimated impacts on waterways do not exceed a half-acre. General permits are issued by the Corps on a national scale and reevaluated every five years, at which time a cumulative NEPA analysis is performed. As a result, NEPA requirements do not apply for each individual pipeline or transmission line project that is eligible for a general

[114] 33 U.S.C. 403.

[115] 33 U.S.C. 1344.

permit. However, Endangered Species Act requirements still apply. Typically, the Army Corps of Engineers issues joint permits when a facility requires them under both statutes.

ii. National Environmental Policy Act

Most pipelines of any length are likely to require a federal permit of some sort, which is likely to provide the significant federal involvement in the project that acts as the trigger for application of the National Environmental Policy Act (NEPA).[116] Where NEPA applies, the act often requires extensive evaluation of the environmental, historical, cultural and socio-economic impacts arising from "major federal actions significantly affecting the quality of the human environment." Permits for significant projects often require Environmental Impact Statements (EIS), the most thorough procedural review under NEPA, which can take years and cost millions of dollars to complete. For example, the average time for the Federal Highway Administration to complete an EIS between 1995 and 2001 was 5.1 years.[117] In cases of projects likely to have less significant impacts, an agency will perform a less rigorous Environmental Assessment (EA), which often will result in a Finding of No Significant Impact. Other federal actions not likely to have a significant impact are subject to a categorical exclusion. Such NEPA reviews, which are a procedural rather than a substantive hurdle, are commonly the subject of protracted litigation sponsored by groups seeking to halt or alter such projects.

Federal funding of CCS projects may trigger NEPA review. Federally-sponsored CCS demonstration projects are complying now. DOE is currently pursuing a programmatic EIS to assess the potential environmental impacts of its entire Carbon Sequestration Program.

If pipelines cross public lands, they are generally required to obtain right-of-way easements for areas under the jurisdiction of the Bureau of Land Management, Bureau of Reclamation, and the United States Forest Service. Granting of such easements is likely implicate NEPA and other environmental reviews. It should be noted that PHMSA's pipeline

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[116] 42 U.S.C. 4321 et seq.

[117] Kreig Larson, *The Road to Streamlining: An In Depth Look at the NEPA Process and Ways to Expedite It*, PUBLIC ROADS, (July-August 2003).

rate regulation, described above, does not trigger a review of environmental impacts under NEPA. State environmental statutes modeled after NEPA potentially also could be triggered if a CO_2 pipeline is built in conjunction with a new power plant.

iii. Endangered Species Act

The Endangered Species Act (ESA) directs federal agencies to ensure that their actions do not jeopardize endangered or threatened species or destroy or adversely modify critical habitat.[118] Federal permits implicating the ESA can require consultation with the U.S. Fish and Wildlife Service or the National Marine Fisheries Service to determine potential impacts on any listed species. This can take the form of a biological opinion rendered by one of the agencies. If impacts are shown, an Incidental Take Statement can be granted as a kind of limited exemption.

Even when there is no federal permit involved, the ESA bars actions that result in harm or harassment to listed species. In these instances, Incidental Take Permits are available, but generally take longer to obtain than Incidental Take Statements.

5. Legal Issues Surrounding Carbon Sequestration Beneath the Ocean Floor

Increasing attention is being given to the use of sub-seabed geological formations such as offshore oil and gas reservoirs and deep saline formations to store CO_2. CO_2 storage off-shore may pose a lesser likelihood of harm because of the lack humans living near the operations. This option is shaping up to be one of the most feasible near-term options for managing CO_2 emissions. However, CO_2 storage conducted offshore would be impacted by international law though the issue has not yet been directly and specifically addressed in any relevant multilateral environmental agreement that is currently in force.

Of particular relevance would be the United Nations Convention on the Law of the Sea (UNCLOS), to which the U.S. is not a party, which sets forth boundaries within which states

[118] 16 U.S.C. 1531 et seq.

have certain rights. If the U.S. were ultimately to join the Convention, as now seems likely, it would not be prohibited from engaging in sub-seabed CO_2 storage within its territorial sea, which extends twelve miles form the coast.

Beyond the territorial sea, UNCLOS has two sets of provisions governing the seabed and subsoil. UNCLOS defines a coastal state's "continental shelf" as comprising the seabed and subsoil extending from the boundary of the territorial sea to 200 miles from shore. States have "sovereign rights" under the convention to explore and exploit the natural resources of their continental shelf, including the mineral and other non-living resources of the seabed. The second set of provisions defines a coastal state's "exclusive economic zone," (EEZ) a 200-mile zone beyond its territorial sea within which a state has "sovereign rights for the purpose of exploring and exploiting, conserving and managing" living and non-living natural resources of the seabed and its subsoil. It would seem that under both the EEZ and continental shelf definitions of sovereign rights, CO_2 injection associated with EOR would be permitted as a form of exploiting natural resources. The legality of other methods, such as the injection of CO_2 into deep saline formations, is more uncertain and depends upon whether such a geological formation for CO_2 storage is considered a non-living resource. The issue becomes whether the state has a sovereign right over the pore space of the geological formation that would contain the CO_2.[119]

The 1972 London Convention, to which the United States is a party, establishes a legal regime for the dumping of wastes or other matter and provides a minimum set of global rules and standards for compliance under the UNCLOS. The London Convention has established a working group to consider specific issues related to CO_2 storage and determine the consistency of CO2 storage with the Convention. The Secretariat of the London Convention is on record that storage of CO_2 in geological structures under the seabed is not covered under the Convention.

The 1996 London Protocol superseded the London Convention when it entered into force on March 24, 2006, though the U.S. is not a party and continues to be bound by the London Convention. The London Protocol defines dumping to include "the storage of wastes or other

[119] Mark Anthony de Figueiredo, *The Liability of Carbon Dioxide Storage*, MASSACHUSETTS INSTITUTE OF TECHNOLOGY, February 2007.

matter in the seabed and the subsoil thereof from vessels, aircraft, platforms or other man-made structures at sea."[120] Though the Protocol was not negotiated with CO_2 storage in mind, it appears on its face to govern sub-seabed storage. Significantly, at the first meeting of the Contracting Parties to the London Protocol, the parties agreed to amend the Protocol to permit sub-seabed CO_2 storage.[121] The amendments, which entered into force in February, 2007, state that carbon dioxide streams may only be considered for dumping if disposal is into a sub-seabed geological formation, they consist overwhelmingly of CO_2, and no wastes or other matter have been added for purposes of disposal.

The legal status of CO_2 storage under the UNCLOS, the London Convention and its Protocols, has not yet been fully determined though that determination will be central to the future of sub-seabed storage as a U.S. carbon management strategy. If there is ambiguity as to whether sub-seabed CO_2 storage would be permissible under international law, as there is today, because these agreements were not negotiated with CO_2 storage in mind, countries such as the United States might choose not to pursue it and pursue on-shore storage instead, particularly when they have large on-shore capacity. Therefore, further clarification will need to be sought at the Conferences of the Parties of the applicable marine agreements, even though some uncertainties have become more clear with the recent passage of amendments to the London Protocol.

[120] London Protocol, Art. 1 Section 4

[121] International Maritime Organization, *IMO Briefing: New International Rules to Allow Storage of CO_2 in Seabed Adopted* (Briefing 43/2-006, Nov. 8, 2006)

6. Long-Term Liability

Engineered and natural analogues to the underground injection and long-term storage of CO_2 suggest that it can be safely and effectively achieved at a large-scale, provided best practices are adhered to for well drilling and injection. The appropriate selection of a geologic storage site based on available subsurface information and use of a monitoring and remediation program to detect and address any potential release of CO_2 render the risks to human health and the environment comparable to current activities such as natural gas storage, EOR/EGR, and deep underground disposal of acid gas.[122]

From a regulatory and policy perspective, the virtually indefinite timeframe in which CO_2 would need to be contained underground raises questions over who should be responsible for post-closure monitoring and who would be subject to liability in the event of an accident. In some cases, the project developer and/or operator may no longer exist, making it necessary to consider liability transfers to the state once a CCS cite has ceased operation. Additionally, financing and securing insurance for a CCS project depends on clear definitions of liability, in order to calculate costs and risks associated with a project.

State government could be asked to grant indemnity for CCS-related activities. For example, the state governments of Texas and Illinois agreed to take title to the injected CO_2 and indemnified the FutureGen Industrial Alliance and its members from any potential liability associated with the CO_2.[123]

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[122] *Special Report on Carbon Dioxide Capture and Storage*, INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE (2005), at 12.

[123] *See* Texas Natural Resources Code §§ 119.002(a) and 119.004(b)-(c) ("The [Texas Railroad] commission shall acquire title to carbon dioxide captured by a clean coal project. … [T]he owner or operator of the clean coal project is relieved from liability for any act or omission regarding the carbon dioxide injection, if the injection location and method or means of injection comply with the terms of a license or permit issued by the state and applicable state law and regulation. … [N]o owner, operator, or contractor of the clean coal project is immune from liability for personal injury or death that results from construction of the site, or drilling or operation of the injection wells."). *See also* Illinois Public Act 095-0018 (" … [T]he FutureGen Alliance agrees that the Operator shall transfer and convey and the State of Illinois shall accept and receive, with no payment due from the State of Illinois, all rights, title, and interest in and to and any liabilities associated with the sequestered gas … . Notwithstanding any law to the contrary, the State of Illinois shall indemnify, hold harmless, defend, and release the Operator from and against any public liability action asserted against the Operator … . In the event that any public

At the federal level, one model for long-term indemnity is the Price-Anderson Act, which establishes a no-fault insurance program designed to indemnify the nuclear industry against liability arising from accidents.[124] The Act caps accident liability at $7 billion (approximately $10 billion in nominal terms as of 2006), with three tiers of responsibility. Tier 1 requires individual nuclear plant operators to obtain primary insurance coverage up to a mandated level (as of 2005, $300 million per plant). Tier 2 requires that each company contribute up to a statutory cap of $95.8 million per reactor owned, with payments made by each company in the event of an accident capped at $15 million per year until claims are met or the maximum individual liability has been reached. Tier 3 requires the federal government to backstop the remaining balance owned to claimants, once the caps are reached.

There are a number of liability protection legislative schemes that might also provide useful concepts or ideas in the CCS liability context. The National Flood Insurance Program (NFIP) offers another mode of protecting CCS project developers and operators against losses in the event the underground reservoir fails to contain the stored CO_2.[125] It also illustrates some underlying concerns and issues that can arise from federally-funded insurance schemes. NFIP was created by Congress in 1968 through the National Flood Insurance Act of 1968, which enables property owners to purchase insurance against losses from flooding. The insurance is intended to provide an alternative source of compensation to disaster assistance. Participation in the NFIP is based on an agreement between local communities and the federal government, whereby flood insurance is available for residents whose communities adopt a floodplain management program that would minimize risks of damage to buildings in flood-prone areas, known as Special Flood Hazard Areas. NFIP has been amended several times, including most recently by the Flood Insurance Reform Act of 2004, to address criticism arising from findings

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liability action covered under Section 30 of this Act is commenced against the Operator, the Attorney General shall, upon timely and appropriate notice to the Attorney General by the Operator, appear on behalf of the Operator and defend the Action.”).

[124] Other models include the Uranium Mill Tailings program and the Trans-Alaska Pipeline fund, as well as the MTBE program and Federal Flood Insurance program.

[125] Pub. L. 90-448.

that repetitive-loss properties were costing taxpayers approximately $200 million annually. In effect, NFIP was providing people with an incentive to move to flood-prone areas, as they knew that any losses suffered from flooding could be recouped through NFIP coverage. Indeed, NFIP was criticized as increasing the likelihood that flood-prone areas would be occupied by people and structures least able to withstand and recover from flood disasters. If an NFIP-like program were to be adapted to help cover the risks associated with CCS, it would be necessary to ensure that appropriate safeguards were in place to ensure that CCS projects were developed and operated according to best practices.

The Terrorism Risk Insurance Act (TRIA)[126] creates federally-backed support on insurance claims arising from acts of terrorism. Among other things, the Act establishes a program within the Treasury Department whereby the federal government would share the risk of loss from future terrorist attacks. To trigger this program, insurers must first pay a certain amount in claims arising from an event certified by the Treasury Secretary as an act of terrorism before federal assistance becomes available, at which point the government covers additional losses up to a certain percentage (e.g., 90 percent) and the insurer covers the balance. Losses covered by the program are capped at $100 billion, and the government can recoup the amounts paid via a surcharge on policyholders. The Act was developed in the aftermath of the events of 9/11 to establish a temporary federal program that provides for a transparent system of shared public and private compensation for insured losses resulting from acts of terrorism and provide the insurance industry with time to develop new strategies and products to insure against terrorist acts. The Act was set to expire in 2005, but has been extended twice, to 2008 and, most recently, 2015 by the Terrorism Risk Insurance Program Reauthorization Extension Act of 2007.

Other examples of federal liability protection include Section 162 of the Amtrak Reform and Accountability Act of 1997, which restricts the amount of punitive damages that can be recovered from rail-related accidents resulting in loss of life or damage to property.[127] Specifically, the Act states that punitive damages may be awarded only if a plaintiff can show

[126] Pub. L. No. 107-297.

[127] Pub. L. No. 110-160.

that the harm arose as the result of the defendant's conscious, flagrant indifference to the rights or safety of others and sets a ceiling on aggregate allowable awards for all claims arising from a single accident or incident at $200,000,000. There also is the Biomaterials Access Assurance Act of 1998, which limited the liability of plastics manufacturers, suppliers, and sellers dealing in specialty plastics needed to make biomechanical devices for use inside the human body.[128] The Act seeks to prevent plastics manufacturers, suppliers, and sellers from being included in medical malpractice suits against doctors and hospitals except in cases where they failed to adhere to product specifications or if the suit involved breach of contract.

The UIC program mitigates risk to the public by setting forth criteria for financial assurance requirements. Operators of certain wells under UIC programs must demonstrate that they have adequate financial resources to close and abandon their injection wells if they cease operation, with the amount required a function of the estimated costs of plugging and abandoning the injection well. Generally, a financial assurance requirement is designed to create incentives for project developers and operators both to undertake CCS projects despite potentially prohibitive risks of long-term post-closure management and to design, site, and operate facilities in a manner that minimizes risk of injury to public health and the environment. Federal UIC regulations do not address post-closure periods. At the State level, the period of responsibility post-closure typically runs for 30 years, depending on the type of well.

These examples and others demonstrate that where there have been activities or services deemed to be in the public interest that carry with them risks too great for the private sector to bear alone, the federal government has stepped in to ensure that they are carried out. The importance of ensuring a secure energy supply for America and the likelihood that CO_2 emissions will be included in efforts by Congress to address climate change indicate that commercial-scale deployment of CCS technologies will be imperative in the coming years. At present, uncertainty over long-term liability issues associated with the underground storage of CO_2 has deterred project developers, financiers, and insurers from moving forward with CCS. CCS can reduce CO_2 emissions associated with power generation and permit long-term use of secure and affordable sources of energy. Accordingly, CCS represents a vital public interest that

[128] 21 U.S.C. §§ 1601-06.

merits a federal-level program to clarify and resolve long-term liability issues and clear the way for the rapid and widespread commercialization of the technology.

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This study should be viewed as an iterative document and may be updated periodically.