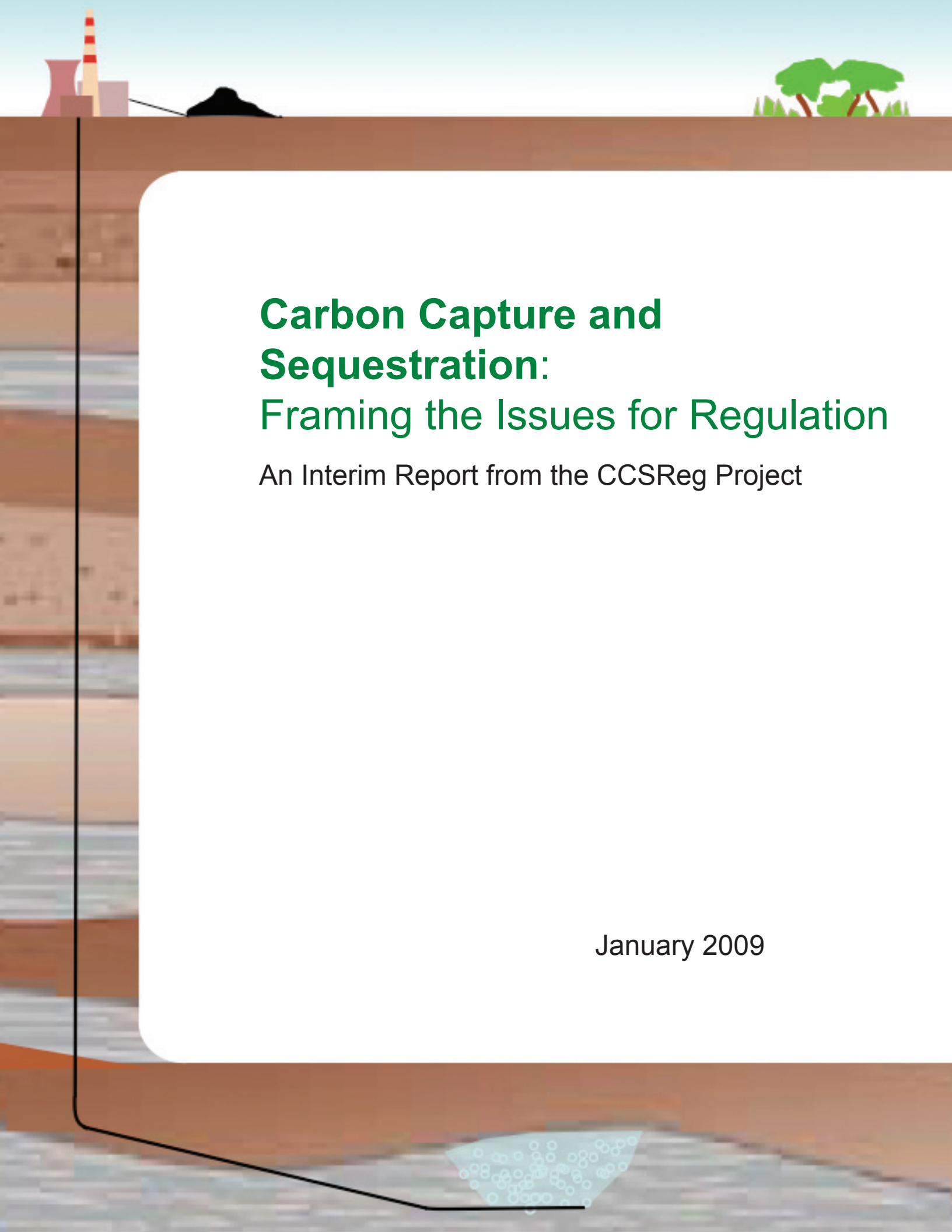




Carbon Capture and Sequestration: Framing the Issues for Regulation

An Interim Report from the CCSReg Project

January 2009

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About the CCSReg Project

The CCSReg Project is an interdisciplinary project which aims to design and facilitate the rapid adoption of a U.S. regulatory environment for the capture, transport and geological sequestration of carbon dioxide. Our objective is to assure that CCS will be done in a manner that is safe, environmentally sound, affordable, compatible with evolving international carbon control regimes (including emissions trading) and socially equitable.

The project is anchored in the Department of Engineering and Public Policy at Carnegie Mellon University. Other members of the project team are located at the Hubert H. Humphrey Institute of Public Affairs at the University of Minnesota, the Institute for Energy and the Environment at the Vermont Law School, and the Washington, DC law firm of Van Ness Feldman.

This project was made possible through support from the Doris Duke Charitable Foundation (Grant 2007117) to Carnegie Mellon University, Department of Engineering and Public Policy for the project, “Regulation of Capture and Deep Geological Sequestration of Carbon Dioxide.” Additional funding for some analyses is provided by the National Science Foundation (SES-0345798) through the Climate Decision Making Center and the Carnegie Mellon Electricity Industry Center.

More information on the CCSReg Project is available at: <http://www.CCSReg.org/>

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Executive Summary

When fossil fuel (coal, oil and gas) is burned, much of the CO₂ that is produced stays in the atmosphere for over 100 years. In order to stabilize the atmospheric concentration of CO₂, we must reduce emissions approximately 80% from current levels, otherwise the atmospheric concentration of CO₂ will continue to grow. While renewable and other low-carbon energy technology will help, for at least the next half century we will also have to continue to use fossil fuel. Fortunately, there is technology that will allow us to capture the CO₂ before it is released, and “sequester” it permanently several thousand feet or more underground in appropriate geological formations. This process is called “carbon capture and sequestration” or CCS.

CCSReg is an interdisciplinary project to develop recommendations for how best to regulate the process of capturing CO₂, transport it in pipelines, and sequester it safely and securely in appropriate deep geological formations. The project is anchored in the Department of Engineering and Public Policy at Carnegie Mellon, and involves co-investigators at the Institute for Energy and the Environment at the Vermont Law School, the Hubert H. Humphrey Institute of Public Affairs at the University of Minnesota, and the Washington, D.C. law firm of Van Ness Feldman. A list of project investigators is provided on page ii of the report.

This interim report is not designed to provide answers. Rather it frames the issues that the CCSReg project team believes must be considered if CCS is to be safely and effectively developed. We begin with only two basic assumptions:

- Before finalizing a U.S. regulatory framework to govern the operation of CCS, it will be important to gain substantial experience with a number of commercial-scale projects. Until that time, existing regulations, perhaps augmented by those now under development by EPA, should be sufficient to allow initial large-scale CCS projects to go forward. We term this strategy of learning from field experience a “two-stage” approach to regulation.
- Because it will be impossible to know with certainty the specific behavior of large volumes of CO₂ injected at great depth before injection begins, an effective regulatory approach must involve an adaptive, performance-based approach for any given project. Rather than a strict requirement to spell out everything in precise detail before injection begins, project risks should be adaptively managed as projection proceeds and field experience yields more insight about the specific geological formation that is being used.

A number of technologies now exist at commercial scale, that, when combined, will make

it possible to apply CO₂ capture to large power plants and various other industrial facilities, and may allow CO₂ to be directly removed from the air. These are briefly discussed in Chapter 2. Issues of regulation and liability that may arise for CO₂ capture facilities appear to be similar to those that occur with any large industrial facility.

Once CO₂ has been captured it must be transported to an appropriate injection site. For onshore injection sites, CO₂ will be transported via pipeline. Chapter 3 notes that the current Federal regulatory framework for CO₂ pipeline rate and access regulation can only be described as Byzantine. The Federal Energy Regulatory Commission (FERC) has disclaimed jurisdiction over CO₂ pipelines under the Natural Gas Act. The Surface Transportation Board (STB) has taken no position on whether it has jurisdiction over CO₂ pipelines, although its predecessor, the ICC, disclaimed jurisdiction. The Bureau of Land Management (BLM) has imposed the equivalent of a common carrier obligation on CO₂ pipelines crossing Federal lands. Pipeline safety is clearly regulated under the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA).

Large-scale commercial deployment of CCS will likely require a large build out of CO₂ pipeline infrastructure. This, in turn, will require substantial changes in CO₂ pipeline regulation. In particular, it seems unlikely that reliance on state-by-state siting processes and eminent domain authority will be sufficient to support construction of a network of interstate CO₂ pipelines that could approach the size of the current natural gas pipeline system.

Today, in most of the U.S., it is unclear who—if anyone—owns the right to inject CO₂ into deep underground pore space. The concept that landowners own everything from the surface of the earth up to the heavens and down to the center of the globe is more a convenient metaphor than a legal reality, and has already been eroded by legal decisions involving over-flight by airplanes. Most projects that inject waste fluids under the EPA underground injection control (UIC) program have *not* secured permission from surface property owners. In many cases, the volume of injection by UIC-permitted wells are small, but injections of waste fluids by the oil and gas industry can be comparable in volume to CCS projects. Similarly, wastewater treatment facilities in southern Florida inject over three billion tones per year of treated wastewater into underground formations without approval or authorization from surface property owners. In Chapter 5, we lay out and discuss a range of ways in which the right to access and use deep pore space might be resolved. Several possible outcomes could make it infeasible to implement large commercially viable CCS projects.

“An inverse rule of capture,” which appears to be the way in which most waste injection is now operating, could be formalized by state or Federal law. Such legislation would then likely be tested in the courts, and if implemented state-by-state, could result in a patchwork of different outcomes in different states. New law could also specify some

form of compensation for the use of pore space to surface property holders at levels that might or might not be considered *de minimis*. Alternatively, state or Federal legislation could give government the authority to assign rights to access and use deep pore space for CCS. Whether it would be politically feasible for the U.S. Congress to implement such an arrangement at a Federal level is unclear. However, such a single national solution would obviate the problems that might arise when receiving reservoirs involve more than one state, and could also lead to more orderly and simplified project development and limit issues that might later arise as sequestered CO₂ enters into international trading or other carbon control regimes.

The U.S. EPA has recently promulgated draft regulations for CO₂ underground injection. Unfortunately, because it has done this under the limited authorization provided by the Safe Drinking Water Act (SDWA), EPA's draft rules do not address the issues of legal access to pore space, and safe and secure long-term stewardship of a sequestration site once a reservoir has been filled to capacity. Moreover, while protecting underground sources of drinking water (USDWs) is an essential environmental goal, avoiding the dangerous impacts of climate change is also critically important.

Chapter 6 discusses both the EPA Class VI proposal and several other approaches that might be adopted including a new free-standing legislative framework for addressing CCS. The chapter also identifies a variety of mechanisms to balance the (potentially conflicting) national environmental interests in protecting USDWs and minimizing the release of CO₂ to the atmosphere. The chapter notes that a two-stage approach could be pursued, in which the UIC program continues to permit wells injecting CO₂ for a set period of time, but new legislation establishes a commission charged with gathering results from pilot projects and providing recommendations to Congress on the form for regulation of widespread commercial CCS.

Chapter 7 turns to a discussion of long-term stewardship. Options include a private solution (akin to that used in the UIC today), a solution in which site becomes the responsibility of the state in which they are located, a solution in which a closed site becomes the responsibility of a Federal entity, and a hybrid private-public solution. It argues that to minimize potential conflict of interest, if a government entity assumes responsibility, it should not be the same entity as that responsible for the regulation of site operation. The chapter also includes a discussion of issues of certification of sequestered CO₂ for national and international emission trading markets.

There has been a great deal of confused discussion about liability in connection with CCS. Chapter 8 lays out a range of alternative approaches to addressing tort liability, noting that liability during site operation can be adequately addressed via conventional insurance and similar methods. If long term stewardship is handled by a government agency, then liability would also be assumed by that agency, although the project entity should remain liable for conditions that pre-date the hand-off for long-term stewardship.

The final chapters address a number of more general issues. Chapter 9 discusses a number of the broader issues that must be addressed if a business environment is to be created that encourages the development of CCS projects. Chapter 10 explores CCS in the context of a variety of alternative domestic regulatory frameworks for abating emissions of greenhouse gases.

In Chapter 11, we return to a consideration of the “two-stage” approach and suggest one mechanism, based on a Presidential or Congressional commission, that might be adopted to learn from initial commercial-scale CCS projects before finalizing specific details of the regulatory approach. We then explain how we plan to use this interim report as a vehicle for soliciting advice and guidance from a wide range of experts and stakeholders. Based on this advice and our own further work, by late-2009 we plan to make recommendations for an institutional, legal and regulatory framework that can facilitate the rapid adoption of a U.S. regulatory environment for the capture, transport and deep geological sequestration of CO₂ that is safe, environmentally sound, affordable, compatible with evolving international carbon control regimes (including emissions trading) and socially equitable.

Contact information for us is provided on the inside cover of this report. It is our hope that readers will provide comments on the way in which we have framed the issues, help us to identify things we may have overlooked, and suggest arguments that should shape the final recommendations that we develop, including perhaps draft language for new enabling legislation.

Chapter 1: Why We Need Carbon Capture and Sequestration

Unless the world reduces its emissions of carbon dioxide (CO₂) by about 80% from current levels by the middle of this century, the future looks grim.¹ Our grandchildren may see the disappearance of summer sea ice in the Arctic, the end of polar bears in the wild, and the loss of sugar maples and most of the ski industry from New England.² Moreover, because sooner or later most CO₂ ends up in the ocean as carbonic acid, they may also see the end of coral reefs and the demise of many zooplankton at the bottom of food chains that feed salmon, whales, and other sea life.³ If the worst happens, their children may see all of southern Florida and the Gulf Coast disappear under rising sea levels.⁴

All that will be just the start. If the atmospheric concentration of CO₂ and other “greenhouse gases” continues to increase, climate change and its impacts will not only continue but accelerate.

We all want to leave a better world for our children and their children. So once we get past the short-term political posturing about whether climate change is real and whether we should lead the world in responding to this challenge, we will need to get serious about figuring out how to change the way that we produce and use energy—about how to reduce dramatically the emissions of that result from burning coal, oil, and natural gas.



Figure 1.1: Illustration of the impact on the southeastern U.S. coast of losing half the ice of Greenland, which would result in 3.5 meters of sea-level rise. Figure created by Jared T. Williams for Daniel Schrag of Harvard, who holds the copyright. Reproduced with permission.

¹ For a basic explanation of global warming, see http://www.ccsreg.org/climate_change.html. For a detailed review of the current state of scientific knowledge of climate change and its likely impact, see the IPCC Fourth Assessment reports, available at <http://www.ipcc.ch>.

² See, for example, <http://www.usgcrp.gov/usgcrp/nacc/> and <http://alaska.fws.gov/fisheries/mmm/polarbear/issues.htm>.

³ Orr, J. C.; Fabry, V. J.; Aumont, O., et al., Anthropogenic ocean acidification over the twenty-first century and its impact on calcifying organisms. *Nature* 2005, 437, (7059), 681-686.

⁴ See: <http://epa.gov/climatechange/effects/coastal/slrmaps.html>.



Figure 1.2: Illustration of the likely impact on coral reefs from the rise in atmospheric concentrations of CO₂ that can be expected by later this century. Photographs by O. Hoegh-Guldberg, reprinted from *Science* with permission.

1.1 Why the Continued Need for Fossil Fuel?

When the U.S. finally gets serious, and we set out to reduce our CO₂ emissions, won't we just convert to solar, wind, biomass, and nuclear, and switch to more energy efficient cars and appliances?

All these can help, but they also all have their limits. The sun doesn't shine at night or when there are clouds. Even in sunny Arizona, the output from solar arrays is only about 20% of what it would be under full sun all the time.⁵ Converting sunlight into electricity is still extremely expensive and appears likely to stay that way for decades to come.⁶ Similarly, the wind doesn't blow all the time. Until low-cost storage becomes available, gas turbines must be used to fill in the gaps. This results in continued dependency on imported fuel and can lead to air pollution.⁷ Strategies for storing electricity are still limited and expensive. Using biomass as an energy source requires lots of land and is already having dramatic impacts on world food prices.⁸ Nuclear power, which today is the source of about 20% of the electricity that we use in the U.S., is expensive and faces other problems that we all know about.⁹

On the other hand, there are big opportunities to save energy through improved efficiency, often at more modest cost and with fewer drawbacks. For example, 20% of all our electricity in the U.S. goes into lighting. Compact fluorescents are a good start, and within a few years, solid-state lighting could become even more efficient and cost effective.¹⁰ With better design, buildings can be made much more energy efficient. Regular hybrid and plug-in electric

⁵ Curtright, A. E.; Apt, J., The character of power output from utility-scale photovoltaic systems. *Progress in Photovoltaics* 2008, 16, (3), 241-247.

⁶ Curtright, A. E.; Morgan, M.G.; Keith, D.W., Expert assessments of future photovoltaic technologies. *Environmental Science and Technology*, in press.

⁷ Katzenstein, W.; Apt, J., Air emissions due to wind and solar power. *Environmental Science and Technology*, in press.

⁸ See, for example, the report of the International Risk Governance Council, *Risk Governance Guidelines for Bioenergy Policies*, available from http://www.irgc.org/IMG/pdf/IRGC_PB_Bioenergy_WEB-2.pdf.

⁹ *The Future of Nuclear Power*, report of an interdisciplinary MIT study. PDF available at <http://web.mit.edu/nuclearpower/>

¹⁰ Azevedo, I.L.; Morgan M.G.; Morgan F., The transition to solid state lighting. *Proceedings of the IEEE*, in press.

hybrid automobiles¹¹ also show promise to reduce both emissions and our dependency on imported oil.

Of course, the other thing that will complicate “decarbonizing” our energy system and improving the efficiency with which we use energy is the fact that we already have lots of expensive equipment and buildings in place. While we are a wealthy nation, we can’t afford to throw them all out and replace them with more efficient ones all at once.

In the U.S., we make roughly half of all our electricity from coal. Many other parts of the world make even larger fractions of their electric power from coal (Figure 1.3). Every analyst who has looked at the problem of how to decarbonize our energy system has reached the same conclusion: there is no single “silver bullet.” Reducing dramatically our CO₂ emissions in an affordable way is possible,¹² but it will take a portfolio of everything that we’ve got both on the supply side and in improved end-use efficiency.

“Reducing dramatically our CO₂ emissions in an affordable way is possible, but it will take a portfolio of everything that we’ve got...”

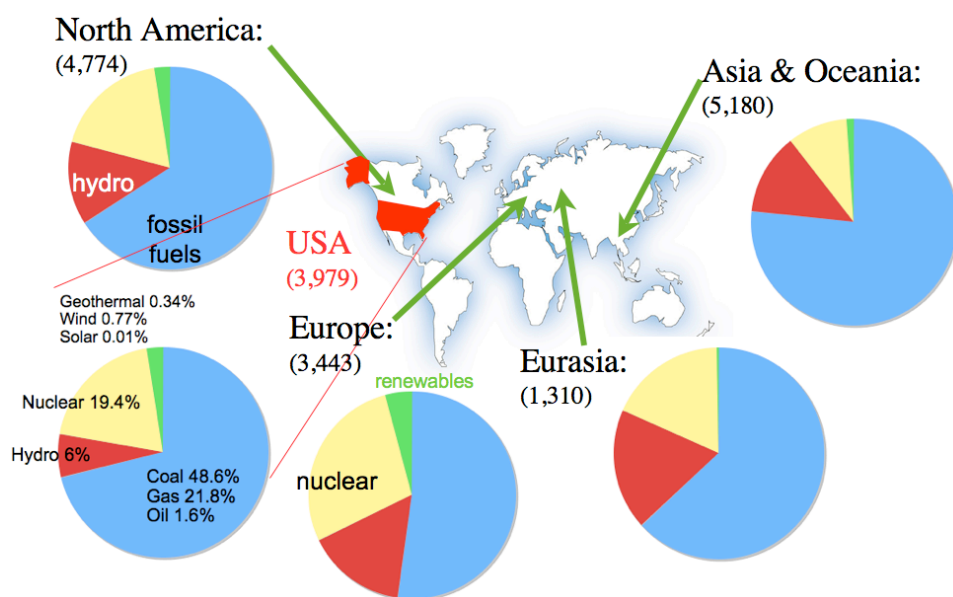


Figure 1.3: Sources of generated electric power in the U.S. and around the world in 2004. Numbers in parentheses are generation in billions of kilowatt hours. Note the high dependency on coal and other fossil fuels. Data in these pie charts are from the U.S. Energy Information Agency.

For at least the coming half century, there is simply no way to avoid using fossil fuel as a part of a portfolio of energy solutions. This means that we have to develop ways to use fossil fuels—especially coal for which we have ample domestic supplies for the coming century¹³ —without releasing CO₂ to the atmosphere.

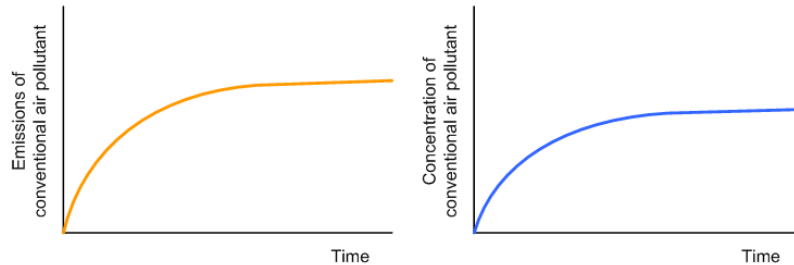
¹¹ Samaras, C.; Meisterling, K., Life cycle assessment of greenhouse gas emissions from plug-in hybrid vehicles: implications for policy. *Environmental Science and Technology* 2008, 42, (9), 3170-3176.

¹² A calculation done by Carnegie Mellon’s Jay Apt suggests that if the U.S. electricity system were to decarbonize in an orderly way over several decades, the cost would be comparable to what it cost the industry to meet the requirements of the Clean Air Act.

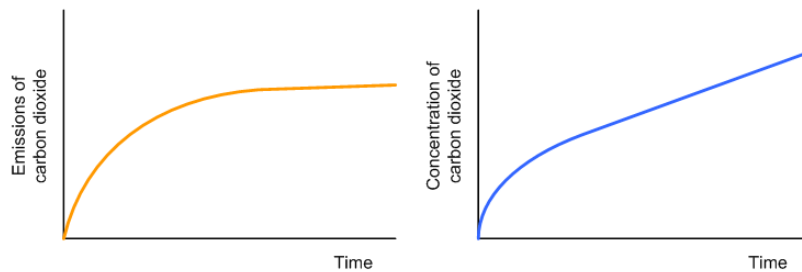
¹³ National Research Council, *Coal Research and Development to Support National Energy Policy*. National Academies Press: Washington, DC, 2007, p 184.

Box 1.1. Why do we say that the world must reduce its emissions of CO₂ by roughly 80% from current levels?

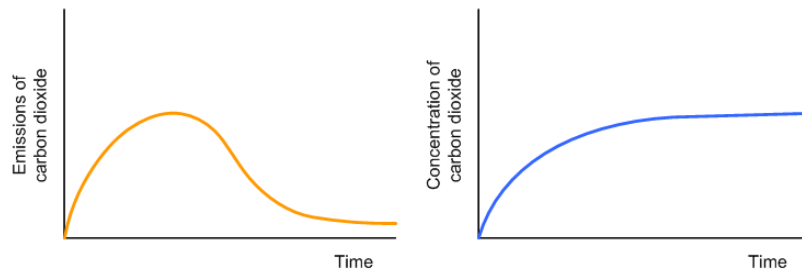
Carbon dioxide (CO₂) and the other greenhouse gases that produce global warming are not like regular air pollution such as sulfur dioxide (SO₂), oxides of nitrogen (NO_x), smog, and fine particles (PM). These conventional air pollutants remain in the atmosphere only for a few hours or days. If the emissions that produce these conventional air pollutants are stabilized, their concentration in the atmosphere is also quickly stabilized.



That is not true of CO₂ and most other greenhouse gases produced by human activities. Much of the CO₂ that enters the atmosphere stays there for 100 years or more. If we only stabilized emissions, the atmospheric concentrations that cause warming would continue to rise.



If we want to reduce atmospheric concentrations, we must reduce emissions by something like 80%:



A useful analogy is a bathtub (the atmosphere) with a very large faucet (human emissions) and a much smaller drain (natural processes that remove CO₂ and other greenhouse gases from the atmosphere). Unless the faucet is turned way down, the bathtub continues to fill up.

China's CO₂ emissions recently passed those of the U.S. Emissions from India and others are also growing. However, it will be decades before these additions to the "global bathtub" of atmospheric CO₂ climb to the quantities that the U.S., Europe, Japan, and other developed countries have already poured in.

Sometimes experts argue about exactly how much reduction is needed. The amount of reduction depends on what people think a "safe level" of CO₂ in the atmosphere is. The exact amount is far less important than the basic insight that we need to achieve a very deep reduction.

1.2 Carbon Capture with Deep Geological Sequestration

Fortunately, there are a handful of technologies that can capture CO₂ either before or after fossil fuel is burned and keep it from entering the atmosphere. While most of these technologies exist today at commercial scale in other applications, they are only just now being applied to the problem of capturing CO₂ emissions from the energy system.

To get some idea of how much CO₂ our energy system now produces, consider just the one big power plant shown in Figure 1.4. Coal for this plant arrives in barges on the Ohio River, but it is perhaps easier to visualize the amount of coal in terms of standard 100-ton railroad hopper cars. A plant this size burns about 200 100-ton railcars of coal every day. Of course, some of what is in coal isn't carbon. If we consider just the carbon content of the coal, that would come to about 150 similarly-size railcars of carbon every day. Hence, every day such a plant converts that much carbon into invisible CO₂ gas and releases it to the atmosphere. There are hundreds of plants like this all across the U.S.



Figure 1.4: The 2,460 megawatt Bruce Mansfield power plant located just west of Pittsburgh, PA.

Of course, the coal came out of the ground. The idea of CCS¹⁴ is to capture and compress the CO₂ into a dense liquid (technically a supercritical fluid) and put it back into appropriate geological formations deep underground where it can be safely and permanently deposited, or “sequestered.”

The key words here are “safely” and “permanently.” If large quantities of CO₂ are going to be sequestered underground in the U.S. over the coming decades, clearly there need to be regulations that assure that this will happen safely and effectively. The objective of the CCSReg project is to develop proposals for a regulatory framework for the capture, transport, and deep geological sequestration of CO₂ that is safe, environmentally sound, affordable, compatible with evolving international carbon control regimes (including emissions trading), and socially equitable.

1.3 The Boundaries and Life Cycle of a CCS Project

Carbon capture and storage directly involves three steps: CO₂ capture, transport to the injection site, and injection deep underground to achieve “sequestration.” These three steps are illustrated in Figure 1.5. In the first step, CO₂ is captured from large point sources using any of a number of different processes (described in Chapter 2). It is then dried, compressed, and cooled, converting gaseous CO₂ to a supercritical fluid. Supercritical CO₂ is moved from the site of capture to the site of injection, typically by pipeline (described in Chapter 3), although oceangoing tankers (similar to LNG tankers) could also be used where appropriate.¹⁵ Once at the site of injection, CO₂ is injected into a geologic formation deep enough below the surface that the CO₂ remains as a supercritical fluid. The minimum depth that meets this criterion is typically 800 m or 2,600 ft, although the precise depth varies from one location to another.¹⁶ Issues related to the selection of, access to, and use of injection sites are discussed in Chapter 5, and issues that arise during the operational phase of a project are discussed in Chapter 6.

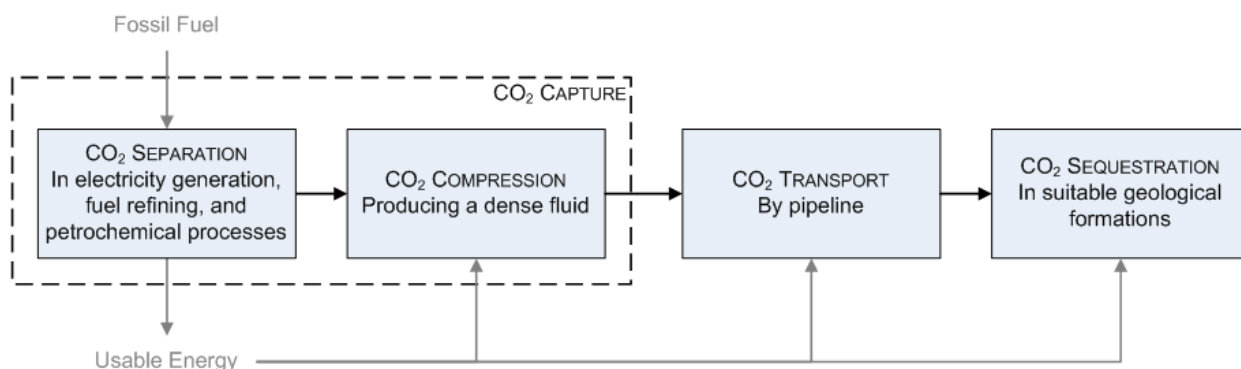


Figure 1.5: The steps in the capture and deep geological sequestration of CO₂.

¹⁴ The initials CCS are used interchangeably to refer to “carbon capture and sequestration” or “carbon capture and storage” as the same thing is often called, especially in Europe. The word storage is defined as “the act of storing” and the verb to store is defined as “v.t. to supply or stock with something, as for future use ... to accumulate or put away for future use ...”. There is no way that more than a minuscule amount of the CO₂ injected deep underground in CCS will ever be removed for use in the future. Hence, in the interests of accuracy, we use the word sequester, which is defined as “to remove or withdraw into solitude ...”. (Definitions from the Random House Unabridged Dictionary).

¹⁵ Svensson, R.; Odenberger, M.; Johnsson, F., et al., Transportation systems for CO₂-application to carbon capture and storage. *Energy Conversion and Management* 2004, 45, 2343-2353.

¹⁶ Bachu, S., Screening and ranking of sedimentary basins for sequestration of CO₂ in geological media in response to climate change. *Environmental Geology* 2003, 44, 277-289.

The infrastructure involved in doing CCS is expensive and has a long life. Power plants that might install CO₂-capture systems typically have a life of at least thirty years, although in the U.S. today many coal-fired power plants are much older (Figure 1.6). The CO₂ captured from these plants will be sent to one or more storage sites having an operational life of a similar span.

Both a power plant and the associated storage site (or sites) will require several years of lead time before full scale operation could commence. However, in contrast to a power plant, a storage site will require a long-term commitment after the site ceases injection, during which the site will need to be monitored to ensure that the injected CO₂ is behaving as expected. Issues of site closure are discussed in the final section of Chapter 6 and issues related to the long-term stewardship of a closed site are discussed in Chapter 7.

1.4 Purpose and Layout of this Interim Report

All of the phases of a CCS project outlined in Figure 1.5 will require regulatory oversight of some type. The U.S. EPA recently released draft regulations that cover portions of the operational and post-injection phase of an injection project. However, because they have developed those draft regulations under the authorization provided to them under the Safe Drinking Water Act (42 U.S.C. 300h et seq.) the scope of issues they have been able to cover is much narrower than the scope of regulatory issues that will have to be addressed in order to make future CCS projects safe, environmentally sound, affordable, compatible with evolving international carbon control regimes (including emissions trading), and socially equitable.

The objective of the CCSReg project is to help develop this needed broader regulatory framework. While it is our plan to develop definitive recommendations for how best to address regulatory needs across the full range of issues identified in Figure 1.5, this “Interim Report” has the more modest objective of structuring the questions about regulatory design that we believe must be addressed across each phase of CCS development, operation and long-term stewardship.

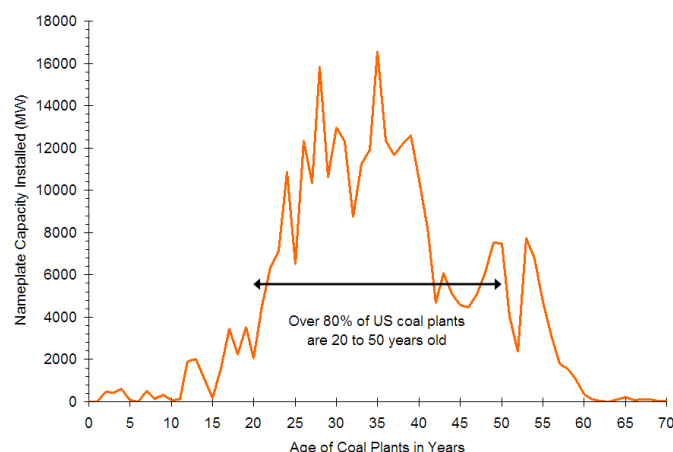


Figure 1.6: Age distribution of coal-fired power plants in the U.S.

There are a few places we take firm positions. For example, we argue that it would be premature to put a definitive regulatory framework in place to govern CCS until after the world has gained several years of experience with a number of large projects—perhaps 10 or so, storing more than a million tonnes per year.¹⁷ We also argue that, because it will never be possible to fully know the structure and performance of a geological reservoir

¹⁷ Friedmann, S. J., The scientific case for large CO₂ storage projects worldwide: Where they should go, what they should look like, and how much they should cost. In *8th International Conference on Greenhouse Gas Control Technologies*, Elsevier Science: Trondheim, Norway, 2006.

before large-scale injection begins, any regulatory approach will need to be able to respond adaptively as more is learned during the course of the operation of a large-scale injection site.

While we are a diverse interdisciplinary team (see the list of team members inside the front cover of this report), assisted by an even more diverse advisory committee (Table 1.1), there is no way we will be able to fully understand the regulatory issues that must be addressed for the governance of CCS without the help and advice of many others. The objective of this interim report is to lay out our initial thinking and seek such input from as wide a set of individual and organizations as possible.

We hope that after reading this report you will send us your critical comments and advice. Details on how to contact us are provided on the inside front cover of this report.

Table 1.1: Members of the Advisory Board for the CCSReg project. Note that, while acting as individuals, these folks have kindly agreed to provide us with advice and guidance, neither they nor their organizations bear any responsibility for the contents of this report or the other products of the CCSReg project.

Name	Title	Organization
Carl O. Bauer	Director, National Energy Technology Laboratory	U.S. Department of Energy
Armond Cohen	Executive Director	Clean Air Task Force
Brad Crabtree	Program Director	Great Plains Institute
David Fleischaker	Secretary of Energy	State of Oklahoma
Ottmar Edenhofer	Co-Director, Sustainable Solutions Research Track	Potsdam Institute for Climate Impact Research
Jeanne M. Fox	President	New Jersey Board of Public Utilities
Kathleen A. McGinty	Former Secretary of Environmental Protection, Commonwealth of Pennsylvania	
Susan D. Hovorka	Principal Investigator, Gulf Coast Carbon Center, Bureau of Economic Geology	University of Texas at Austin
Ernest J. Moniz	Director, Laboratory for Energy and Environment and Director, MIT Energy Initiative	MIT
Paul O'Neill	Former Secretary of the Treasury, CEO of Alcoa	
Michael Oppenheimer	Director, Program in Science, Technology and Environmental Policy, Woodrow Wilson School	Princeton University
Jonathan C. Pershing	Director, Climate, Energy and Pollution Program	World Resources Institute
Philip R. Sharp	President	Resources for the Future
Brian Hannegan	Vice President, Environment and Generation	Electric Power Research Institute
Henry A. Courtright	Senior Vice President, Member Services	Electric Power Research Institute
Jeffrey E. Sterba	Chairman, President and CEO	PNM Resources
Susan E. Wefald	President	North Dakota Public Service Commission

Chapter 2: Carbon Dioxide Capture

Carbon dioxide (CO₂) can be captured from a large number of industrial processes, including power generation. Systems are also being developed to capture CO₂ directly from the air. Regardless of the process, the economics of CO₂ capture and transport exhibit returns to scale—the unit cost of capturing CO₂ decreases with increasing capture rate—thus, it is large point sources of CO₂ that are typically considered for CO₂ capture. Typical features of various large point sources of CO₂ are shown in Table 2.1.

Table 2.1: Typical direct emissions rates from large point sources of CO₂. Actual emissions rates will vary from these numbers depending on the specific feedstocks and processes employed and do not include life cycle emissions. Estimates for electric power generation come from the Integrated Environmental Control Model (IECM), for coal-to-liquids (CTL) synthetic fuels from Mantripragada and Rubin, and those for chemical, petrochemical, and other industrial processes from the International Energy Agency.^{1,2,3}

Process	CO ₂ Source	Size	CO ₂ Emissions (Mt/y)
Electric Power Generation*			
NGCC	Combustion—natural gas	500 MW _e	1.2
SCPC	Combustion—coal	500 MW _e	2.7
IGCC	Gasification—coal	500 MW _e	2.7
Chemical & Petrochemical			
CTL-Synthetic Fuels	Gasification & Fischer-Tropch synthesis	50,000 bbl/day	10
Ethylene Production	Thermal cracking of light hydrocarbons	700,000 tonnes/y	1.7
Ammonia Production	Haber-Bosch process	500,000 tonnes/y	0.6
Hydrogen Production	Steam-methane reforming	70,000 tonnes/y	0.3
Other Industrial			
Integrated Steel Production	Blast furnace emission	3,000,000 tonnes/y	3.8
Cement Production	Clinker production	700,000 tonnes/y	0.6

* A plant capacity factor of 75% is used for each of the power plants; NGCC, SCPC, and IGCC refer to Natural Gas Combined Cycle, Supercritical Pulverized Coal, and Integrated Gasification Combined Cycle plants, respectively.

This chapter presents a brief overview of capture technologies and points out several issues that should be considered in the context of developing a regulatory framework for CO₂ capture and deep geological sequestration.

¹ Rubin, E. S.; Berkenpas, M. B.; Zaremsky, C. J. *User Manual: Integrated Environmental Control Model with Carbon Capture and Storage*; Carnegie Mellon University: Pittsburgh, PA, May, 2007; <http://www.iecm-online.com/PDF%20files/2007/2007ra%20Rubin%20et%20al.%20IECM%20User.pdf>.

² Mantripragada, H., The CO₂ Reduction Potential of Coal-to-Liquids Plants. In *Seventh Annual Conference on Carbon Capture and Sequestration*, Exchange Monitor Publications: Pittsburgh, PA, 2008.

³ Hendriks, C.; van der Waart, A. S.; Byers, C., et al. *Building the Cost Curves for CO₂ Storage, Part 1: Sources of CO₂*; IEA Greenhouse Gas R&D Programme: Stoke Orchard, UK, 2002.

“Capture of CO₂ from electric power generation can be accomplished via three general routes: pre-combustion CO₂ capture,... post-combustion CO₂ capture,... and oxyfuel combustion ...”

“There are a number of IGCC power plants operating, located in the U.S., Europe, and Japan...”

2.1 Capture of CO₂ from Electric Power Generation

Capture of CO₂ from electric power generation can be accomplished via three general routes: pre-combustion CO₂ capture, where carbon is removed from the fuel prior to oxidation; post-combustion CO₂ capture, where fuel is combusted normally in a boiler or turbine, and CO₂ is then removed from the exiting flue gas stream; and oxyfuel combustion, where the fuel is combusted with nearly stoichiometric amounts of oxygen in an atmosphere of CO₂. Figure 2.1 summarizes the major flows and processes in the three categories of capture processes. Pre- and post-combustion capture processes are currently commercially available, while oxyfuel is still under development.

Pre-Combustion Capture: Pre-combustion CO₂ capture is characterized by decarbonization of the fuel prior to combustion in a gas turbine. If the starting fuel is a solid, such as coal, petroleum coke,⁴ or biomass (e.g., wood chips, switchgrass, etc.), the fuel is converted to a gas through partial oxidation of carbon in the fuel in the presence of oxygen. The resulting gas, referred to as “syngas,” consists primarily of hydrogen (H₂), carbon monoxide (CO), and light hydrocarbons—typically methane (CH₄), depending on the gasifier design. At this point, the gas can be treated to remove hydrogen sulfide (H₂S) and fine particulates, and then burnt in a combined cycle gas turbine to generate electricity.⁵ This is referred to as an Integrated Gasification Combined Cycle (IGCC) plant. There are a number of IGCC power plants operating, located in the U.S., Europe, and Japan (see Box 2.1). In addition, there are hundreds of coal gasifiers operating around the world providing feed-stock to chemical plants.

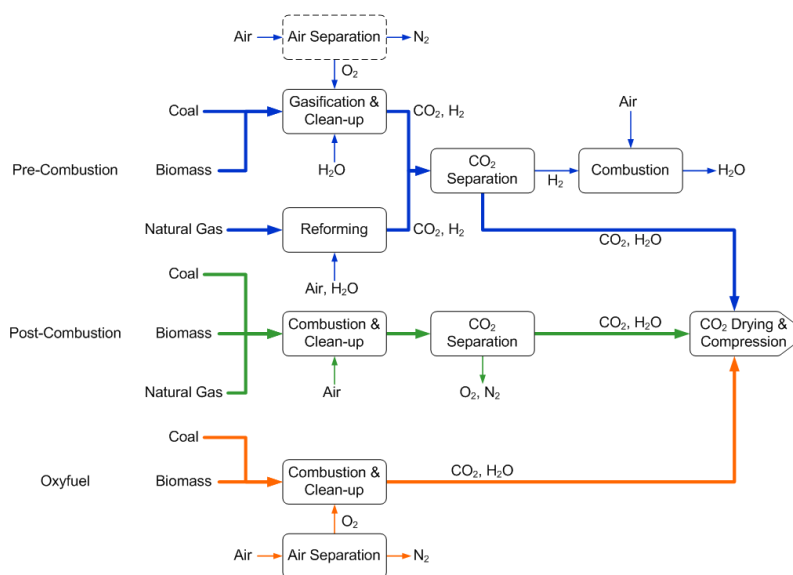


Figure 2.1: CO₂ capture processes in electric power generation summarized by major process steps, where the thick lines show the path of carbon through the processes, adapted from the IPCC Special Report on CCS.⁶

⁴ Petroleum coke (petcoke) is a carbon rich residue that remains after upgrading of heavy oil.

⁵ A combined cycle gas turbine operates with both a topping cycle and a bottoming cycle. The topping cycle converts the potential energy in the hot combustion products into electricity via a generator. The bottoming cycle extracts thermal energy from the hot gas turbine exhaust by generating steam and converting the steam into electricity via steam turbine and generator.

⁶ Thambimuthu, K.; Soltanich, M.; Abanades, J. C., et al., Capture of CO₂. In *IPCC Special Report on Carbon Dioxide Capture and Storage*, Metz, B.; Davidson, O.; de Coninck, H.; Loos, M.; Meyer, L., Eds. Cambridge University Press: Cambridge, U.K., 2005.

Box 2.1: Operating IGCC and CO₂ capture pilot plants

In the United States, there are three operating IGCC facilities. While none of these capture CO₂, they demonstrate the viability of gasification for power generation. Development of two of these facilities were both supported by the U.S. Department of Energy, and are located in Polk County, FL (250 MW) and Terre Haute, IN (260 MW). The third is a co-generation facility located in Delaware City, DE (160 MW). There are plans to build several other IGCC facilities in the United States, although none of these facilities would capture CO₂ for sequestration at scale. There are a further nine large (i.e., 100 MW or greater) IGCC plants operating today elsewhere in the world, such as in Buggenum, Netherlands (250 MW); Nakoso, Japan (230 MW); and Puertollano, Spain (300 MW).⁷ Most of these facilities generate electricity from byproducts of refining processes such as petroleum coke, residual oil, and asphalt and are not operated by electric utilities.



Image source: U.S. DOE

There is also another notable capture pilot plant operating in Germany. This is the Vattenfall Schwarze Pumpe oxyfuel demonstration plant, which generates approximately 10 MW electric. The captured CO₂ is transported by truck to a storage site where it will be used for enhanced gas recovery (EGR).



Image source: Vattenfall AB

⁷ The number of plants, location, and output is based on the Gasification Technologies Council Online Gasification Database (<http://www.gasification.org/database1/search.aspx>) as of November 24, 2008.

In an IGCC plant with CO₂ capture, shown more clearly below in Figure 2.2, the hydrogen content of the synthesis gas is increased by reacting CO in the synthesis gas with water in the water gas shift reaction. Through this reaction, CO is converted to CO₂, which is then removed from the fuel using a separation process. Prior to CO₂ separation, H₂S produced during gasification would also be removed and converted to elemental sulfur, or if regulations were to allow, it could be co-captured and sequestered with CO₂.

Processes to separate CO₂ from the gas stream include:

- physical absorption of the CO₂ into a solvent which is then regenerated through pressure and temperature changes;
- adsorption of the CO₂ onto a solid that is periodically regenerated, releasing the CO₂ (pressure and temperature swing adsorption); and,
- transfer of the CO₂ across a thin membrane, permeable to only CO₂.

For IGCC systems, the preferred separation method is physical absorption using a solvent as this technology is commercially available and can be scaled to handle large volumes of CO₂ most easily. For production of pure H₂, solid sorbents are preferred, as they yield a higher purity product. Membrane systems are largely under development.

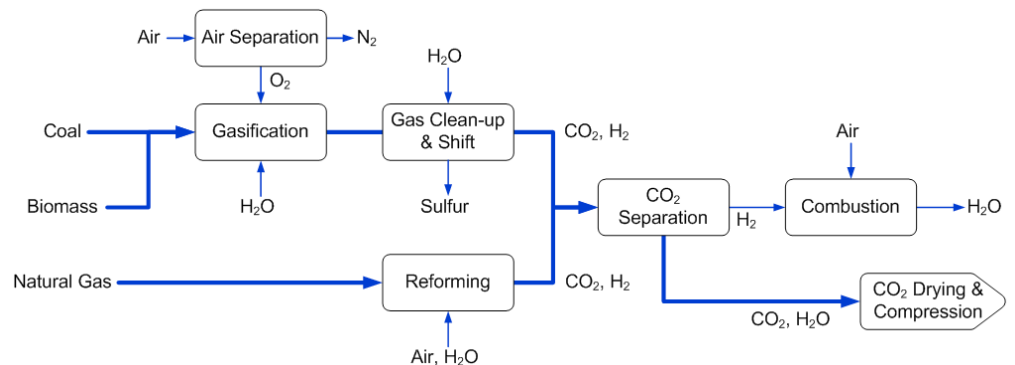


Figure 2.2: An expanded view of the post-combustion CO₂ capture processes for electricity generation where the thick lines show the flow of carbon through the process.

If natural gas is used as the fuel for a pre-combustion capture process, the gas (which is primarily CH₄) is converted to H₂ and CO₂ through steam-methane reforming.⁸ In this process, CH₄ and steam are converted to H₂ and CO that is shifted (via the water-gas shift reaction) to H₂ and CO₂. The subsequent CO₂ separation and combustion processes are the same as in the IGCC case, save for H₂S removal, since the sulfur content of sweetened natural gas is typically very low.

⁸ Other conversion processes, such as partial oxidation and autothermal reforming, are possible.

Post-Combustion Capture: CO₂ capture using these methods involves combustion of fossil fuels in the traditional manner—either in a boiler or a combined cycle gas turbine—and subsequent separation of CO₂ from the flue gas. While a variety of processes are capable of separating CO₂ from other flue gas constituents, the current preferred option is absorption using a chemical sorbent such as amines or ammonia. However, where solid fuels, such as coal or biomass, are used, concentrations of acid gases like SO_x or NO_x in the flue gas must be substantially reduced to prevent degradation of the solvent.⁹

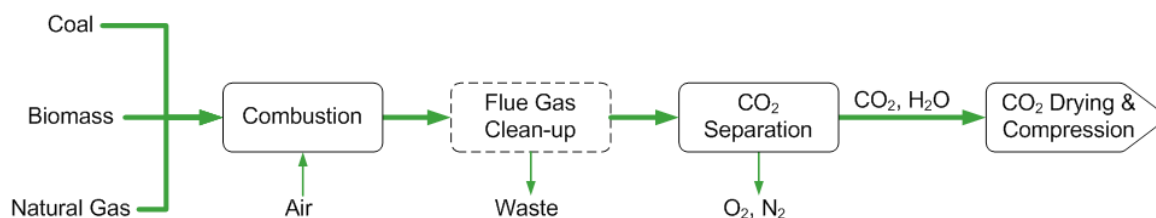


Figure 2.3: A flow diagram showing the flow of carbon in post-combustion CO₂ capture. Flue gas clean-up is only required for solid fuels, as natural gas contains low concentrations of sulfur and combustion can be controlled to minimize the concentration of NO_x.

Oxyfuel Capture: The third option for CO₂ capture is the combustion of biomass or coal in an atmosphere of oxygen and CO₂, rather than in air.¹⁰ In this case, the only products of combustion are water and CO₂ so that no CO₂ separation is required.¹¹ However, an air separation unit is needed to produce oxygen.

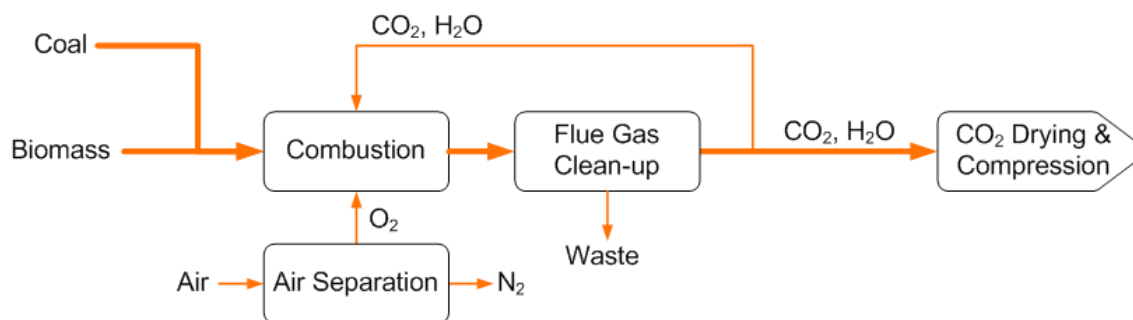


Figure 2.4: A flow diagram showing the flow of carbon in oxyfuel combustion.

To control the temperature of combustion in the boiler, CO₂-rich flue gas produced from combustion is recycled back into the boiler. Prior to recycling part of the flue gas stream, conventional pollutants, such as fly ash and SO_x, are typically removed to make handling the flue gas easier and control the concentration of these pollutants in the CO₂ that is compressed for sequestration.

⁹ Thambimuthu, K.; Soltanich, M.; Abanades, J. C., et al., Capture of CO₂ In *IPCC Special Report on Carbon Dioxide Capture and Storage*, Metz, B.; Davidson, O.; de Coninck, H.; Loos, M.; Meyer, L., Eds. Cambridge University Press: Cambridge, U.K., 2005.

¹⁰ Air is approximately 78% nitrogen, 21% oxygen, and the remainder is primarily argon and CO₂.

¹¹ Depending on the content of materials in the fuel there will be small amounts of conventional pollutants, such as SO_x. Since combustion is not taking place in air, which is rich in nitrogen, NO_x that is formed will come primarily from nitrogen in the fuel.

Compression and liquefaction of the captured CO₂ is the final step in all of the capture processes. During this step, the concentration of water in the CO₂ must be reduced to meet requirements for subsequent transport to prevent formation of CO₂ hydrates and to avoid corrosion problems. In addition, the concentration of gaseous components such as N₂, O₂ and Ar may have to be reduced, particularly if the CO₂ is used for EOR applications.¹²

Energy Penalty Impacts: All of these types of capture systems currently require large amounts of energy for their operation, resulting in decreased plant efficiencies and reduced net power outputs when compared to the same plants without capture systems. Because of the energy consumption for CO₂ separation and compression, the emissions of CO₂ avoided by capturing CO₂ are always less than the amount of CO₂ captured. This notion is illustrated in Figure 2.5.

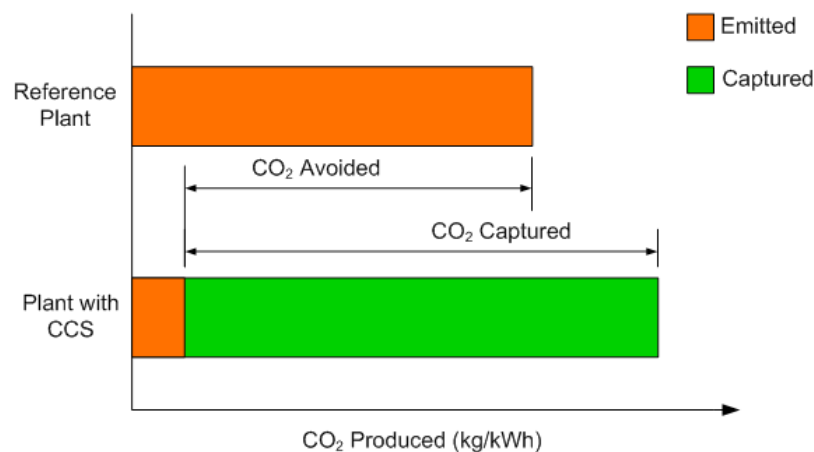


Figure 2.5: Illustration showing the relative difference between CO₂ captured and emissions avoided.¹³

In addition, reduced efficiency of electric power generation means that power plants with capture systems will consume more fuel and water while producing more waste products (e.g., ash, slag, and sulfur) per unit of electricity generated than a plant without capture.¹⁴ This increase in resource consumption can be quantified by the energy penalty, which is the increase in plant energy input per unit of product or output.¹⁵ Table 2.2 shows that the energy penalty ranges from 16% to 31% depending on the plant type. The results reported in this table agree broadly with those from other recent studies.¹⁶

¹² Aspelund, A.; Jordal, K., Gas conditioning--The interface between CO₂ capture and transport. *International Journal of Greenhouse Gas Control* 2007, 1, (3), 343-354.

¹³ Adopted from Metz, B.; Davidson, O.; de Coninck, H., et al., *IPCC Special Report on Carbon Dioxide Capture and Storage*. Cambridge University Press: Cambridge, U.K., 2005; p 442.

¹⁴ Rubin, E. S.; Chen, C.; Rao, A. B., Cost and performance of fossil fuel power plants with CO₂ capture and storage. *Energy Policy* 2007, 35, (9), 4444-4454.

¹⁵ Formally, this is defined as $\eta_{ref}/\eta_{ccs} - 1$

¹⁶ Recent studies are summarized in MIT *The Future of Coal*; Massachusetts Institute of Technology: Boston, MA, 2007, and Metz, B.; Davidson, O.; de Coninck, H., et al., *IPCC Special Report on Carbon Dioxide Capture and Storage*. Cambridge University Press: Cambridge, U.K., 2005; p 442.

Table 2.2: Key assumptions and baseline results from Rubin et al.¹⁷ Note that levelized costs were estimated using a fixed charge factor of 14.8%, a capacity factor of 75%, and compression of captured CO₂ to 2000 psig (13.7 MPa).

Parameter	PC ^a		IGCC ^b		NGCC ^c	
	Reference	Capture	Reference	Capture	Reference	Capture
Gross plant size (MW)	575	710	615	596	517	517
Net plant size (MW)	528	493	538	493	507	432
Efficiency, HHV (%)	39.3	29.9	37.2	32.2	50.2	42.8
CO ₂ Capture system		Amine		Shift + Selexol		Amine
CO ₂ Capture efficiency (%)		90		90		90
CO ₂ Emission Rate (kg/MWh)	811	107	822	97	367	43
CCS Plant Derate (% output loss)		23.9		13.4		14.7
CCS Energy Penalty (% fuel input/kWh)		31.4		15.5		17.3
TCR (\$/kW)	1442	2345	1567	2076	671	1091
LCOE (\$/MWh)	53.0	88.0	55.5	71.9	60.3	80.6
Cost of CO ₂ avoided (\$/tonne CO ₂) ^d		49.7		22.6		62.6
Cost of CO ₂ Captured (\$/tonne CO ₂)		36.5		19.3		52.5

All costs in constant 2005 U.S. \$ and do not include transport and storage.

^aSupercritical boiler unit; environmental controls include SCR, ESP and FGD systems, followed by MEA system for CO₂ capture; SO₂ removal efficiency is 98% for reference plant and 99% for capture plant.

^bBased on GE quench gasifier (2 + 1 spare), 2 GE 7FA gas turbine, 3-pressure reheat HRSG with steam parameters 1400 psig/1000 F/1000 F. Sulfur removal efficiency is 98% via hydrolyzer and Selexol system; Sulfur recovery via Claus plant and Beavon-Stretford tailgas unit.

^cNGCC plant used to GE 7FA gas turbines and 3-pressure reheat HRSG.

^dAll avoided cost values are relative to the reference plant for the same system.

It is critical to note that the amount of CO₂ avoided based on the results in Table 2.2 only accounts for the avoided direct emissions from power generation. If the boundary of the capture system is increased to include second order emissions from the coal supply chain, sorbent production chain, and the production chain of reagents for other environmental control systems, the emissions reduction is smaller than the emissions avoided by capture. For example, Koorneef et al. have estimated that, including second order emissions, the emissions reduction for a pulverized coal-fired power plant with post-combustion capture, such as shown in Figure 1.3, will be 71%, as opposed to the 87% for just the plant itself.¹⁸

The decrease in energy output coupled with the increased operating cost and increased capital cost (resulting from the capture system) results in a higher levelized cost of electricity (LCOE) for capture plants than those that have

¹⁷ Rubin, E. S.; Chen, C.; Rao, A. B., Cost and performance of fossil fuel power plants with CO₂ capture and storage. *Energy Policy* 2007, 35, (9), 4444-4454.

¹⁸ Koorneef, J.; van Keulen, T.; Faaij, A., et al., Life cycle assessment of a pulverized coal power plant with post-combustion capture, transport and storage of CO₂. *International Journal of Greenhouse Gas Control In Press, Corrected Proof*.

no capture. Table 2.2 shows that, with current designs, the cost of electricity from a power plant capturing CO₂ can be expected to increase between 30% and 70% relative to the reference plant, but as noted below, this can be expected to decline as experience is gained with more plants.

The technological maturity of CO₂ capture systems varies from technology to technology. The recent IPCC report concludes that the components of many capture systems are well understood from a technological standpoint, but there is a lack of experience in building and operating capture systems at scale in the electric utility industry.¹⁹ More recent work on learning curves associated with CCS, by Rubin and his coworkers, suggests that costs may increase for the first several plants as design and operating strategies are refined. However, once this period is past the cost of energy from power plants with CO₂ capture can be expected to decrease by between 3% and 5% for each doubling of worldwide installed capacity.²⁰ Worldwide capacity is used as the metric for learning, implying that the barriers for technology and knowledge transfer are relatively low. However, if a nation such as China were to develop CCS technology domestically, Chinese contractors could gain a considerable competitive advantage in being able to build and operate these plants. While there has been talk in the U.S. about transferring CCS technology to countries such as China, at the moment, given slow progress in the U.S. and CCS developments in China, the direction of technology transfer may be in doubt.

2.2 Capturing CO₂ from Industrial Processes

The ease with which CO₂ can be captured from industrial processes is highly dependent on the nature of the process. Capture from some processes, such as gas cracking to produce ethylene, gas processing, and coal-to-liquids (CTL) is relatively simple and low cost because CO₂ separation is already a necessary part of the process. For others, such as cement production, capture will be more complex and costly.

Processes can be grouped into those that currently produce a relatively high purity stream of CO₂ and vent it to the atmosphere, and those that do not or produce CO₂ both from combustion and chemical reaction. Table 2.3 describes the CO₂ source and capture processes for these industrial processes.

It is important to note that of the four integrated commercial-scale CCS projects operating today (see Box 2.2), three capture CO₂ from natural gas processing and one from synthetic natural gas production. There are also a number of facilities in the U.S., primarily ammonia production and gas processing, that capture CO₂ for use in enhanced oil recovery.

¹⁹ Thambimuthu, K.; Soltanieh, M.; Abanades, J. C., et al., Capture of CO₂. In *IPCC Special Report on Carbon Dioxide Capture and Storage*, Metz, B.; Davidson, O.; de Coninck, H.; Loos, M.; Meyer, L., Eds. Cambridge University Press: Cambridge, U.K., 2005.

²⁰ Rubin, E. S.; Yeh, S.; Antes, M., et al., Use of experience curves to estimate the future cost of power plants with CO₂ capture. *International Journal of Greenhouse Gas Control* 2007, 1, (2), 188-197.

Table 2.3: Summary of CO₂ capture options from industrial processes.

Process	CO ₂ Source	Technology	Relative Capture Cost ^a
Inherent CO ₂ separation			
Gas Processing ²	Natural gas commonly contains CO ₂ and other components that are removed so that the gas meets pipeline specifications (i.e., approximately 2% CO ₂).	- Physical and chemical solvents (e.g., Selexol, MDEA) - Membranes - Phase change (e.g., ExxonMobil CFZ)	Low—Clean-up and compression only.
CTL-Synthetic Fuels ³	Syngas, produced from gasification, is used to produce liquid fuels. CO ₂ is separated from the syngas both prior and after conversion to liquid fuels.	- Physical and chemical solvents (e.g., Selexol, MDEA) - Membranes	Low—Clean-up and compression only.
Ammonia Production ⁴	In the U.S., ammonia is typically produced from steam reforming of natural gas with a subsequent shift to produce H ₂ and CO ₂ . The CO ₂ is normally separated from the hydrogen, which is then combined with N ₂ to produce ammonia. CO ₂ from ammonia synthesis is sold for Enhanced Oil Recovery in some cases.	- Physical and chemical solvents (e.g., Selexol, MDEA) - Membranes	Low—Clean-up and compression only.
CO ₂ from multiple sources			
Hydrogen Production ⁵	Natural gas can be converted to hydrogen through steam-methane reforming (SMR), partial oxidation (POX), and autothermal reforming (ATR). In all of these processes, CO ₂ is separated from H ₂ in normal operation; however, for SMR and POX current processes will require additional separation.	- Physical solvents (e.g., Selexol, MDEA) - Membranes - Pressure-swing adsorption	Comparable—May require addition of flue-gas separation.
Ethylene Production	Ethylene is typically produced from the thermal cracking and reforming of some combination of ethane, propane, butane, and naphtha. CO ₂ is separated from the produced stream of ethylene to meet quality requirements; however, CO ₂ is not normally captured from fired heaters.	- Physical and chemical solvents (e.g., Selexol, MDEA) - Membranes	Comparable—May require addition of flue-gas separation.
Cement Production ⁶	CO ₂ is generated directly through calcination as well as from combustion of fossil fuels to produce heat for the calcining reaction.	- Physical and chemical solvents (e.g., Selexol, MDEA) - Oxyfuel combustion	High—Similar processes are not in use at cement plants today.
Integrated Iron and Steel ⁷	In traditional processes, CO ₂ is released from coke production, and combustion in a blast furnace. Some more recent processes forgo the use of coke and use coal directly and are more amenable to CO ₂ capture.	- Oxyfuel combustion for blast furnaces - Direct reduction of iron ore by hydrogen derived from gasification.	Unknown—Would require significant addition of equipment and changes in operation.

^a Relative to the cost of CO₂ capture of \$39.5/tonne for the PC plant with capture described in Section 2.1 not including transport and storage.

21 Thambimuthu, K.; Soltanich, M.; Abanades, J. C., et al., Capture of CO₂. In *IPCC Special Report on Carbon Dioxide Capture and Storage*, Metz, B.; Davidson, O.; de Coninck, H.; Loos, M. Meyer, L., Eds. Cambridge University Press: Cambridge, U.K., 2005.

22 Ibid.In.

23 Ibid.In.

24 Ibid.In.

25 Hassan, S. M. N.; Douglas, P. L.; Croiset, E., Techno-Economic Study of CO₂ Capture from an Existing Cement Plant Using MEA Scrubbing. *International Journal of Green Energy* 2007, 4, (2), 197 - 220.

26 Gielen, D., CO₂ removal in the iron and steel industry. *Energy Conversion and Management* 2003, 44, (7), 1027-1037.

Box 2.2: Integrated CCS projects operating today

There are four operating CCS projects today that involve capture, transport and injection of CO₂ for the purpose of sequestration. These projects are listed in the table below.

Project	Location	Operator	Storage Type	Injection Start Date	Annual Injection Rate	Total Planned Storage
Sleipner	North Sea	StatoilHydro	Aquifer	1996	1 Mt/y	20 MT
Weyburn	Saskatchewan, Canada	EnCana	EOR	2000	1.2 Mt/y	19 Mt
In Salah	Sahara, Algeria	Sonatrach, BP, StatoilHydro	Depleted Gas Reservoir	2004	1.2 Mt/y	17 Mt
Shohvit	Melkøya, Norway	StatoilHydro	Aquifer	2007	0.7 Mt/y	

2.3 Capturing CO₂ Directly from the Air

There is interest in direct capture of CO₂ from the air because the cost of this technology presents an upper bound (or “backstop”) on the cost of removing carbon from all sectors of the economy.^{27, 28} Air capture could potentially remove more CO₂ from the atmosphere than is emitted from human activities. As a result, air capture may afford society the option of directly reducing atmospheric concentrations of CO₂.²⁹ Viable air capture technology could be particularly attractive as a strategy for dealing with emissions from small and mobile sources such as automobiles and aircraft.³⁰

Direct air capture can be performed using a number of different technologies and configurations.^{31, 32, 33, 34} One process that has been analyzed from both an engineering and economic standpoint is shown in Figure 2.6.

27 Lacker, K. S.; Grimes, P.; Ziock, H.-J., Capturing Carbon Dioxide From Air. In *First National Conference on Carbon Sequestration*, National Energy Technology Laboratory: Washington, DC, 2001.

28 Keith, D. W.; Ha-Duong, M.; Stolaroff, J. K., Climate strategy with CO₂ capture from the air. *Climatic Change* 2006, 74, (1-3), 17-45.

29 Ibid.

30 Zeman, F. S.; Keith, D. W., Carbon neutral hydrocarbons. *Philosophical Transactions of the Royal Society a-Mathematical Physical and Engineering Sciences* 2008, 366, (1882), 3901-3918.

31 Nikulshina, V.; Ayesa, N.; Galvez, M. E., et al., Feasibility of Na-based thermochemical cycles for the capture of CO₂ from air - Thermodynamic and thermogravimetric analyses. *Chemical Engineering Journal* 2008, 140, (1-3), 62-70.

32 Nikulshina, V.; Gálvez, M. E.; Steinfeld, A., Kinetic analysis of the carbonation reactions for the capture of CO₂ from air via the Ca(OH)₂-CaCO₃-CaO solar thermochemical cycle. *Chemical Engineering Journal* 2007, 129, (1-3), 75-83.

33 Baciocchi, R.; Storti, G.; Mazzotti, M., Process design and energy requirements for the capture of carbon dioxide from air. *Chemical Engineering and Processing* 2006, 45, (12), 1047-1058.

34 Zeman, F., Energy and material balance of CO₂ capture from ambient air. *Environmental Science and Technology* 2007, 41, (21), 7558-7563.

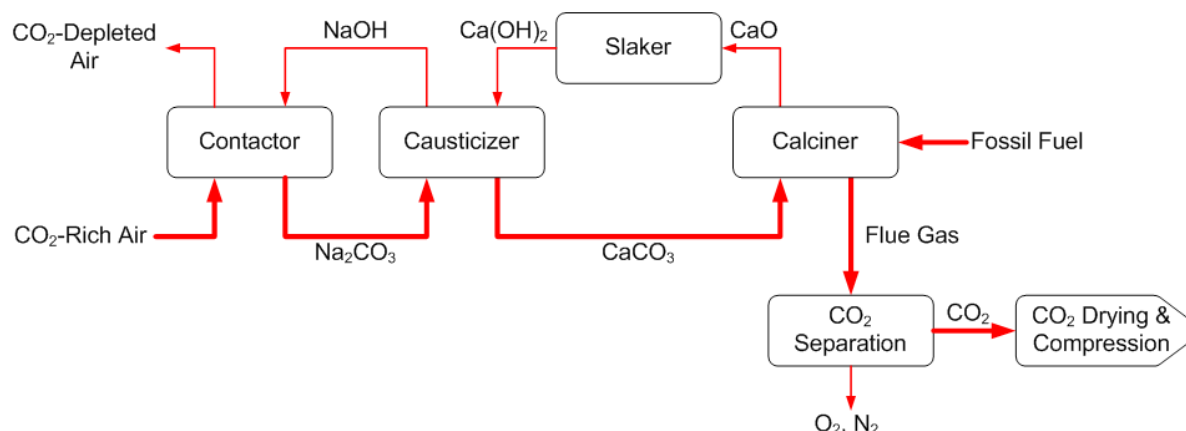


Figure 2.6: The layout of the direct capture system where thick arrows represent flows of carbon in the process.³⁵

In this process, CO₂-rich ambient air is contacted with sodium hydroxide, NaOH, in a spray tower or other appropriate vessel, producing the sodium carbonate, Na₂CO₃.³⁶ The sodium carbonate is then converted to calcium carbonate, CaCO₃, by reaction with calcium hydroxide, Ca(OH)₂. Calcium carbonate is decomposed in a kiln at approximately 900 °C, producing lime (CaO) and gaseous CO₂.³⁷ Flue gas from the kiln can then be treated by a post-combustion capture process using amines or another physical solvent.³⁸ Alternatively, the kiln could be operated in an oxyfuel mode with the addition of air separation to produce oxygen and the removal of CO₂ separation.³⁹

Depending on the design of the contactor and kiln, energy requirements for this process (including compression) appear to be on the order of 2800-4300 kWh per tonne of CO₂.⁴⁰ For comparison, coal, oil, and gas contain approximately 3000, 3800 and 5300 GJ of energy per tonne of CO₂.⁴¹ Based on an economic analysis of the design shown in Figure 2.6, Stolaroff et al. believe the cost of capture (with current technology) to be less than \$250 per tonne CO₂—significantly less than the cost of switching the U.S. transportation infrastructure to hydrogen fuel.⁴²

³⁵ Stolaroff, J. K. Capturing CO₂ from ambient air: a feasibility assessment. Carnegie Mellon University, Pittsburgh, PA, 2006.

³⁶ Stolaroff, J. K.; Keith, D. W.; Lowry, G. V., Carbon Dioxide Capture from Atmospheric Air Using Sodium Hydroxide Spray. *Environmental Science and Technology* 2008, 42, (8), 2728-2735.

³⁷ Zeman, F., Energy and material balance of CO₂ capture from ambient air. *Ibid.* 2007, 41, (21), 7558-7563.

³⁸ Stolaroff, J. K. Capturing CO₂ from ambient air: a feasibility assessment. Carnegie Mellon University, Pittsburgh, PA, 2006.

³⁹ Baciocchi, R.; Storti, G.; Mazzotti, M., Process design and energy requirements for the capture of carbon dioxide from air. *Chemical Engineering and Processing* 2006, 45, (12), 1047-1058.

⁴⁰ Zeman, F., Energy and material balance of CO₂ capture from ambient air. *Environmental Science and Technology* 2007, 41, (21), 7558-7563.

⁴¹ Keith, D. W.; Ha-Duong, M.; Stolaroff, J. K., Climate strategy with CO₂ capture from the air. *Climatic Change* 2006, 74, (1-3), 17-45.

⁴² Stolaroff, J. K. Capturing CO₂ from ambient air: a feasibility assessment. Carnegie Mellon University, Pittsburgh, PA, 2006.



Box 2.3: Building an air capture pilot plant

While use of air capture for CO₂ sequestration is some ways off, several small-scale pilot projects have shown that it is indeed feasible. In 2005, Joshua Stolaroff, David Keith and colleagues constructed a relatively crude air scrubber and showed that absorbing CO₂ from the air using NaOH was feasible. Following this, they designed and constructed the more refined device shown here which showed that the cost of running the absorber is less than 100 kWh per tonne of CO₂.⁴³

Image courtesy David Keith

“Viable air capture technology could be particularly attractive as a strategy for dealing with emissions from small and mobile sources such as automobiles and aircraft.”

2.4 Regulatory Issues Surrounding CO₂ Capture

Operation of CO₂ capture facilities will present risks of similar magnitude and likelihood to human health and the local environment as operation of traditional power generation facilities and other industrial facilities. Regulatory frameworks exist today in most developed nations that are sufficient to address these risks and handle the siting of capture facilities.⁴⁴ However, there are issues that must be resolved in accounting for emissions reductions considering the energy penalty associated with capture—these issues are discussed in Chapter 10.

There is also considerable discussion surrounding the concept of “capture-ready” power plants. The MIT Future of Coal study defined a plant as being capture-ready “if, at some point in the future it can be retrofitted for carbon capture and sequestration and still be economical to operate.”⁴⁵ However, as discussed by Bohm and colleagues, the concept of capture ready is more than just a specific plant design—it is a spectrum of decisions that a plant operator must make during plant design.⁴⁶ This recent analysis suggests that there is currently little incentive to build capture-ready facilities if there is significant up-front cost to do so. Moreover, appropriate siting of the facility in relation to power (or other product) demand centers will likely be more important than distance to a CO₂ sequestration opportunity.⁴⁷

43 Mahmoudkhani, M; Keith, D.W. Low-energy sodium hydroxide recovery for CO₂ capture from air. *International Journal of Greenhouse Gas Control*, 2008, submitted.

44 Zakkour, P; Haines, M., Permitting issues for CO₂ capture, transport and geological storage: A review of Europe, USA, Canada and Australia. *International Journal of Greenhouse Gas Control* 2007, 1, (1), 94-100.

45 MIT *The Future of Coal*; Massachusetts Institute of Technology: Boston, MA, 2007.

46 Bohm, M. C.; Herzog, H. J.; Parsons, J. E., et al., Capture-ready coal plants—Options, technologies and economics. *International Journal of Greenhouse Gas Control* 2007, 1, (1), 113-120.

47 Newcomer, A.; Apt, J., Implications of generator siting for CO₂ pipeline infrastructure. *Energy Policy* 2008, 36, (5), 1776-1787.

Chapter 3: Transporting CO₂ From Sources To Sequestration Sites

It is likely that most early CCS projects will inject CO₂ from sources that are located adjacent or very close to the injection site. However, as the scale of CCS activities grow, it will become necessary to build pipeline infrastructure to move large volumes of CO₂ from facilities where it is being captured to appropriate sequestration sites.

From an operational perspective, pipeline diameters are sized according to operating parameters so that CO₂ remains supercritical fluid (Figure 3.1) throughout transport.¹ CO₂ pipeline diameters vary, but generally larger diameters of pipe result in lower transportation costs.²

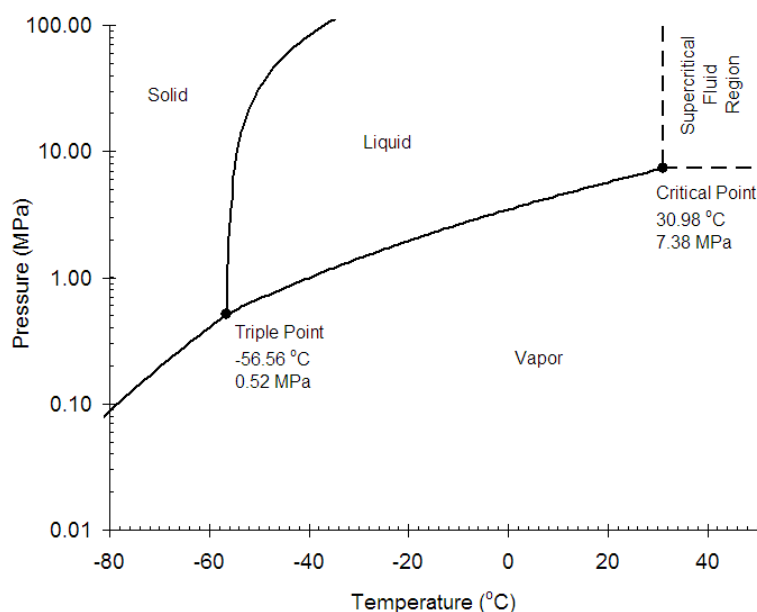


Figure 3.1: Pressure-temperature phase diagram for carbon dioxide (CO₂).

If CCS is widely deployed, the required CO₂ pipeline infrastructure could be very large. “Plausible capture rates (~80%) of the carbon dioxide from fossil fuels used for electric power production in the U.S. today would produce a CO₂ stream of approximately 1,800 million tonnes (Mt) per year injected into a variety of geological formations.”³ The existing U.S. CO₂ pipeline infrastructure, shown in Figure 3.2, transports 45 Mt of CO₂ per year over

¹ Recht, D. L., Design Considerations for Carbon-Dioxide Pipe Lines. 1. *Pipe Line Industry* 1984, 61, (3), 53-54.

² McCoy, S. T.; Rubin, E. S., An engineering-economic model of pipeline transport of CO₂ with application to carbon capture and storage. *International Journal of Greenhouse Gas Control* 2008, 2, (2), 219-229.

³ Newcomer, A.; Apt, J., Implications of generator siting for CO₂ pipeline infrastructure. *Energy Policy* 2008, 36, (5), 1776-1787.

3,500 miles of pipe for enhanced oil recovery (EOR).⁴ For comparison, the existing U.S. natural gas pipeline network transports 455 Mt per year of natural gas over 300,000 miles of interstate and intrastate pipe.⁵

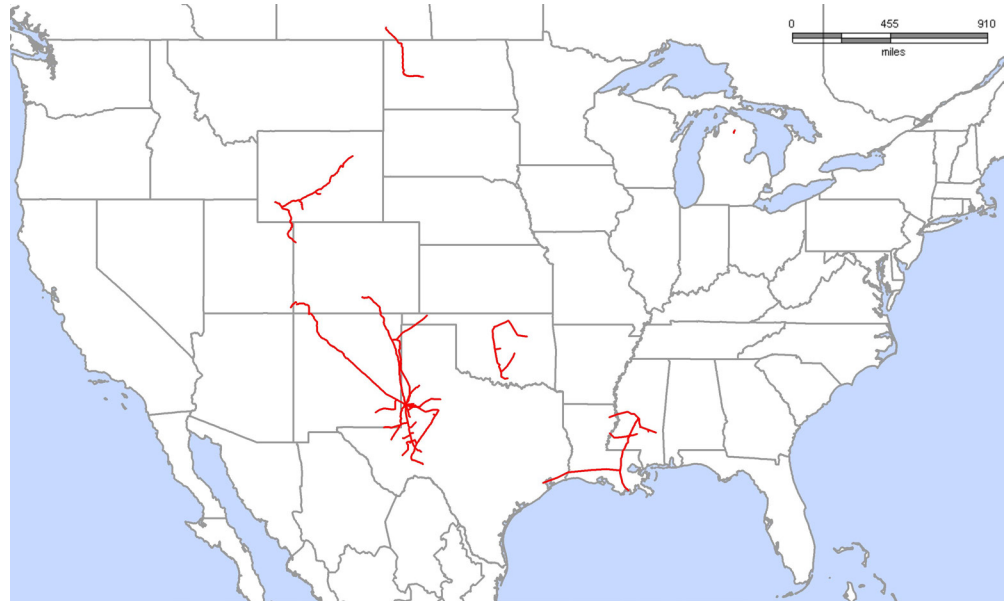


Figure 3.2: The existing U.S. CO₂ pipeline infrastructure as of mid-2008, from Ventyx Inc. Velocity Suite (www.ventyx.com).

“... some estimates predict that the CO₂ pipeline network that will develop for CCS could be as large as the existing natural gas infrastructure.”

At the high-end, some estimates predict that the CO₂ pipeline network that will develop for CCS could be as large as the existing natural gas infrastructure. However, other estimates predict that the shorter transportation distances for CO₂ as compared to natural gas will likely result in a smaller network.⁶ It appears that CCS will not drastically alter current siting calculations for electricity generation units, as “[t]he cost of piping CO₂ is not negligible, but much less than [electric] transmission cost,” which implies that the size of the infrastructure may be larger rather than smaller.⁷

In any case, in a world with CCS, it is almost certain that there will be an increase in the amount of CO₂ transported by pipeline and the size of the CO₂ pipeline infrastructure. Consequently, in the following chapter we examine the current regulatory structure to assess whether it presents barriers to development of future CO₂ transport infrastructure.

4 *Coal: A Clean Future*, Hearing Before S. Subcomm. on Energy of the Comm. on Finance, 110th Cong. (2007) (Statement of Bill Townsend, CEO, Blue Source). See also, 2008 Oil & Gas Journal Worldwide EOR Survey. The survey reports that 240,313 bbl/d is currently produced via CO₂-flood EOR and the amount of CO₂ delivered into Texas is 27 Mt/y. The number may be closer to 32 Mt/y of CO₂ considering that the typical net utilization of CO₂ falls somewhere between 5 to 7 mscf/bbl, equal to 23 to 32 Mt/y of CO₂.

5 *Newcomer & Apt* at 22. (“while the total mass of CO₂ is 4 times larger than the mass of current natural gas transport (455 Mt), that does not mean that the total pipeline infrastructure will be 4 times larger, since at operational conditions, a CO₂ pipeline carries about 3 times more mass per unit of length than does a natural gas pipeline”).

6 Parfomak, P. W.; Fogler, P. *Carbon Dioxide (CO₂) Pipelines for Carbon Sequestration: Emerging Policy Issues*; Congressional Research Service: Washington, DC, 2007.

7 *Newcomer & Apt* at 7.

3.1 Current Federal Regulation of CO₂ Pipelines

The current federal regulatory framework for CO₂ pipeline rate and access regulation can only be described as byzantine:

- The Federal Energy Regulatory Commission (FERC) has disclaimed jurisdiction over CO₂ pipelines under the Natural Gas Act.
- The Surface Transportation Board (STB) has not opined on its jurisdiction over CO₂ pipelines under Title 49, United States Code.
- The Interstate Commerce Commission (ICC) (the predecessor of the STB) disclaimed jurisdiction because CO₂ is a “gas” and, therefore, exempt under Title 49, United States Code.
- The Bureau of Land Management (BLM) has imposed the equivalent of a common carrier obligation on CO₂ pipelines crossing Federal lands on the ground that CO₂ is “natural gas.”

Federal Energy Regulatory Commission: FERC possesses jurisdiction to regulate transportation and sale at wholesale of natural gas in interstate commerce under the Natural Gas Act (NGA).⁸ A pipeline operator cannot engage in the transportation or sale of natural gas, or service, construct, extend, or acquire a natural gas pipeline without obtaining a certificate of public convenience and necessity from FERC.⁹ The Commission will issue a certificate only if “required by the present or future public convenience and necessity.”¹⁰ FERC can impose conditions on the certificate¹¹ and has the power to determine the service area to be covered.¹² Perhaps the most valuable tool in the NGA is the right of eminent domain granted to the holder of a certificate of public convenience and necessity.¹³ These provisions from Section 7 of the NGA, combined with Section 4 (rates and charges) and Section 5 (fixing rates and charges), have led the courts to repeatedly interpret the NGA as providing for exclusive and preemptive federal siting of interstate natural gas pipelines.¹⁴

“The current federal regulatory framework for CO₂ pipeline rate and access regulation can only be described as byzantine.”

⁸ Section 1(b) of the Natural Gas Act, 15 U.S.C. §717(b) (2006), defines the Act's scope:

The provisions of this chapter shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale . . . but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.

The FERC's core activities under the NGA include: (1) certification of jurisdictional pipeline and storage facilities (certification carries eminent domain authority); (2) regulation of rates, terms and conditions for pipeline transportation and storage; and (3) oversight of wholesale sales for resale (although wholesale rates are largely deregulated).

⁹ *Id.* § 717f(c)(1)(A).

¹⁰ *Id.* § 717f(e).

¹¹ *Id.* If the holder and a property owner cannot agree to the terms of a right-of-way for the construction, operation, maintenance, or transportation of a natural gas pipeline, the holder “may acquire the same by the exercise of the right of eminent domain” in state or federal court.

¹² *Id.* § 717f(f).

¹³ *Id.* § 717f(e).

¹⁴ See e.g., *Northern Natural Gas Co. v. Iowa Util. Bd.*, 377 F.3d 817 (8th Cir. 2004) (finding that federal regulations and the NGA occupy the field of extension, operation, and acquisition of natural gas facilities, thereby preempting any state authority to do so.); see also *Schneidewind v. ANR Pipeline Company*, 485 U.S. 293 (1988) (the NGA preempts state attempts to regulate securities issued by interstate pipeline companies). A certificate does not have preemptive effect when a state is exercising federal delegated authority, such as that provided by the Clean Water Act. In such situations, the question is not one of preemption, but of which statute prevails.

*“...FERC
has...specifically
disclaimed
jurisdiction over
CO₂ pipelines...”*

In addition to regulating natural gas pipelines, FERC also regulates oil pipelines under the Interstate Commerce Act.¹⁵ The Commission’s responsibilities include: (1) regulation of rates and practices of oil pipeline companies engaged in interstate transportation; (2) establishment of nondiscriminatory conditions of service in order to provide shippers access to pipeline transportation; and (3) establishment of reasonable rates for transporting petroleum and petroleum products by pipeline.

FERC has, however, specifically disclaimed jurisdiction over CO₂ pipelines, even where they transport small amounts of natural gas, such that NGA requirements on rate regulation, access regulation, and certificate requirements applicable to interstate natural gas pipelines do not apply. In *Cortez Pipeline Co. (Cortez)*, FERC found that it did not have jurisdiction over CO₂ pipelines under the NGA.¹⁶ Cortez sought to develop a pipeline connecting a CO₂ reservoir in Colorado with oil fields in Texas for EOR. Cortez requested that FERC issue a declaratory order stating that FERC did not have jurisdiction over the proposed pipeline because the supercritical fluid being transported was not “natural gas” within the meaning of the NGA. (The NGA defines natural gas as “natural gas unmixed or any mixture of natural and artificial gases.”) The pipeline company stated that the mixture transported in the pipeline project would be 98% CO₂, with the other 2% of mixed composition, including methane.¹⁷

In response to the request, FERC analyzed the NGA to determine whether the CO₂ and methane gas mixture was “natural gas” within the meaning of the statute. FERC looked beyond a scientific or technical definition of “natural gas” to determine its jurisdiction, and instead looked to the reasons for the passage of the NGA. FERC noted a lack of debate over any ambiguity in the term “natural gas” during NGA enactment. FERC determined that the only debate in the legislative history around the term “natural gas” in the NGA focused on whether unmixed artificial gas should be included in the definition, concluding that, “[i]t seems likely that Congress used the common meaning of ‘natural gas’ of a mixture of gases, including a sufficient component of hydrocarbons to give it heating value.”¹⁸

After FERC determined that there was no specific chemical composition under the NGA that constitutes “natural gas,” FERC evaluated Congress’ objectives in enacting the NGA. FERC stated that the “goal of the NGA was to protect the consumers of a salable commodity from ‘exploitation at the hands of the natural gas companies’ and was framed to afford consumers a bond of protection from excessive rates and charges.”¹⁹

¹⁵ 49 U.S.C. § 60502 (2006).

¹⁶ 7 FERC ¶ 61,024 (1979).

¹⁷ In the CCS context, it is unlikely that methane will be mixed with any CO₂, so there is likely to be less of a question under the Natural Gas Act.

¹⁸ *Id.* at 61,041.

¹⁹ *Id.* at 61,042.

FERC considered whether to include the CO₂ pipeline within its jurisdiction “in light of the general goal of the NGA,” and found that “no goal or purpose of the NGA” would be advanced by FERC jurisdiction over the CO₂ pipeline,²⁰ and accordingly did not assert jurisdiction.

Surface Transportation Board: The STB is an independent federal administrative agency within the Department of Transportation and is responsible for economic regulation of certain common carrier interstate transportation. This responsibility primarily relates to railroad transportation, but also includes interstate transportation by pipeline of commodities “when transporting a commodity other than water, gas or oil,” with the term “gas” undefined.²¹

The ICC, the STB’s predecessor, specifically disclaimed jurisdiction over CO₂ pipelines in 1981. In an ICC proceeding involving the same pipeline project as the FERC decision, *Cortez Pipeline Co.*, the ICC determined that it lacked jurisdiction over CO₂ pipelines. Cortez filed a petition with the ICC for a declaratory order that CO₂ pipeline transport is exempt from ICC jurisdiction.²² Cortez argued that the Interstate Commerce Act (ICA) specifically excluded from ICC jurisdiction interstate pipeline transportation of “water, gas, or oil,” and that CO₂, while transported as a supercritical fluid, is a gas at atmospheric pressure, the transportation of which falls within the statutory exemption from regulation.

The ICC proceeded to analyze the situation in terms of the meaning of “gas” in the statutory exemption. The inquiry began with the history of the statute granting jurisdiction over common carrier pipelines to the ICC, the Hepburn Act of 1906.²³ The ICC found that the original language in the Hepburn Act provided ICC jurisdiction over interstate commodity transportation “except water and except natural or artificial gas.” “Artificial” coal gas was still in use during the early 1900’s, so legislators wrote the exemption from jurisdiction to be clear that both “natural or artificial gas” are exempt from ICC jurisdiction. The term “natural or artificial” was eliminated in a 1978 recodification because “those words were considered surplus.”²⁴ The ICC determined that the recodification of the law, which earlier removed the original description of gas as “natural or artificial,” was not a substantive change.

The ICC issued a preliminary finding that it lacked jurisdiction over CO₂ pipelines stating that, “[t]he plain meaning of the former act [Hepburn Act of 1906], as supported by the legislative history, is that the universe of gas types classified by origin or source was excluded.”²⁵ The ICC explained that the

“... the STB’s predecessor specifically disclaimed jurisdiction over CO₂ pipelines in 1981.”

²⁰ *Id.*

²¹ 49 U.S.C. §15301(a) (2006).

²² *Cortez Pipeline Co.*, 45 Fed. Reg. 85177 (1980). The ICC also ruled in the same order on a similar petition filed by the Atlantic Richfield Company, who sought, like the Cortez Pipeline Co., to transport CO₂ via pipeline from Colorado to Texas for tertiary recovery through EOR. See n.1.

²³ Pub. L. No. 59-337, 34 Stat. 584.

²⁴ 45 Fed. Reg. 85177; see also H.R. Rep. No. 95-1395, at 52 (1978), reprinted in 1978 U.S.C.A.A.N. 3009, 3061.

²⁵ *Id.*

“The GAO [has] released a report that...found that CO₂ pipelines are within the oversight authority of the STB.”

decision of FERC, as a “sister agency, should be given weight if possible.”²⁶ However, the ICC distinguished FERC’s decision, because it was not based on an interpretation of the term “natural and artificial gas.”

After receiving only supportive public comments on its preliminary decision, the ICC affirmed the preliminary decision that it did not possess jurisdiction over CO₂ pipelines.²⁷ The ICC found that based on the plain meaning of the statutory exemption for “water, gas or oil,”²⁸ and the legislative history of the Hepburn Act of 1906, “all types of gas classified by origin or source are excluded from our jurisdiction. Consequently, carbon dioxide gas, the subject of the petitions, is also excluded, when transported by pipeline.”²⁹

The General Accounting Office (GAO) subsequently released a report that specifically found that CO₂ pipelines are within the oversight authority of the STB, along with at least one other gas, hydrogen.³⁰ To date, the STB (established in 1995) has not heard any case specifically requesting it to rule on its jurisdiction over CO₂ pipelines, and on that basis has declined to address the jurisdictional issue raised in the GAO report.³¹

While the STB is not bound by the ICC ruling,³² the statutory language that was interpreted in the ICC’s *Cortez* decision is virtually identical to that in the corresponding section of the current Interstate Commerce Commission Termination Act (ICCTA).³³ Given the ICC’s status as a predecessor agency and the similarity in statutory language, STB may be inclined to follow the ICC *Cortez* decision with respect to jurisdiction over CO₂ pipelines. Whether such a decision could be sustained on judicial review remains to be seen. The ICC’s review of the legislative history of the 1906 Hepburn Act, in the underlying decision, fails to support its conclusion that all gases, rather than combustible gases, were intended to be covered.

Even if one assumes that the STB has jurisdiction over CO₂ pipelines, the STB’s regulatory oversight would be limited. The STB’s regulatory role is to ensure that a common carrier pipeline: (1) charges reasonable, non-discriminatory rates;³⁴ (2) establishes classifications, rules and practices on matters related to its transportation and service;³⁵ (3) does not subject its

26 *Id.* (citing *Erlenbaugh v. U.S.*, 409 U.S. 239, 243-44 (1972)).

27 *Cortez Pipeline Co.*, 46 Fed. Reg. 18805 (1981).

28 49 U.S.C. 10501(a)(1)(C) (2006).

29 *Cortez Pipeline Co.*, 46 Fed. Reg. 18805. While the case indicated that the gas was transported as a supercritical fluid, the decision treats CO₂ as a gas at atmospheric pressure.

30 Testimony and Statement for the Record by Phyllis F. Scheinberg before the Subcommittee on Surface Transp. And Merchant Marine Infrastructure Safety and Security, U.S. Senate, *Issues Associated with Pipeline Regulation by the Surface Transportation Board*, Gov’t Accountability Office, GAO/RCED-98-99, Appendix 1, Pipelines and Commodities Under STB’s Jurisdiction (April 1998) (“GAO Report”).

31 Vann, Adam and Paul W. Parfomak, *Regulation of Carbon Dioxide (CO₂) Sequestration Pipelines: Jurisdictional Issues*, at n.29, Congressional Research Service (Jan. 2008).

32 Under U.S. administrative law, an agency is free to change its interpretation of the statute it administers if there is a reasoned basis for its decision. *See Chevron v. Nat. Resources Defense Council*, 467 U.S. 837, 863 (1984); *Motor Vehicles Mfg. Assoc. v. State Farm*, 463 U.S. 29, 42 (1983).

33 Compare 49 U.S.C. §15301(a) (2006) with prior 49 U.S.C. § 10501(a)(1)(C) (1978).

34 49 U.S.C. §15501(a) (2006).

35 49 U.S.C. §15502 (2006).

shippers to unreasonable discrimination;³⁶ (4) provides proper facilities for the interchange of traffic;³⁷ and (5) provides transportation and service, as well as rates and other terms of service, upon reasonable request.³⁸ Importantly, the STB authority, unlike FERC authority under the NGA, does not encompass siting, certification, or eminent domain authority with respect to pipelines it regulates.

Moreover, even if the STB exercised regulatory authority over CO₂ pipelines, its jurisdiction over a particular pipeline would depend upon whether the pipeline company is a “pipeline carrier.”³⁹ The ICCTA defines “pipeline carrier” as a “person providing pipeline transportation for compensation.”⁴⁰ If the company entered into transactions with other companies to ship their carbon dioxide in interstate commerce, then the company would be a “pipeline carrier” and subject to STB regulation (assuming, again, that the STB found that supercritical CO₂ is not an exempt gas). In addition, according to the precedent established pursuant to the ICA, a pipeline that does not engage in “transportation” is not subject to regulation. For example, if a company owned or operated pipelines in which it shipped only CO₂ it had produced, it would not be engaged in interstate “transportation” within the meaning of Title 49.⁴¹ This precedent is consistent with the ICCTA definition of a “pipeline carrier,” and would seem to indicate that if a CO₂ capturer owns the pipelines that transport only CO₂ it produces from its own facilities, it would not be regulated under Title 49.

If jurisdiction attaches, the STB’s regulatory authority over pipeline carriers is significantly less rigorous and intrusive than FERC’s regulatory authority over natural gas pipelines. For example, the STB may not begin an investigation into a pipeline’s rates on its own initiative. Instead, the STB may begin investigations only in response to complaints by shippers or other affected parties.⁴² In addition, the ICCTA eliminated the requirement that pipeline carriers file their rates, and, under the current regulatory scheme, the STB has no authority to regulate a pipeline carrier’s decision to enter or abandon markets.⁴³

Bureau of Land Management: Federal agencies have authority to grant rights-of-way (ROW) across federal lands. The statutes governing ROW are important both because they establish the ground rules for siting pipelines across federal lands, and because they may establish access and rate conditions

“[If it has jurisdiction] the STB’s regulatory authority over pipeline carriers is significantly less rigorous and intrusive than FERC’s regulatory authority over natural gas pipelines.”

36 49 U.S.C. §15505 (2006).

37 49 U.S.C. §15506 (2006).

38 49 U.S.C. §15701 (2006); 49 C.F.R. §§1305.2 – 1305.3 (2006).

39 See e.g., 49 U.S.C. §15501 (2006) (setting forth standards for pipeline rates, classifications, and rules for transportation or service provided by a “pipeline carrier.”).

40 49 U.S.C. §15102(2) (2006).

41 See *U.S. v. Champlin Refining Co.*, 341 U.S. 290 (1951) (holding that the ICC could not regulate an oil company that transports its own products through its own pipeline, does not hold itself out as a public carrier, and does not transport products of any other company). See also *The Pipe Line Cases*, 234 U.S. 548, 562 (1914) (holding that the use of an oil pipeline for the sole purpose of moving oil across a state line from a company’s own wells to its own refinery is not “transportation” within the meaning of the ICA).

42 49 U.S.C. § 15503(c) (2006).

43 GAO Report at 7.

for service provided on pipelines that cross federal lands. The Bureau of Land Management has responsibility for administering ROW on federal lands managed by the Department of the Interior. The Mineral Leasing Act (MLA) provides that:

Rights-of-way through any Federal lands may be granted by the Secretary of the Interior or appropriate agency head for pipeline purposes for the transportation of oil, natural gas, synthetic liquid or gaseous fuels, or any refined product produced therefrom . . . ⁴⁴

If a right-of-way is granted under the MLA, the pipeline is regulated by FERC as a common carrier, which imposes an obligation on the pipeline to “accept, convey, transport, or purchase without discrimination all oil or gas delivered to the pipeline without regard to whether such oil and gas was produced on Federal or non-Federal lands.”⁴⁵

In contrast, the Federal Land Policy and Management Act (FLPMA) provides that the Secretary shall issue ROW for:

pipelines and other systems for the transportation or distribution of liquids and gases, *other than water and other than oil, natural gas, synthetic liquid or gaseous fuels, or any refined product produced therefrom*, and for storage and terminal facilities in connection therewith;⁴⁶

FLPMA rights-of-way, in contrast to MLA rights-of-way, do not require that the operator act as a common carrier.⁴⁷

Questions regarding which statute controls have been the subject of litigation. In the case of *Exxon Corp. v. Lujan*,⁴⁸ Exxon challenged the issuance of a ROW across federal lands under the MLA, instead arguing that the ROW should have been issued under the FLPMA.⁴⁹ The reason that this distinction is important is that the MLA imposes common carrier obligations on pipeline operators, while the FLPMA does not. Exxon challenged the ROW at the agency and district court level, arguing that CO₂ is not a “natural gas” within the meaning of the MLA, but rather falls within the purview of FLPMA.

The court addressed this statutory interpretation question by reference to the well-known administrative law precedent in *Chevron, U.S.A., Inc. v. Natural Resources Defense Council*,⁵⁰ under which courts defer to an agency’s

⁴⁴ 30 U.S.C. § 185(a) (2006).

⁴⁵ *Id.* at § 185(r).

⁴⁶ 43 U.S.C. § 1761(a)(2) (2006) (emphasis added).

⁴⁷ *Id.* at § 1761(b). An application for a ROW must contain information about the “effect on competition,” which is considered in the terms and conditions of the grant of a ROW, but there are no specific non-discrimination or open access requirements.

⁴⁸ 970 F.2d 757 (10th Cir. 1992).

⁴⁹ 43 U.S.C. § 1761 (2006).

⁵⁰ 467 U.S. 837 (1984).

interpretation of a statute it implements where the statute is ambiguous and the agency interpretation is reasonable. The Tenth Circuit noted that there are varying definitions of natural gas, and that courts and agencies have interpreted the meaning of natural gas in different contexts, including in the FERC *Cortez* case. The court concluded that the statutory term “natural gas” was ambiguous. It looked further to the legislative history of the MLA, but concluded that “the legislative history of the MLA does not establish Congress’s intention with the requisite clarity.”⁵¹ Consequently, the court applied the *Chevron* doctrine and granted deference to the Bureau of Land Management’s reasonable interpretation of the MLA to cover ROW for CO₂ pipelines, based on an interpretation that CO₂ was “natural gas” under the MLA.

In summary, the uncertainty over which Federal agency has responsibility for rate and access regulation and how the agency would regulate rates and access for CO₂ presents a barrier to construction of large-scale CO₂ pipeline network.

3.2 Federal Regulation of Pipeline Safety

Careful considerations should be given to safety issues that may arise in connection with operation of CO₂ pipelines. While CO₂ is heavier than air, and can pose dangers if it collects in basements or low lying areas, it is not-flammable and does not present the magnitude of risk that heavier-than-air combustible gases such as propane pose. The current pipeline safety regime is clearly applicable to CO₂ pipelines and does not suffer from the same uncertainties as economic regulation of those pipelines. The U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (PHMSA) has primary authority to regulate interstate CO₂ pipelines under the Hazardous Liquid Pipeline Act of 1979.⁵² Within PHMSA, the Office of Pipeline Safety (OPS) regulates the design, construction, operation, maintenance, and spill response planning for regulated pipelines.⁵³ PHMSA establishes minimum safety standards for interstate pipelines, and has largely preempted states from establishing their own standards for interstate pipelines.⁵⁴

Carbon dioxide is listed as a non-flammable gas hazardous material under Department of Transportation regulations.⁵⁵ As a result of this classification, safety of CO₂ pipelines is regulated to the same degree that hazardous liquids pipelines are.⁵⁶

Leakage and other releases from CO₂ pipelines also present regulatory accounting issues under cap-and-trade programs. These issues are discussed in Chapter 10.

⁵¹ *Exxon Corp. v. Lujan*, 970 F.2d 757, 761 (10th Cir. 1992).

⁵² 49 U.S.C. § 601 (2006).

⁵³ 49 C.F.R. §§ 190, 195-199 (2008).

⁵⁴ 49 U.S.C. § 60104(c) (2006) (generally, states and local authorities “may not adopt or continue in force safety standards for interstate pipeline facilities or interstate pipeline transportation.”); *Olympic Pipeline Co. v. City of Seattle*, 437 F.3d 872 (9th Cir. 2006) (finding that safety regulations imposed in addition to federal-state pipeline safety agreement were preempted by the Federal Pipeline Safety Act.).

⁵⁵ 49 C.F.R. § 172.101 (2008).

⁵⁶ 49 C.F.R. § 195 (2008).

“The current pipeline safety regime is clearly applicable to CO₂ pipelines and does not suffer from the same uncertainties as economic regulation of those pipelines.”

3.3 Regulation in Selected States: Texas and New Mexico

CO₂ pipelines may be subject to state regulation as well as federal regulation. While we did not attempt to survey state regulatory authorities and practices in 50 states, we did review the regulations in Texas and New Mexico as examples of state approaches.

Rate Regulation: In Texas, CO₂ pipelines have the option to choose to become a common carrier,⁵⁷ which, in return for certain rights, imposes certain obligations on the pipeline. A CO₂ pipeline regulated as a common carrier is required to charge equal rates for like service,⁵⁸ and to “make and publish their tariffs under rules proscribed by the [Texas Railroad Commission].”⁵⁹ The Texas Railroad Commission does not appear to prescribe detailed tariff provisions for CO₂ pipelines, as it does for petroleum pipelines.⁶⁰ New Mexico regulates the rates of oil or oil products pipelines; it does not currently regulate the rates of CO₂ pipelines.⁶¹

Safety: As noted above, the OPS regulates interstate pipelines, but states can participate in safety regulation as well.

The states that have CO₂ pipelines regulate the safety of CO₂ pipelines to varying degrees under delegation of Hazardous Liquid Pipeline Act (HPLA) authority. First, states can assume regulatory authority and responsibility for enforcement of HPLA requirements for intrastate pipelines through certification, whereby states adopt minimum federal standards and make an annual certification to OPS.⁶² Second, states can enter into agreements with OPS to oversee aspects of the safety of intrastate pipelines. Third, states can act as agents of OPS with respect to interstate pipelines, such that the state participates in oversight of interstate pipelines but OPS is responsible for the ultimate enforcement in the event of violations.⁶³

The Safety Division of the Texas Railroad Commission is certified by OPS to regulate the safety of CO₂ pipelines that are used for intrastate pipeline transportation of CO₂.⁶⁴ Regulation includes reporting requirements, integrity assessment and management plans, notification requirements, and periodic inspection.⁶⁵ In addition, the Texas Administrative Code includes a subchapter that includes provisions applicable to hazardous liquids and CO₂ pipelines

57 TX NAT. RES. CODE ANN. § 111.002 (2008) (“A person is a common carrier subject to the provisions of this chapter if it: (6) owns, operates, or manages, wholly or partially, pipelines for the transportation of carbon dioxide or hydrogen in whatever form to or for the public for hire, but only if such person files with the commission a written acceptance of the provisions of this chapter expressly agreeing that, in consideration of the rights acquired, it becomes a common carrier subject to the duties and obligations conferred or imposed by this chapter.”).

58 TX NAT. RES. CODE ANN. § 111.017 (2008).

59 TX NAT. RES. CODE ANN. § 111.014 (2008).

60 See 16.3.71 TX Administrative Code (2008).

61 NM STAT. ANN. § 70-3-1 (2008) (“The corporation commission [public regulation commission] may prescribe reasonable maximum rates for the transportation of oil and the products derived therefrom, where such products are transported by a pipeline common carrier from any point in New Mexico to an ultimate destination in New Mexico, provided, in the event the reasonableness of such rates are [is] contested in the manner provided by law, the burden of proof to show the unreasonableness of such rates shall be upon the person, firm, association or corporation contesting the same.”). The New Mexico Constitution grants the New Mexico Public Regulation the authority and responsibility to regulate “pipeline companies . . . in such manner as the legislature shall provide.” NM Const. Art. XI, § 2.

62 49 U.S.C. § 60105 (2006).

63 49 U.S.C. § 60106 (2006).

64 TEX. ECON. REG. CODE ANN. § 8.1 *et seq.* (2008).

65 *Id.*

only. This section includes reporting requirements, corrosion control measures, and public education measures.⁶⁶

Similarly, New Mexico has a Pipeline Safety Bureau that conducts compliance inspections and investigates accidents involving intrastate CO₂ pipelines. The New Mexico Pipeline Safety Bureau entered into an agreement with DOT whereby the OPS oversees certain aspects of its intrastate hazardous liquids pipelines. New Mexico also has an informational filing requirement specifically addressing CO₂ pipelines.⁶⁷

Siting Authority and Eminent Domain: As a general matter, the states and not the federal government are responsible for siting both interstate and intrastate CO₂ pipelines. In the states reviewed, CO₂ pipelines have eminent domain authority, which facilitates the ability to site the pipelines there. The power of eminent domain allows pipeline developers to take lands for the public use of pipeline infrastructure development. Lands for pipeline construction are often obtained through leases, with the threat of eminent domain action looming over the transactions.

In Texas, pipelines that are common carriers, including CO₂ pipelines, have the statutory right of eminent domain.⁶⁸ The Texas Natural Resources Code provides that:

- (a) Common carriers have the right and power of eminent domain.
- (b) In the exercise of the power of eminent domain granted under the provisions of Subsection (a) of this section, a common carrier may enter on and condemn the land, rights-of-way, easements, and property of any person or corporation necessary for the construction, maintenance, or operation of the common carrier pipeline.⁶⁹

In the exercise of the power of eminent domain, property owners are entitled to just and adequate compensation for the public use of their land. The standard easement granted is 50 feet wide.⁷⁰ Of note, Texas does not require CO₂ pipeline operators to obtain a certificate of need and public convenience before the power of eminent domain is granted.⁷¹ The pipeline operator, not the

“... Texas pipelines that are common carriers, including CO₂ pipelines, have the statutory right of eminent domain.”

⁶⁶ *Id.*

⁶⁷ N.M. CODE R., § 18.60.3.10 (2008).

⁶⁸ TX NAT. RES. CODE ANN § 111.002 (2008). The statute states:

A person is a common carrier subject to the provisions of this chapter if it: (6) owns, operates, or manages, wholly or partially, pipelines for the transportation of carbon dioxide or hydrogen in whatever form to or for the public for hire, but only if such person files with the commission a written acceptance of the provisions of this chapter expressly agreeing that, in consideration of the rights acquired, it becomes a common carrier subject to the duties and obligations conferred or imposed by this chapter..

⁶⁹ TX NAT. RES. CODE ANN § 111.019 (2008).

⁷⁰ TX NAT. RES. CODE ANN § 111.0194 (2008).

⁷¹ The Texas statute lists seven categories of common carrier pipelines. TX NAT. RES. CODE ANN § 111.002 (2008). Of those categories, only common carrier pipelines that transport coal require a certificate of public convenience. TX NAT. RES. CODE ANN §§ 111.301–111.302 (2008). Common carrier pipelines that transport CO₂ do not require such a certificate.

“Large-scale, commercial implementation of CCS... may require further delineation of a CO₂ pipeline transportation regulatory regime.”

state, decides the route a pipeline takes.⁷² The Safety Division of the Railroad Commission of Texas oversees pipeline construction and grants permits for operations of intrastate hazardous liquids pipelines.

Like Texas, New Mexico’s eminent domain statute provides for the authority to condemn surface property for pipeline construction and specifically includes CO₂ pipelines. The New Mexico eminent domain statute allows any person, firm, association or corporation to obtain a right-of-way for the construction, maintenance and operation of such pipelines and to enter onto state and private lands to make necessary surveys and examinations for them.⁷³

This right applies to trunk lines only, which are primary transportation lines. In New Mexico, a pipeline does not have to be a common carrier in order to exercise eminent domain authority.⁷⁴ New Mexico has extensive procedural requirements in place for eminent domain proceedings.⁷⁵ Should dispute arise over condemned property, New Mexico will allow the condemnor to take possession if it can show that the property condemned is for public use.⁷⁶ Condemnation for the provision for CO₂ pipelines is considered “public use” based on the legislature’s decision to grant such pipelines eminent domain authority.⁷⁷

3.4 Adequacy of Existing Law

Large-scale, commercial implementation of CCS will not only require further development of capture and sequestration technology, but may require further delineation of a CO₂ pipeline transportation regulatory regime. Such regulatory development can assure access to eminent domain to facilitate pipeline construction, and provide increased regulatory certainty for CO₂ pipeline infrastructure developers that will be necessary for widespread deployment of CCS.

Rate Regulation: To date, disputes about CO₂ transportation rates have not arisen. However, as the network expands, CO₂ transportation rates could become a contentious issue. While an argument can be made that the STB

⁷² The common carrier statute is void of any discussion concerning the regulation of common carrier pipelines apart from coal pipelines. *See id.* In FAQ’s issued by the Texas Railroad Commission (RRC), the RRC disclaims any authority to decide the route a common carrier pipeline will take and asserts that the authority is vested with the pipeline’s owner or operator. RRC: Pipeline Eminent Domain and Condemnation – FAQ’s, *available at* <http://www.rrc.state.tx.us/eminentdomain.html>.

⁷³ NM STAT. ANN. § 70-3-5(a) (2008) (emphasis added).

⁷⁴ NM STAT. ANN. § 70-3-5(b) (2008). The statute states:

Any person, firm, association or corporation may exercise the right of eminent domain to take and acquire the necessary right-of-way for the construction, maintenance and operation of pipelines, including microwave systems and structures and other necessary facilities for the purpose of conveyance of petroleum, natural gas, *carbon dioxide gas* and the products derived therefrom, but any such right-of-way shall in all cases be so located as to do the least damage to private or public property consistent with proper use and economical construction. Such land and right-of-way shall be acquired in the manner provided by the Eminent Domain Code [42A-1-1 NMSA 1978]. Pursuant to the requirements of Sections 42A-1-8 through 42A-1-12 NMSA 1978, the engineers, surveyors and other employees of such person, firm, association or corporation shall have the right to enter upon the lands and property of the state and of private persons and of private and public corporations for the purpose of making necessary surveys and examinations for selecting and locating suitable routes for such pipelines, microwave systems, structures and other necessary facilities, subject to responsibility for any damage done to such property in making surveys and examinations.

⁷⁵ NM STAT. ANN. § 42A-1-1 *et seq.* (2008).

⁷⁶ NM STAT. ANN. § 42A-1-22 (2008).

⁷⁷ *See* 1983-1986 Op. Att’y Gen. N.M. 146 (1984) (discussing whether it was appropriate for the carbon dioxide pipelines to have eminent domain authority and finding that the legislature makes that determination. The petitioner raised the concern because CO₂ pipelines, when added to the New Mexico eminent domain power statute, were not used as a fuel by the general public, but for the extraction of oil and other petroleum products).

has the statutory authority to regulate interstate CO₂ transportation rates, the history of the STB's predecessor disclaiming jurisdiction in the ICC *Cortez* case leaves the STB jurisdiction over interstate CO₂ transportation uncertain at best. To date, the STB has not made an affirmative statement regarding its jurisdiction. Moreover, the STB rate regulation, even if it does attach, is limited to interstate pipelines and is sufficiently constrained as to offer little protection to customers.

Like the federal government, states have not devoted much attention to rate regulation for intrastate pipelines. Most CO₂ pipelines operate on a contractual basis for a specific application (i.e., EOR). As a need arises, states would likely respond with additional legislation.

Application of nondiscriminatory access requirements would require a pipeline operator to provide transportation service to any qualified entity that requests such service. Nondiscriminatory access is a requirement for receiving a permit under the MLA to cross federal lands.⁷⁸

The situation is less clear where a pipeline does not cross federal lands. Nondiscriminatory access requirements would arise under the ICCTA if CO₂ pipelines are found to be regulated under the Act, if the pipeline is an interstate pipeline, and if the pipeline holds itself out to provide transportation services for compensation. This would trigger regulation as a common carrier (referred to as a "pipeline carrier" under Title 49).⁷⁹ But, if a pipeline does not cross federal lands, and does not provide transportation to others, then the pipeline is not a "pipeline carrier" and would not be subject to STB jurisdiction, even if the STB otherwise had jurisdiction over CO₂ pipelines. Thus (even if the STB regulated CO₂ pipelines), if the CO₂ pipeline transports only its own CO₂, nondiscriminatory access provisions would not apply under Title 49, but would apply nonetheless under the MLA.

Nondiscriminatory access could become an important issue as the CO₂ pipeline network expands. Under various scenarios, an infrastructure could develop with high capacity pipelines transporting CO₂ to the most favorable CO₂ injection sites. These pipelines would transport CO₂ from numerous electric generation and industrial facilities, each of which could have different owners and operators. Policies aimed at avoiding duplication of facilities and capturing economics of scale may impel Congress or the states to impose nondiscriminatory access requirements.

Safety: The current safety regime is well-defined, with PHMSA minimum standards and delegation to states. State programs for CO₂ pipelines are managed by the same agencies that manage other pipeline regulation. This program of delegated authorities on pipeline safety seems to function well

“Further build-out of the CO₂ pipeline infrastructure would not appear to require any changes to the existing regulatory framework for pipeline safety...”

⁷⁸ 30 U.S.C. § 185(r) (2006).

⁷⁹ 49 U.S.C. §15501 *et seq.* (2006).

in practice.⁸⁰ Further build-out of the CO₂ pipeline infrastructure would not appear to require any changes to the existing regulatory framework for pipeline safety, so long as the safety regime stays up-to-date with current pipeline building practices.

Siting Authority: There is currently no federal siting authority for CO₂ pipelines, except over federal lands. Thus, under existing law, pipelines are largely dependent on state eminent domain authority to site both interstate and intrastate CO₂ pipelines, though it is not clear whether that authority is available in all of the states. As the pipeline network is expanded (particularly in or through states with no EOR experience), federal siting authority for interstate CO₂ pipelines may become a practical necessity.

3.5 Alternative Regulatory Frameworks

There are various approaches to regulate CO₂ pipelines. In recent Congressional testimony, the Chairman of FERC, Joseph Kelliher, discussed alternative models for regulation of CO₂ pipelines.⁸¹ He stated that there are three designs that the U.S. has used for transportation of energy resources that could be appropriate for regulation of CO₂ pipelines.

First, the existing model, as it currently stands for CO₂ pipeline regulation, could work. Under the current regime, states retain authority for siting CO₂ pipelines. The federal government involves itself only in siting CO₂ pipelines that cross federal lands. For economic regulation, assuming that the STB has jurisdiction, the STB only acts in the event that a rate complaint is filed. The Department of Transportation's OPS acts to ensure safety, with state involvement if states so choose. Chairman Kelliher expressed the view that this regulatory framework appears to be adequate.⁸²

Second, the model that currently exists for oil pipelines could be used for CO₂ pipelines. Under this model, the states would be responsible for pipeline siting. FERC, rather than the STB, would have authority for transportation rates and access. Safety issues would be handled by OPS.

Third, the natural gas pipeline model could be applied. This model envisions a larger federal role. FERC would have authority for the siting of CO₂ pipelines, like the authority provided for natural gas pipelines in the Natural Gas Act.⁸³ In addition, FERC would be responsible for transportation rates. The authority for pipeline safety would remain within the Department of Transportation, under PHMSA.

⁸⁰ There were only 4 "serious incidents" for onshore hazardous liquids pipelines in 2007, which are defined as those that cause a fatality or require hospitalization. See <http://primis.phmsa.dot.gov/comm/reports/safety/SerPSI.html>.

⁸¹ Testimony of the Honorable Joseph T. Kelliher, Chairman, FERC, before the Committee on Energy and Natural Resources, U.S. Senate (Jan. 31, 2008).

⁸² See *id.* Chairman Kelliher expressed his view that the STB has the authority to regulate CO₂ pipelines. At this point, the STB has not asserted that authority.

⁸³ 15 U.S.C. § 717 *et seq.* (2006).

With regards to siting, FERC Chairman Kelliher stated that “I would not recommend that Congress preempt the states on siting carbon dioxide pipelines, by providing for exclusive and preemptive federal siting of carbon dioxide pipelines.”⁸⁴

In addition, there are other models that could be used for siting of CO₂ pipelines. For example, if the need were demonstrated, a federal “backstop” authority, like that provided for electricity transmission siting in EPAct 2005, could serve to keep CO₂ pipeline development on schedule.⁸⁵ Under this model, states would have initial siting authority within certain designated corridors. However, if states fail to act and there is a need for such development, the FERC is authorized to issue a permit to developers of CO₂ pipelines. This authority would allow development in areas where it has been determined that there is a need. FERC would act to issue permits that would provide federal eminent domain authority to holders of those permits.

In another model, an “opt-in” approach could be used for CO₂ pipeline siting. The current regime of state siting would continue, but pipeline developers could choose whether or not to avail themselves of federal siting authority. Under this approach, CO₂ pipeline developers who need federal siting authority in connection with construction of their interstate CO₂ pipelines could apply for a federal certificate, which, if granted, would provide the developer with federal authority to construct and operate the pipeline using federal eminent domain authority, notwithstanding state law. If the Congress were to provide pipeline developers with federal eminent domain authority, it is likely that it would also subject the pipeline to some form of federal economic regulation by FERC or another agency. That regulation could entail nondiscriminatory access requirements modeled on the MLA or full rate and service regulations modeled on the NGA.

3.6 Likely Need for a Federal Role

The large build out of CO₂ pipeline infrastructure that will be required for large-scale commercial deployment of CCS will likely require substantial change in CO₂ pipeline regulation. In particular, it is not clear whether reliance on state-by-state siting processes and eminent domain authority will be sufficient to support construction—over a period of one or two decades—of a network of interstate CO₂ pipelines that may be equivalent in size to the current natural gas pipeline system. As a result, some developers will likely need access to a preemptive “one-stop” federal siting process and federal eminent domain authority to enable construction of this national CO₂ pipeline system.

In addition, existing law governing access and rate regulation of CO₂ pipelines is unclear at best. Greater certainty as to the extent of that regulation will help

“... large build out of CO₂ pipeline infrastructure ... will likely require substantial change in CO₂ pipeline regulation... some developers will likely need access to a preemptive ‘one-stop’ federal siting process and federal eminent domain authority.”

⁸⁴ Testimony of the Honorable Joseph T. Kelliher, Chairman, FERC, before the Committee on Energy and Natural Resources, U.S. Senate (Jan. 31, 2008).

⁸⁵ 16 U.S.C. § 824p (2006).

facilitate project financing. Moreover, if Congress is asked to grant federal siting and eminent domain authority to such pipelines, it is likely to impose some form of “common carrier” requirements, such as nondiscriminatory access and rate regulation.

Finally, the existing framework for safety regulation of CO₂ pipelines—which relies on a federal regulatory program, with delegation of some functions to state regulators—seems clear and workable.

In light of these considerations, our current inclination is to recommend that Congress give prompt and serious consideration to an “opt-in” federal regulatory regime for new CO₂ pipelines that would consist of the following elements:

- 1) The current system of state siting and economic regulation of CO₂ pipelines would be retained, except with respect to those new CO₂ pipeline projects for which a permit application is filed under (2) below.⁸⁶
- 2) Any entity proposing to construct a new CO₂ pipeline to transport CO₂ for purposes of permanent sequestration could elect to apply to FERC for a federal siting permit for the new pipeline. FERC would have exclusive authority, similar to that under the Natural Gas Act, to consider and grant or deny the applications. FERC could impose conditions on any permit granted.
- 3) Once a FERC permit is granted, the project sponsor would have federal eminent domain authority, and the permit would have the same preemptive effect over state and local land use regulation as a certificate of public convenience and necessity now does under the Natural Gas Act. *See supra* sec. II(a)(1).
- 4) When operational, the pipeline would be subject to non-discriminatory access and rate regulation similar to FERC’s current authority over oil pipelines and the STB’s authority over commodity pipelines. Prescriptive regulation of rates and service—on the Natural Gas Act model—would not be required.

Our current view is that Congress would be well advised to address these matters sooner rather than later, so that project sponsors will have greater certainty as to the CCS pipeline regulatory ground rules by the time that the first commercial scale CCS projects are ready for deployment. We welcome alternative viewpoints or suggestions for amending or elaborating this model, as the work of the CCSReg project proceeds over the coming months. Details on how to contact us are provided inside the front cover of this report.

⁸⁶ We do not recommend modifying the regulatory scheme for existing CO₂ pipelines. Our focus is on the regulatory changes that would be necessary to build out a new, larger CO₂ pipeline network to support CCS activities. There appears to be little need to modify the regulation of existing pipelines for this purpose.

Chapter 4: Overview of CO₂ Sequestration in Deep Geologic Formations

The purpose of this chapter is to describe the steps involved in developing, operating, and closing a geologic sequestration project, and to identify the legal and regulatory issues that must be addressed for sequestration to be a viable means of reducing CO₂ emissions to the atmosphere. The lifecycle of a geologic sequestration project is illustrated in Figure 4.1. We will refer to this diagram from time-to-time in later chapters as we address issues that arise in its various stages.

To ensure that deep geological sequestration of CO₂ is done in a manner that is safe, environmentally sound, affordable, compatible with evolving international carbon control regimes (including emissions trading), and socially equitable, it will need an institutional and regulatory framework that meets the objectives listed in Box 4.1.

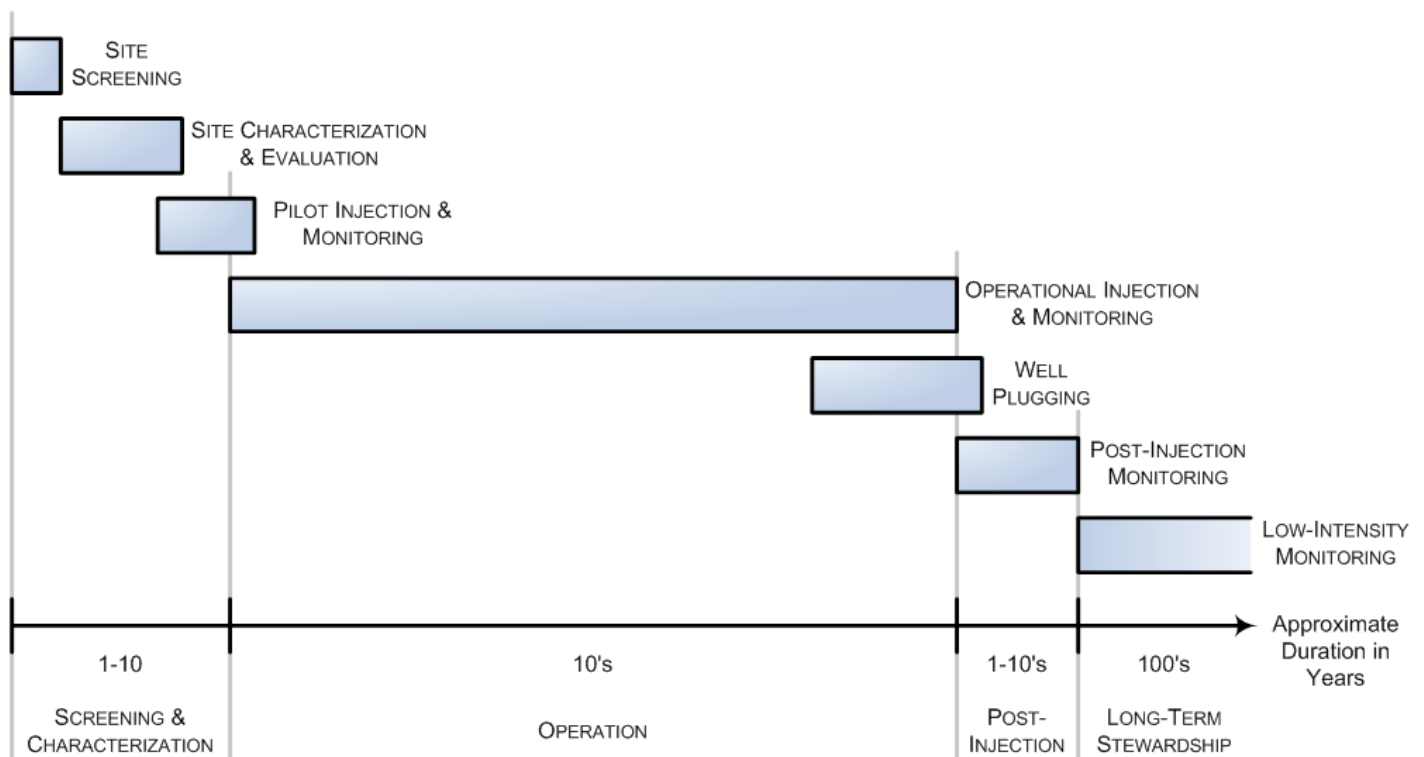


Figure 4.1: Lifecycle of a geologic sequestration project. Note that closure occurs at the end of the post-injection phase.

Box 4.1: Objectives for regulation of CCS

1. Ensure CO₂ sequestration is effective—that is, the vast majority of injected CO₂ is permanently trapped in the subsurface, and any leakage to the surface does not negate the benefits of sequestration.
2. Protect the health of those adjacent to sequestration projects.
3. Prevent degradation of underground sources of drinking water (USDWs).
4. Prevent degradation of ecosystems adjacent to sequestration projects.
5. Prevent degradation of adjacent mineral resources and protect access to those resources.
6. Ensure that pore space is utilized efficiently.
7. Ensure that pore space can be acquired through a process that is fair to pore space owners and project developers, as well as being reasonably predictable.
8. Develop regulations and regulatory structure that is responsive to new knowledge generated from early sequestration projects.
9. Encourage developers and operators to minimize the long-term cost of the project to the public after closure.
10. Minimize regulatory risk to the project developers while still adequately fulfilling other regulatory objectives.
11. Ensure that greenhouse gas emissions avoided through carbon sequestration are accounted for accurately and are fungible in a carbon market.
12. Encourage efficient coordination between capture, transport and sequestration operations.

While our focus in this report is on sequestration in deep geologic formations under the continental U.S., we should note that two of the first large-scale sequestration projects inject CO₂ into formations underlying the North Sea (see Box 2.2). In developing their regulations, both the UK and Australia are placing heavy emphasis on injection under the seabed. Storage under the deep seabed (i.e., approximately 2 km of water) may also be attractive because the density of CO₂ approaches the density of sea water at such depths and some mineralization reactions may be accelerated.¹

4.1 Exploration, Screening and Characterization

Through the Regional Carbon Sequestration Partnerships, the U.S. Department of Energy has performed a high level estimate of theoretical storage capacity for North America and estimated that there is geological capacity to sequester between 919 and 3,389 Gt of CO₂ on- or near-shore.² Substantial additional capacity may be available under the deep sea floors.³ Assessments at larger scales and higher resolutions (e.g., basin- and region-scale assessments)

¹ For further discussion, see House, K. Z.; Schrag, D. P.; Harvey, C. F., et al., Permanent carbon dioxide storage in deep-sea sediments, *Proceedings of the National Academy of Sciences* 2006, 103, (33), 12291-12295. and Goldberg, D. S.; Takahashi, T.; Slagle, A. L., Carbon dioxide sequestration in deep-sea basalt, *Proceedings of the National Academy of Sciences* 2008, 105, (29), 9920-9925.

² National Energy Technology Lab, Carbon Sequestration Atlas of the United States and Canada. US Department of Energy: Pittsburgh, PA, 2007; 86 p.

³ Goldberg, D. S.; Takahashi, T. and Slagle, A. L., "Carbon dioxide sequestration in deep-sea basalt", *PNAS*, v105, n29, pp 9920-9925, 2008.

are a necessary next step to refine estimates of available storage capacity and identify possible storage formations.^{4, 5}

During the site screening phase locations of CO₂ sources, information on regional geology (e.g., regional cross-sections, outcrop analysis), and publically available site-specific data from oil and gas exploration (e.g., seismic data, well logs, core analysis) must be analyzed to identify candidate sites. This analysis should focus on the suitability of the regional geology for sequestration (i.e., a resource assessment) and a screening level economic analysis (i.e., reserves assessment).^{6, 7}

The next step after a screening assessment is the more detailed characterization of site-specific geology in the most promising sites. Site characterization will include geophysical methods such as seismic and wireline logging, as well as geologic interpretation and evaluation supplemented by analysis of core samples from exploration wells (see Box 4.2). Potential sequestration sites must be shown to have sufficient capacity and injectivity to accept the desired volumes of CO₂ injected at commercial rates, and geology that will effectively contain CO₂ in the long-term. The information needed to make this case will likely include:⁸

- Structure contour maps of reservoirs, seals and aquifers;
- Detailed maps of the structural boundaries of traps where the CO₂ will accumulate, especially highlighting potential spill points;
- Maps of the predicted pathway along which the CO₂ will migrate from the point of injection;
- Reservoir fluid properties;
- Reservoir and seal petrophysical properties (e.g., porosity, permeability, mineralogy);
- Reservoir pressure and temperature conditions;
- Oil and gas production data (if a hydrocarbon field);
- Locations of nearby wells);
- Documentation and maps of faults and fractures, including their stability under injection pressures;
- Geologic maps showing any lateral changes in the reservoirs or seals; and,
- Magnitude and direction of water flow, hydraulic interconnectivity of formations and pressure decrease associated with hydrocarbon production.

“Potential sequestration sites must...[be] sufficient ... to accept the desired volumes of CO₂ injected at commercial rates ... and geology that will ... contain CO₂ in the long-term.”

⁴ Friedmann, S. J.; Dooley, J. J.; Held, H., et al., The low cost of geological assessment for underground CO₂ storage: Policy and economic implications. *Energy Conversion and Management* 2006, 47, 1894-1901.

⁵ Bachu, S.; Bonijoly, D.; Bradshaw, J., et al., CO₂ storage capacity estimation: Methodology and gaps. *International Journal of Greenhouse Gas Control* 2007, 1, (4), 430-443.

⁶ Bradshaw, J.; Bachu, S.; Bonijoly, D., et al. *CO₂ storage capacity estimation: issues and development of standards*, In 8th International Conference on Greenhouse Gas Control Technologies, Trondheim, Norway, 19-22 June 2006, 2006; Elsevier Science.

⁷ Bachu, S.; Bonijoly, D.; Bradshaw, J., et al., CO₂ storage capacity estimation: Methodology and gaps. *International Journal of Greenhouse Gas Control* 2007, 1, (4), 430-443.

⁸ Benson, S.; Cook, P.; Anderson, J., et al., Underground geological storage. In *IPCC Special Report on Carbon Dioxide Capture and Storage*, Metz, B.; Davidson, O.; de Coninck, H.; Loos, M.; Meyer, L., Eds. Cambridge University Press: Cambridge, U.K., 2005.

Box 4.2: Site characterization methods

A variety of tools have been developed for oil and gas exploration and production, and groundwater remediation that are applicable to exploration for CO₂ storage sites. These methods include:⁹

- **Seismic-** Seismic waves are generated from an energy source at the surface (such as small explosive charges and vibroseis trucks on land, or air guns in water) and an array of detectors record energy that returns to the surface due to reflection (or refraction) with subsurface geological features. The travel time of the seismic waves that arrive at the detectors can then be used to estimate the depth to geologic features of interest. In two-dimensional (2-D) seismic, data is gathered sequentially along linear seismic lines, while in three-dimensional (3-D) seismic data is typically gathered by placing detectors along “in-lines” orthogonal to a line of “shot-points,” also referred to as “cross-lines.” 3-D seismic is considerably more expensive than 2-D seismic, but has the benefit of generating higher resolution data that can be used to image a volume of the subsurface rather than only a vertical plane, as in 2-D seismic. Seismic receivers or energy sources can also be placed in a borehole in Vertical Seismic Profiling (VSP), which when coupled with traditional surface seismic, may allow ambiguities in the data to be resolved.
- **Geophysical Well Logging-** A tool or “sonde” is lowered to the bottom of a borehole and records information about the surrounding rock and fluids as it is drawn up the well. A large number of geological properties can be recorded using logging tools, including formation thickness and lithology, porosity, permeability, fluid saturation, and formation dip. Typically, a number of tools are combined to allow a number of properties to be estimated on one run. In addition, some well logging tools can be incorporated into the drillstring to log-while-drilling (LWD).
- **Core Sample Analysis-** During drilling a specialized bit can be used to retrieve a largely intact core of rock from the borehole. A large number of properties can then be measured in the lab, including: relative permeability curves, seal capillary entry pressure, and rock strength.
- **Pressure Testing-** The well bottom pressure is decreased by producing fluids from the well. Once steady state is reached, the production is stopped and the well is shut-in. Measurement of the gradual return of pressure to equilibrium allows the hydraulic properties of the reservoir to be estimated.

⁹ For more details, see Kearey, P.; Brooks, M.; Hill, I., *An Introduction to Geophysical Exploration*, 3rd ed.; Blackwell Publishing: Oxford, UK, 2002.; Hallenborg, J. K., *Standard Methods of Geophysical Formation Evaluation*. CRC Press: Boca Raton, 1998; 442 p., and Craft, B.; Hawkins, M., *Applied Petroleum Reservoir Engineering*, 1st ed.; Prentice-Hall: Englewood Cliffs, NJ, 1959; 437 p.

Data generated from the application of the tools discussed in Box 4.2 will allow a detailed model of the target reservoir to be developed. The results from this modeling can be used to project the behavior of the injected CO₂ over the long-term, to design the placement and configuration of injection wells,¹⁰ and to devise monitoring plans. Pilot injection of CO₂, conducted as part of the permitting process, will greatly further understanding of the reservoir properties and the site-specific behavior of the injected CO₂, allowing the geological model to be refined.¹¹ Screening analysis, site characterization and evaluation, and pilot injection and monitoring are collectively referred to as “site screening and characterization” in this report.

The site screening and characterization process is perhaps the most important step in the development of a sequestration project. The oft-cited IPCC conclusions that the fraction of injected CO₂ retained by sequestration projects “is very likely” to be “more than 99% over the first 1000 years” and that risks to human health and the local environment are no greater than those associated with similar oil and gas industry operations, are both contingent on sites being “well-characterized,” and “well selected, designed, operated and appropriately monitored.” The corollary to this is that no measure of good design, operation, and monitoring will prevent unintended migration and potentially leakage of injected CO₂—with the attendant risks to human health and the environment—from a site that is poorly suited for CO₂ sequestration. Best practices guidelines for site screening and characterization are summarized in the World Resources Institute (WRI) CCS Guidelines.¹²

However, to gather much of the data needed in the site screening and characterization phase—let alone to inject CO₂—will require that the developer gain permission from surface owners to access the land. Moreover, access to the subsurface for injection wells (and to inject CO₂) will require the developer to secure the rights to the pore space, and perhaps, depending on the type of project and state, mineral rights. At present, there is significant ambiguity about ownership of deep pore space and the right to inject CO₂. These issues are discussed in Chapter 5.

4.2 Site Operation and Post-Injection

Once site screening and characterization has been completed, operators and regulators must decide whether to proceed with large-scale injection operations. The regulatory issues that arise in permitting site operations are discussed in Chapter 6. Large-scale injection, associated monitoring and

“Pilot injection of CO₂, conducted as part of the permitting process, will greatly further understanding of the reservoir properties and the site-specific behavior of the injected CO₂...”

¹⁰ Most large projects will involve a large number of injection wells spread across the project footprint. Wells can be directionally drilled and may be horizontal. Use of directional drilling techniques can reduce the number of wells required and increase the fraction of the formation contacted by CO₂ than if only traditional vertical wells are used.

¹¹ Doughty, C.; Freifeld, B. M.; Trautz, R. C., Site characterization for CO₂ geologic storage and vice versa: the Frio brine pilot, Texas, USA as a case study. *Environmental Geology* 2008, 54, (8), 1635-1656.

¹² World Resources Institute, *Guidelines for CO₂ Capture, Transport and Storage*. Washington, DC, November 2008.

remediation (if necessary), and plugging of permanently suspended wells constitutes “operation” in this report.

During the operational phase, pilot facilities can be expanded to accommodate large-scale injection or, if the pilot facilities are inadequate, new facilities can be constructed and connected to the pipeline system linking the site to CO₂ sources. It may be necessary to drill new wells to maintain injection rates. It will certainly be necessary to rework any old wells that are not adequately plugged so as to ensure mechanical integrity and resolve operational issues. In addition, some wells will be suspended (i.e., temporarily plugged) or permanently plugged as pressures increase in some parts of the field.

Operations will be designed to use the geological sequestration capacity effectively, and to minimize potential risks. The risks posed by geologic sequestration are driven by the buoyancy of the injected CO₂ and the increased pressure in the receiving formation. Buoyant CO₂ is trapped in the subsurface through both physical and chemical mechanisms. The physical mechanisms retain CO₂ in the formation as a separate phase, contained by geologic structures, sedimentary features, or trapped by capillary action in the fine pores of rock as a residual phase behind a migrating CO₂ plume.¹³ Physical mechanisms are the dominant form of containment in the early years of operation.

Risks during the operational phase, shown in Figure 4.2, fall roughly into two categories—local risk to health, safety, or the environment and, global risk of CO₂ reentering the atmosphere and undermining climate change goals.¹⁴ Risks to drinking water could arise if CO₂ migrates out of the target formation into a drinking water aquifer or if brines displaced by injected CO₂ are forced into drinking water aquifers. If CO₂ leaks back to the near surface or surface, it could harm plant roots or soil ecosystems, or potentially accumulate in basements.

¹³ Benson, S.; Cook, P.; Anderson, J., et al., Underground geological storage. In *IPCC Special Report on Carbon Dioxide Capture and Storage*, Metz, B.; Davidson, O.; de Coninck, H.; Loos, M.; Meyer, L., Eds. Cambridge University Press: Cambridge, U.K., 2005.

¹⁴ Wilson, E. J.; Johnson, T. J.; Keith, D. W., Regulating the Ultimate Sink: Managing the Risks of Geologic CO₂ Storage. *Environmental Science and Technology* 2003, 37, 3476-3483.

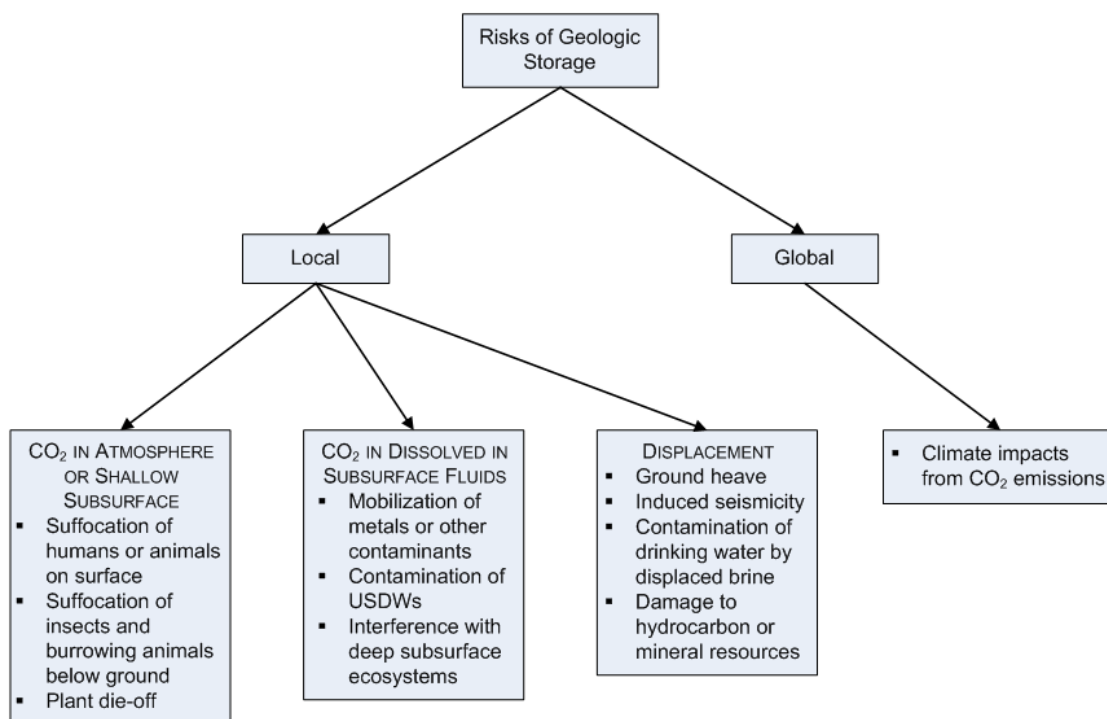


Figure 4.2: Risks associated with geologic sequestration of CO₂ classified by scale of impact.¹⁵

Over time, chemical trapping mechanisms supplement physical trapping—increasing storage security, as shown conceptually in Figure 4.3. Chemical trapping begins with dissolution of CO₂ into brine present in the formation, making the CO₂-saturated brine less buoyant than either the CO₂ phase or unsaturated brine. Dissolved carbon dioxide will react with minerals present in the formation to become immobilized—processes typically occurring on a scale of decades to centuries.^{16, 17} In addition, the pressure in the receiving formation, which reaches a peak at the end of injection, will steadily decline to a long-term equilibrium. Thus, the risk associated with the sequestered CO₂ increases through the operational period, and declines post-injection, as shown conceptually in Figure 4.4.

“Over time, chemical trapping mechanisms supplement physical trapping—increasing storage security ...”

¹⁵ Ibid.

¹⁶ Benson, S.; Cook, P.; Anderson, J., et al., Underground geological storage. In IPCC Special Report on Carbon Dioxide Capture and Storage, Metz, B.; Davidson, O.; de Coninck, H.; Loos, M.; Meyer, L., Eds. Cambridge University Press: Cambridge, U.K., 2005.

¹⁷ Bachu, S.; Bonijoly, D.; Bradshaw, J., et al., CO₂ storage capacity estimation: Methodology and gaps. International Journal of Greenhouse Gas Control 2007, 1, (4), 430-443.

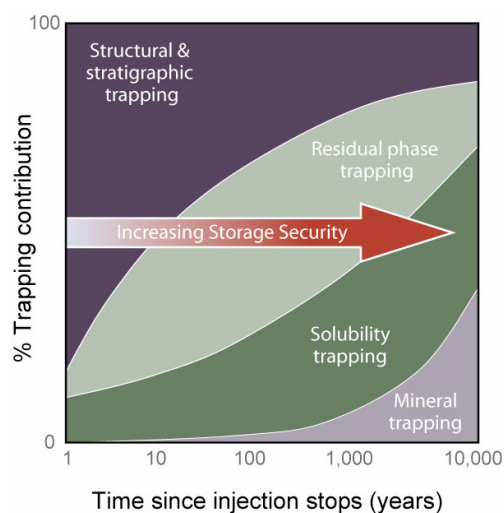


Figure 4.3: Relative contribution of trapping mechanisms to sequestration security over time. (source; Benson et al.¹⁸)

Monitoring will be key to managing risks of geological sequestration. Monitoring of injection parameters, the movement of the CO₂ plume, and composition of nearby underground sources of drinking water will undoubtedly be required. Results from monitoring activities will serve to protect human health and the environment and ensure that CO₂ remains sequestered from the atmosphere. Monitoring will also allow geologic models to be refined, increasing confidence in the predicted behavior of the site in the long-term. Box 4.3 identifies a number of the technologies available for monitoring injected CO₂ and other changes in the subsurface.

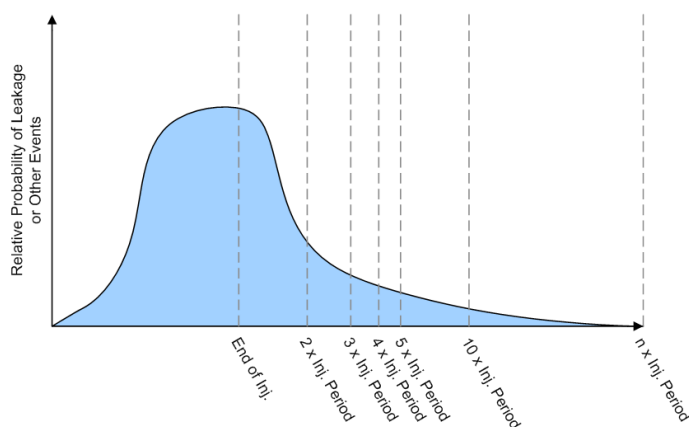


Figure 4.4: Conceptual risk profile for an idealized sequestration site over time. (figure adapted from Dr. Sally M. Benson, Stanford University.)

¹⁸ Benson, S.; Cook, P.; Anderson, J., et al., Underground geological storage. In *IPCC Special Report on Carbon Dioxide Capture and Storage*, Metz, B.; Davidson, O.; de Coninck, H.; Loos, M.; Meyer, L., Eds. Cambridge University Press: Cambridge, U.K., 2005.

Box 4.3: Technologies available to monitor the injected CO₂ and other changes in the subsurface

A large number of tools have been developed for oil and gas exploration and production, natural gas storage, waste injection, and groundwater monitoring that can be applied to CO₂ sequestration¹⁹. However, the applicability of a monitoring tool to a CO₂ sequestration project depends both on the specifics of the site (i.e., subsurface geology) as well as the motivation for monitoring. The matrix below, modified from Benson et al.,²⁰ shows potential motivations for monitoring, available tools, and their applicability.

Motivations for monitoring at pilot scale and early-mover projects will be different than those at larger commercial projects. For example, early projects should include more intensive monitoring to increase knowledge about storage processes occurring in the subsurface and the specific location of the injected CO₂. Later, large commercial projects may focus on monitoring to verify that injected CO₂ has not migrated out of the reservoir. Tools that may be applicable to meet these monitoring objectives range from very simple and inexpensive, such as measurement of wellhead pressures and flow rates, to much more intensive and expensive, such as time-lapse 3-D seismic.

	Wellhead & Formation Pressure	Injection & Production Rates	Casing & Annulus Pressure Testing	Temperature	Well Logging	Fluid Composition	Active Seismic Methods	Microseismic	Electrical & Electromagnetic Surveying	Gravity Surveying	Land Surface Deformation	Tilt Measurements	Airborne or Satellite Imaging	Soil Gas and Vadose Zone Monitoring	Atmospheric CO ₂ Concentration & Surface Flux Monitoring
Establish a pre-injection baseline															
Ensure effective injection control															
Detect the location of the CO ₂ plume															
Assess integrity of wells, both operating and abandoned															
Identify storage efficiency & trapping mechanisms															
Developing a model history match															
Detect & quantify surface leakage															
Assess environmental, health, & safety impacts of leakage															
Design and evaluate remediation efforts															
Certification for financial transactions (e.g., credits)															
Evaluate impacts on other subsurface resources															
Settle legal disputes stemming from CO ₂ injection															
Indicates the method is feasible to use															
Indicates the method may be possible to use															

¹⁹ Wilson, E. J.; Gerard, D., *Carbon Capture and Sequestration: Integrating Technology, Monitoring and Regulation*. Blackwell Publishing: Oxford, UK, 2007; p 269.

²⁰ Benson, S. M.; Gasperikova, E.; Hoversten, M. Overview of Monitoring Techniques and Protocols for Geologic Storage Projects; IEA Greenhouse Gas R&D Programme: Stoke Orchard, UK, 2004.

“In general, using geophysical methods, it is unlikely that the mass of CO₂ in-place can be estimated with greater than 20% precision ...”

Sequestration project sites will be selected, and projects designed and operated to ensure that CO₂ is retained in the subsurface. The amount retained can be estimated directly by measuring the mass of CO₂ in the subsurface, or indirectly subtracting the rate of leakage from the rate of injection.

Attempts to directly estimate the amount of CO₂ in-place at the Sleipner project (offshore Norway) using geophysical measurements coupled with modeling have been able to account for 50% to 80% of the CO₂ injected—depending on the assumptions about subsurface conditions and distribution of the CO₂.²¹ While no leakage is suspected from the Sleipner project, these attempts have been inadequate to make a precise estimate of retention. In general, using geophysical methods, it is unlikely that the mass of CO₂ in-place can be estimated with greater than 20% precision, which is not sufficient to guarantee the effectiveness of sequestration.²²

Estimating retention indirectly (i.e., the amount injected minus leakage) is also hampered by a lack of precision in measurement methods. The flow rate of CO₂ injected into the formation can be gauged to a precision of approximately 2%.²³ Likewise, measuring fluxes of CO₂ between the surface of the ground and the atmosphere over hundreds of square kilometers—the typical area of a CO₂ storage project—will not be possible at reasonable cost or with needed precision.

While not allowing for quantification, a number of the methods presented in Box 4.3 may be able to detect leakage. If leakage is occurring from a small portion of the project footprint, such as from a fault or well, some monitoring techniques could quantify leakage, allowing emissions from the project to be appropriately accounted under climate change legislation (see Chapter 10 for discussion).²⁴

After the site reaches capacity, injection operations will cease, indicating the beginning of the “post-injection” phase. Monitoring will continue, using geophysical techniques and some monitoring wells, to document the gradual drop in subsurface pressure as the system returns to equilibrium and, potentially, monitor for migration of CO₂ out of the target formation.²⁵ During this time wells not needed for monitoring will be plugged. Geoscientists believe that, should problems associated with a completed project arise, they are most

21 Nooner, S. L.; Eiken, O.; Hermanrud, C., et al., Constraints on the in situ density of CO₂ within the Utsira formation from time-lapse seafloor gravity measurements. *International Journal of Greenhouse Gas Control* 2007, 1, (2), 198-214.

22 Benson, S. M., Monitoring Carbon Dioxide Sequestration in Deep Geological Formations for Inventory Verification and Carbon Credits. In *SPE Annual Technical Conference and Exhibition*, Society of Petroleum Engineers: San Antonio, TX, 2006.

23 Ibid.In.

24 Ibid.In.

25 Carroll, S.; Hao, Y.; Aines, R., Geochemical Detection of Carbon Dioxide in Dilute Aquifers. In *Seventh Annual Conference on Carbon Capture and Sequestration*, Exchange Monitor Publications: Pittsburgh, PA, 2008.

likely to occur during the first few decades after closure. The purpose of the post-injection phase is to screen for such problems. Once the site is behaving as expected (i.e., based on modeling and monitoring) and the CO₂ no longer poses a significant risk of leakage to the surface or to drinking water resources, the site can be closed. At this point, open wells would likely be plugged and both the frequency and intensity of monitoring activities would decrease (i.e., monitoring only if the need arises).

The WRI CCS project has developed best practice guidelines for site operations, monitoring, and management of the post-injection phase.²⁶ However, the structure of the regulatory program and legal aspects surrounding tort liability during operation are outstanding questions. Chapters 6 and 8 address options to structure the regulatory framework for sequestration and management of tort liability, respectively.

4.3 Long-term Stewardship

Once injection of CO₂ has stopped at a sequestration site and the site has been appropriately closed (following a post-injection monitoring period), some entity must be responsible for oversight of the facility on a permanent basis. This oversight is referred to as “long-term stewardship,” and discussed in detail in Chapter 7.

Projects should not move into the long-term stewardship phase until they have demonstrated that the injected CO₂ is stable and presents no significant risks. Storage security will be increasing during the long-term stewardship phase, but nevertheless, some entity should be delegated to handle any problems that should arise.

When several injection projects operate in one sedimentary basin (i.e., a depression in the Earth’s crust in which sediments have accumulated, such as the Permian or Michigan Basins), long-term stewardship for a closed site may have to account for possible interactions and influences with adjoining active injection sites. This is also an issue that has to be addressed in site permitting and operations, the regulatory and legal aspects of which are dealt with in Chapter 6.

“Should problems associated with a completed project arise, they are most likely to occur during the first few decades after closure.”

“Long-term stewardship for a closed site may have to account for possible interactions and influences with adjoining active injection sites.”

²⁶ World Resources Institute, *Guidelines for CO₂ Capture, Transport and Storage*. Washington, DC, November 2008.

Box 4.4: Comparisons between geologic sequestration and nuclear waste

Frequently, people who are not familiar with CCS technology make comparisons between CO₂ sequestration and nuclear waste storage. However, the only real similarity is that both nuclear waste storage and geologic sequestration of CO₂ must provide secure containment on long time scales—time-scales that are much longer for nuclear waste. Other than that, comparing nuclear waste disposal and carbon sequestration is misleading. Nuclear waste disposal must safely manage small volumes of a highly toxic substance; geologic sequestration must safely deal with very large volumes of a non-toxic substance. Carbon dioxide becomes significantly more stable in the subsurface on the time scale of decades to centuries (see Figure 4.4); nuclear waste remains hazardous for millennia. Commercial-scale deployment of CCS will entail hundreds of geologic sequestration sites; the nuclear industry aims to site a single national repository (and has operated for decades without siting a single nuclear waste disposal site). The final distinguishing feature is that nuclear waste disposal is intrinsically a federal enterprise and will be federally supported, whereas CCS is likely to retain a strong component of local control and operate through market mechanisms.

While the physical comparison to nuclear waste is not appropriate, it is useful to consider the Price-Anderson model for addressing liability that has been developed for nuclear power plants. That is discussed in Chapter 8.

4.4 The Need for a Two-Stage Approach

An effective regulatory framework will need to coordinate activities and manage risks across the life cycle of a geological sequestration project. While there is obvious pressure to institute a definitive regulatory approach for CCS as quickly as possible, and a number of issues can be resolved now, we believe that it would be a mistake to finalize specific details of the regulatory framework before gaining experience with large-scale injection undertaken over time, in a number of geological settings. Today, with the exception of two projects offshore of Norway, and a project in Algeria, all CO₂ injection projects have been much smaller than those that will be required for commercial-scale operation of CCS. This suggests a two-stage approach, in which we gain experience with a dozen or more large-scale projects in the U.S. and elsewhere around the world. In the U.S., these can be undertaken under existing regulatory arrangements and then later grandfathered under any new regulatory regime. In Chapter 11, we return to this issue, and discuss how such a two-stage approach might be adopted in practice.

Box 4.5: What about safety?

Geologists who have studied CCS at length are confident that a well designed and properly operated project will retain CO₂ deep underground with virtually no leakage to the surface. As noted in Section 4.1, the IPCC has said that the fraction of injected CO₂ retained by sequestration projects “is very likely” to be “more than 99% over the first 1000 years.” The longer the CO₂ is in place, the more likely that geophysical and geochemical processes will have immobilized it. Thus, unlike some other kinds of waste for which the risk stays constant or grows over time, the risks presented by CCS can be expected to decline with time.

However, people inevitably ask, what if the experts are wrong?

There are several sources of evidence that suggest that slow leakage to the surface would pose little or no risk to public health. For example, across much of Italy, natural CO₂ of volcanic origin seeps steadily to the surface (Figure 4.5). While in a few locations people have CO₂ monitors in closed spaces, such as basements, risks to public health and safety have been extremely low and easily managed. There have of course been a few places around the world where large natural CO₂ seeps have resulted in serious problems.²⁷ Thus, for example, regulators may find it prudent to monitor the levels of CO₂ if deep stable lakes lie over injection sites. Large persistent natural seepage has also caused ecological damage in some locations.²⁸ Before such levels were reached from a CCS injection field, a variety of other indicators should make it possible to detect the problem and take corrective action.

What about the risks posed by a short-duration, large volume leak of CO₂ to the surface? Clearly, a large leak would pose some risk to the climate (the alternative pursued today, however, is 100% leakage up the stacks of power plants and other industrial facilities). Public health risk would again likely be minimal. Figure 4.6 shows a measurement program undertaken by Lawrence Livermore National Laboratory of a geyser



Figure 4.6: Measurements made by Lawrence Livermore National Labs at at Crystal Geyser, UT suggest that the risks posed by short-duration, large volume leaks are relatively low. Photos from Julio Friedman.

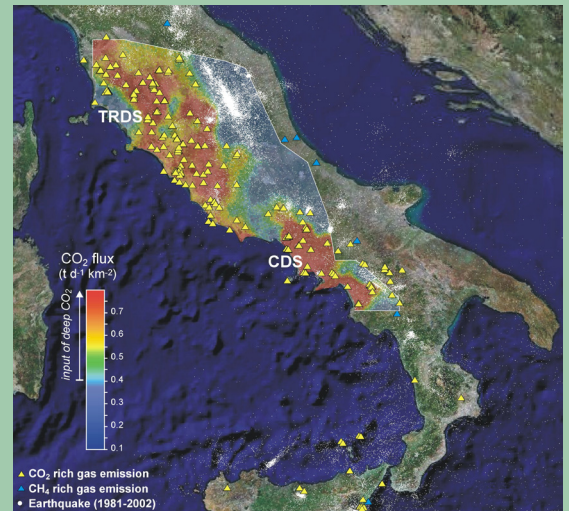


Figure 4.5: Levels of natural CO₂ seepage of volcanic origin across Italy. Yellow triangles show locations of CO₂ rich gas emissions. Figure courtesy of Giovanni Chiodini. Base map from Google.

driven by CO₂ erupting from an 800 meter deep well drilled at Crystal Geyser, UT in 1936. Near the well, the concentration of CO₂ was far below levels causing harm and, 100 meters from the well, modeling suggested the concentration of CO₂ was only 100 ppm higher than the background CO₂ concentration.²⁹ Note the people standing safely around the erupting geyser.

²⁷ Benson, S. M.; Hepple, R.; Apps, J., et al. *Lessons Learned from Natural and Industrial Analogues for Storage*; Lawrence Berkley National Laboratory: Berkley, CA, 2002.

²⁸ Ibid.

²⁹ Bogen, K.; Burton, E. A.; Friedmann, S. J., et al. *Source terms for CO₂ risk modeling and GIS/simulation based tools for risk characterization*, In 8th International Conference on Greenhouse Gas Control Technologies, Trondheim, Norway, 19-22 June 2006, 2006; Elsevier Science.

Chapter 5: Access To and Use of Pore Space for CCS in the Deep Subsurface

Along with questions about long-term stewardship (Chapter 8), the legal issue that looms largest for the viability of CCS in the U.S. is who—if anyone—owns the pore space that will be used for the geologic sequestration (GS) of CO₂. While the U.S. has been blessed with many geological formations that are suitable for the permanent sequestration of CO₂, before a project can be developed, a candidate geological formation must be carefully characterized. Project developers will need to acquire the right to carry out geological and geophysical testing, and then, if the geologic formation is found to be suitable, the right to use the pore space for GS as discussed in Chapters 4 and 6.

In most other parts of the world, including Canada, Europe and Australia, the majority of the subsurface is the property of the government. Thus, most transactions that involve using resources, including oil, gas and minerals, as well as injection into the pore space, require a transaction of some kind with the national government. As a consequence, acquiring rights to characterize pore space and engage in deep sequestration is likely to be more straightforward in these nations than it currently would be under private land in much of the U.S.

In the U.S., while public ownership of land is important, especially in the West, private ownership of land and water rights is the norm in much of the country. The federal government owns nearly 30 percent of this nation's mineral rights—about 25 percent of domestic production of both oil and gas come from federally owned property¹—and the states own tens of millions of acres of minerals.² In the U.S. today, as historically, it is transactions involving privately owned minerals that dominate. However, as we note in Section 5.2, there are also examples that suggest that there is no clear ownership governing the right to inject waste fluids into deep pore space.

It is axiomatic in Anglo-American law that the owner of property rights can transfer those rights in whole or in part. Where an owner transfers less than the whole bundle of property rights they own, the rights have been “severed.” It is common in the U.S. for mineral rights to be severed from the surface rights in land. Sometimes, mineral rights are severed by a reservation in a deed transferring the surface. On other occasions, severance is by a direct grant of the mineral interest. A severance may also divide ownership of several kinds of minerals. To further complicate matters, in the case of natural gas storage, there are legally recognized property interests in the pore space used for storage, which may be severed from both the mineral and surface rights.

¹ Private parties lease the right to develop and produce minerals on private lands.

² Lowe, J.S., *Oil and Gas Law in a Nutshell*, 4th Edition, Thomson West (2003).

“...to date, in most of the U.S., no clear property right to use pore space has been assigned to surface property owners covering the injection of waste fluids into deep geological formations ...”

Property rights are also traditionally managed by states, and rules governing access, ownership, and transfer vary considerably by state jurisdiction.

While the number of legal cases that have addressed the issue is modest, to date, in most of the U.S., no clear property right to use pore space has been assigned to surface property owners covering the injection of waste fluids into deep geological formations, and most injection under the EPA underground injection control (UIC) program goes on without approval from surface land owners except for those on whose property the injection well is located. However, recently, there have been a few states who have begun to move to assign pore space rights for GS of CO₂ to surface property owners.³

5.1 Choice of the Physical Delineation of Pore Space

There are fundamentally two ways in which pore space could be physically delineated:

- 1) in terms of surface property boundaries;
- 2) in terms of the properties of the geological structures into which injection will occur.

The latter is analogous to the way in which mineral rights to a vein of hard-rock minerals are now defined. Typically, someone who owns the rights to the minerals in that vein can mine them wherever they run under surface properties. Defining pore space solely in terms of geological structures could work well for formations that are spatially compact. Difficulties would arise for formations that extend over a very large region into which several widely spaced projects might wish to inject. In this case, some division of the formation would be likely, although there is no compelling reason why that sub-division would need to conform to surface property lines. Additionally, many large formations underlie several different states, making governance claims particularly vexing.

If the decision were to identify pore space in terms of the physical structure of the geological formation, then the region identified for use for GS might sometimes be further sub-divided in terms of portions of that formation that have specific physical characteristics. For example, if there is a formation with a clear trapping structure, the pore space allocated for use by GS might be delineated as shown in Figure 5.1.

³ Wyoming HB 89.

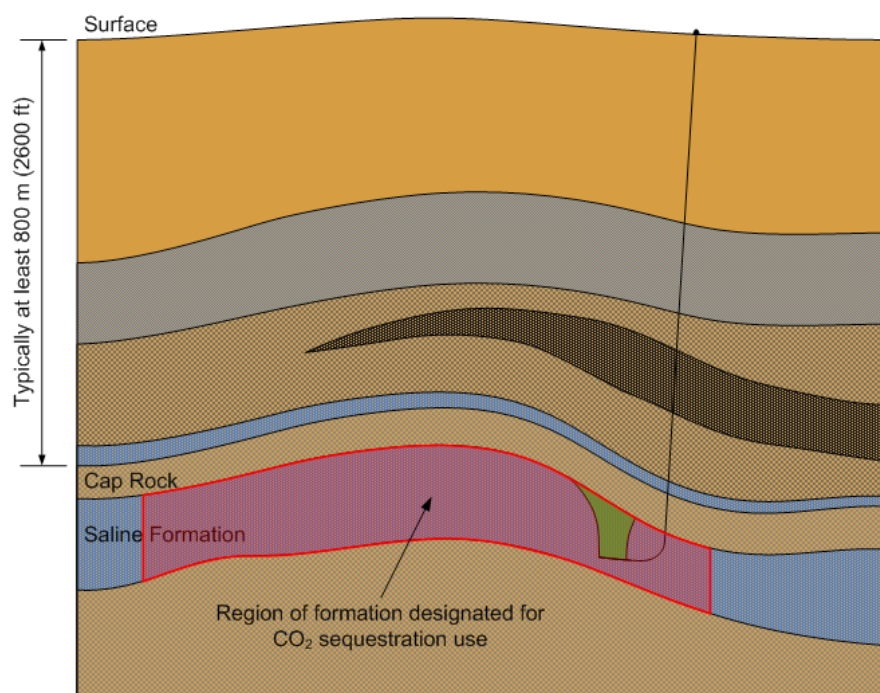


Figure 5.1: Example of identification of a region of a pore space formation for use in capture.

5.2 Structuring the Issues of Ownership

John Sprankling notes that the concept that landowners own everything from the surface of the earth up to the heavens and down to the center of the earth is more a convenient metaphor than a legal reality.⁴ With the development of aircraft, the courts placed limits on ownership to the heavens.⁵ Sprankling argues that evolving technical capabilities should lead to similar limits in deep subsurface ownership.

In reality, today there is no uniformity, either from state-to-state or from fluid-type to fluid-type, in the way in which rights to inject fluid into deep pore space are currently being handled. For example, in many locations, surface property owners collect rents from firms using pore space to store natural gas under their properties.⁶ In contrast, in a case involving the deep injection of hazardous waste operating under the UIC, the Ohio Supreme Court basically truncated the depth of subsurface rights, limiting responsibility for trespass to those fluid migrations that might interfere with the “reasonable and foreseeable” use by surface owners.⁷

“... the concept that landowners own everything from the surface of the earth up to the heavens and down to the center of the earth is more a convenient metaphor than a legal reality.”

⁴ Sprankling, J.G., *Owning the Center of the Earth*, 55 UCLA L. Rev. 979 (2008).

⁵ U.S. v. Causby, 328 U.S. 256 (1946).

⁶ Box 5.1 explains that some of these rents can become quite substantial. Others are small, as low as 3-5\$ an acre, and in some cases, sold in perpetuity.

⁷ For a more detailed discussion see Elizabeth J. Wilson and Mark A. de Figueiredo, “Geologic Carbon Dioxide Sequestration: An Analysis of Subsurface Property Law,” *Environmental Law Reporter*, 36, 10114 2006. Wilson and Figueiredo note another case in which the U.S. Court of Appeals of the Fifth Circuit, did find responsibility for trespass (had it occurred) they conclude had trespass been proved, “it is unlikely that any damages would have been awarded as no harm to existing or future interests could be proven. Whether compensation could have been demanded is unclear.”

“...most projects injecting fluids under the UIC program have not secured permission from surface property owners.”

It appears that most projects injecting fluids under the UIC program have *not* secured permission from surface property owners. In many cases, the volume of injections under UIC are small, but injections of waste fluids by the oil and gas industry can be comparable to CCS projects. Similarly, wastewater treatment facilities in southern Florida inject over 3 billion tonnes per year of treated wastewater into underground formations⁸ with no approval or authorization from surface property owners.

At least two states have begun to act to assign property rights for deep pore space for use in GS. Recent legislation in Wyoming assigns that right to surface property owners. Montana has started to do the same, but the legislation is still under review by the state’s Energy and Telecommunications Interim Committee.⁹ If property rights to pore space are held in private hands, issues may arise involving “hold outs,” who could prevent the development of a project. This issue is discussed further in Section 5.6.

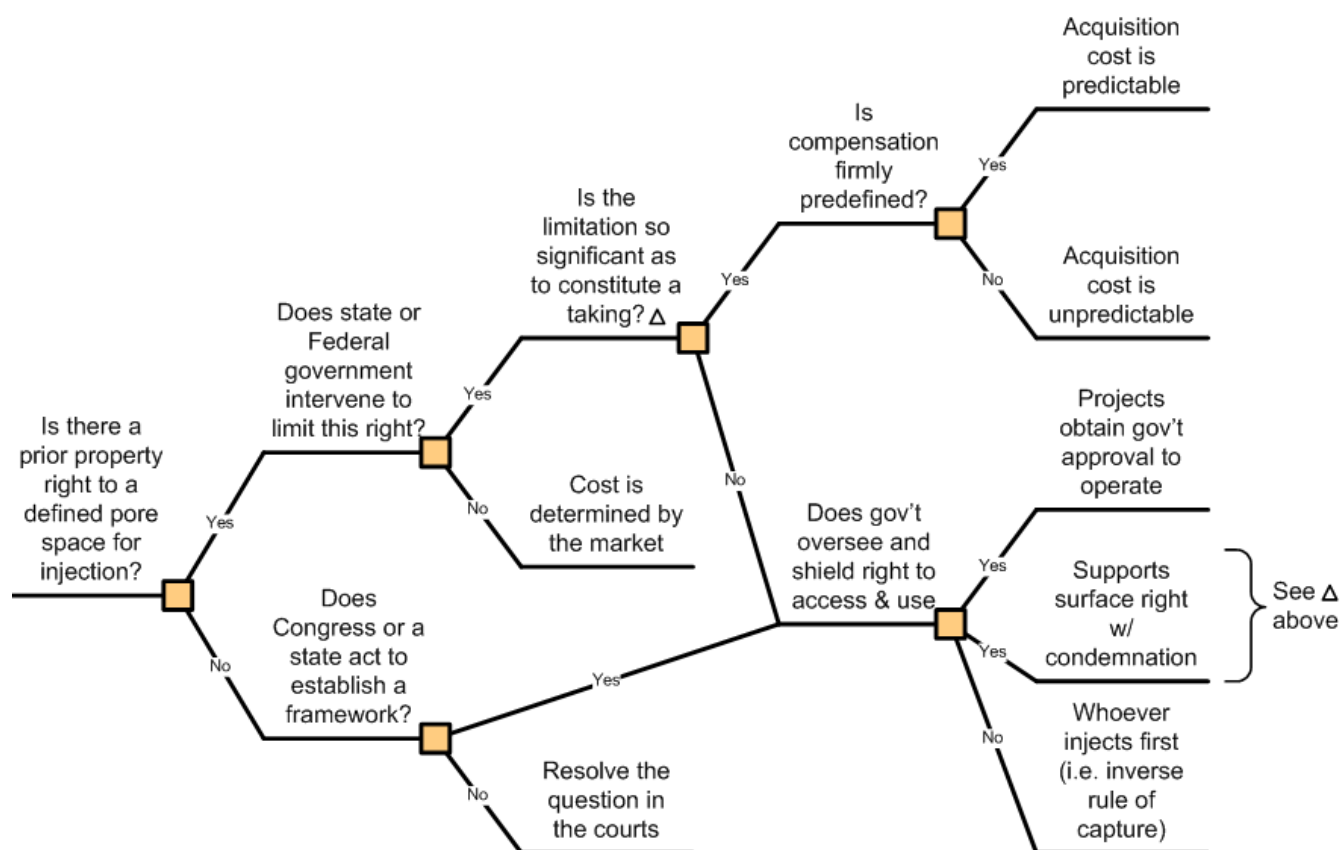


Figure 5.2: Choice options for alternative legal frameworks to govern access to and the use of deep pore space for GS.

⁸ Keith, D. W.; Giardina, J. A.; Morgan, M. G., et al., Regulating the Underground Injection of CO₂. Environmental Science and Technology 2005, 39, 499A-505A.

⁹ In an October 24, 2007 memo, Todd Everts, a member of Montana’s Energy and Telecommunications Interim Committee Legal Staff, commented, “if states use natural gas storage law as a model in clarifying property interests associated with CO₂ injection and storage, then there are legally recognized property interests in the subsurface pore spaces and that the general preponderance of the case law concludes that the surface estate owner also owns the subsurface storage pore space.” Available at http://leg.mt.gov/css/committees/Interim/2007_2008/energy_telecom/assigned_studies/co2page/co2.asp.

The decision tree in Figure 5.2 begins with the question of whether anyone enjoys a prior property right to inject CO₂ into pore space. The answer to that question triggers a series of additional policy and legal questions. How they are resolved will determine whether and how carbon sequestration will be able to move forward.

Consider first the lower branch of this diagram that applies to portions of the country in which it is determined—or assumed without challenge—that no vested property right currently exists in the deep pore space for CO₂ sequestration. In this case, both Congress and the states have the option of fixing legal ownership of this space in some manner. In the absence of such action, sooner or later the issue will be resolved in the courts on a case-by-case basis. The result could easily be a patchwork of different legal situations in different parts of the country.

One alternative would be for legislatures to adopt a so-called “inverse rule of capture,” determining in effect that the subsurface rights vest in whoever is able to assert them physically on a first-come basis. This appears to be what has happened in many injection projects now operating under the UIC program. We elaborate how such a regime might work in Section 5.3.

Legislative action to fix the existence and nature of rights would have the benefit of establishing clear and uniform principles that would yield predictable outcomes, particularly if Congress passed federal legislation, applicable throughout the country. Additionally, such efforts at standardization could help to foster coordination when geologic basins underlie several different state jurisdictions. Under the Supremacy Clause of the U.S. Constitution, such congressional action would likely preempt any state laws that conflict with the federal enactment. Legislators could endorse the assumption that surface landowners own the corresponding deep subsurface. If done, this would require compensation (perhaps at a *de minimis* level) to the surface landowner for any sequestration, either by agreement or through the exercise of eminent domain. This option is discussed in Section 5.4.

Alternatively, legislators could declare that the subsurface rights are vested in the state or federal government. A government permitting process could then be created to allow individual sequestration projects to move forward. For example, under such a system allocation of the right to assess and use pore space for GS in all strata underlying the surface lands and waters of the U.S. below some specified vertical depth (e.g., 1 km¹⁰) might be declared the responsibility of the federal government. In Section 5.5, we elaborate how

“...legislators could declare that the subsurface rights are vested in the state or federal government.”

10 A depth of 1 km is slightly deeper than minimum depth at which CO₂ typically exists as a supercritical fluid. This far exceeds a depth below which conventional residential or commercial landowners might plausibly make use of the subsurface.

such a regime might work. Such a regime might also be created on a state-by-state basis under state laws, which either create a similar arrangement based on the properties of geological formations, or assign rights to surface property owners.

Turning next to the upper branch of the diagram in Figure 5.2, if the law is found to already assign ownership of the deep subsurface for use in GS, then federal and state lawmakers confront the question of whether to intervene to affect that right in some manner. Government routinely limits the rights of property holders,¹¹ and could do the same in this case. It could, for example, support condemnation of deep pore space to allow GS projects to go forward. Or, on the grounds that the degree of taking associated with using pore space at depths of a kilometer or more imposes a negligible burden on the use rights of surface property owners, government could set compensation at low or even negligible levels. These options are discussed at greater length in Section 5.4.

Should lawmakers intervene, the question becomes whether the intervention meets the constitutional standard for a taking of private property within the meaning of the Fifth Amendment to the U.S. Constitution. This is a complex legal question which, if resolved in the negative, would have the simplifying effect of leaving government with the same discretionary choices outlined above (and the same federal supremacy principles) for establishing a framework for use of the deep subsurface. On the other hand, should the U.S. Supreme Court decide (or let stand a lower court ruling to the same effect) that use or regulation of the deep subsurface constitutes a Fifth Amendment taking, then the government must decide (and courts must ultimately pass on the legality of) whether and how to fix the constitutionally required just compensation for such a taking.

A decision not to intervene would not, in itself, preclude sequestration projects; rather, it would consign the developers of such projects to private negotiations with the appropriate owners. If the state or federal government does not intervene to limit that right, then acquisition of deep pore space for GS will require separate transactions with each property owner. In the West, where much of the land is federal, and where private holdings are large, this might be feasible. In the East, especially in places like the Ohio River Valley that are densely populated with coal-fired power plants, acquiring such rights would entail transactions with hundreds or even thousands of separate property owners. Even in the absence of “hold outs,” it is possible that this could be so expensive as to preclude development of CCS. Box 5.1 explores an illustrative scenario in which costs to acquire pore space could run as high as \$450-million under such a regime. This situation is further discussed in Section 5.6.

¹¹ Government limits the rights of property owners through mechanism such as zoning laws, water permits, and powers of eminent domain.

5.3 Operation Under an Inverse Rule of Capture

In most of the United States, some variant of the “rule of capture” determines ownership of natural resource flows such as oil and gas.¹² The top level of this basic ownership framework also dictates ownership of groundwater.¹³ Simply put, the rule means that the first person to capture the resource and convert it to personal property owns that resource. In the context of oil and gas production, so long as the holder of the mineral rights to oil and gas conducts recovery operations without trespassing or interfering with the rights of neighboring owners, who also have the right to drill into the same formation, the mineral rights holder will not be liable for drainage. This rule has been described as a rule of convenience, meaning that the rule is developed from the courts’ recognition of society’s need for energy resources, rather than from the logic of earlier precedents. It is also known as a rule of non-liability since there exists no actionable claim for drainage by adjacent landowners. Several states modify this rule by giving the surface owner a right to sue to prevent injury or waste of oil and gas reserves, but similarly provide that the surface owner does not hold direct title to those resources.

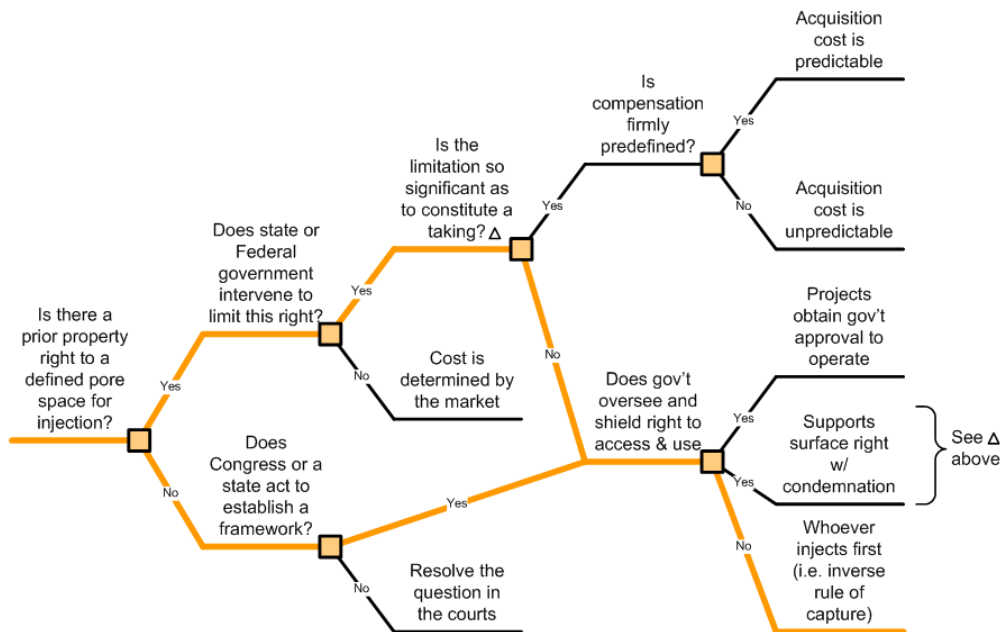


Figure 5.3: Illustration of routes through the decision tree that could lead to the establishment of an inverse rule of capture.

¹² While neither of the two prominent state-level doctrines concerning ownership and production of oil and natural gas—namely, the “ownership in place” and “non-ownership” doctrines—are expressly termed a “rule of capture,” these axioms nevertheless closely adhere to the highest order mechanics of the capture rule: that is, in order to own the resource, it must be captured and thus reduced to personal property. For a more detailed explanation of the nuances of these two doctrines, see generally Richard W. Hemingway, *The Law of Oil and Gas*, 29-36 (4th ed. 2004).

¹³ We recognize that numerous state-level groundwater ownership doctrines exist in the United States today, specifically the “absolute ownership,” “reasonable use,” “prior appropriation,” “correlative rights,” and statutory permit systems, but a detailed discussion of the nuances of each of these rules is outside the scope of this report. In their simplest forms, each groundwater ownership doctrine ultimately requires that the resource be captured in order to convert it to personal property. For a thorough explanation of groundwater rights, see generally Jan G. Laitos, *Natural Resources Law*, 1134-1141 (2006).

Limitations on the rule of capture have been recognized in situations where the productive capacity of a reservoir is enhanced by injecting fluids to increase the pressure differential between the injection and production wells, thereby driving the oil or gas in place to the production well. Generally, when fluids such as water or CO₂ are injected into a reservoir to improve oil recovery and these substances travel into adjacent subsurface holdings without authorization causing damage, the injector will be liable.¹⁴ However, when injection has been part of a water flood program that has been approved by a state oil and gas regulatory authority, which results in the flooding of surrounding wells, it has been held that the public benefit realized by encouraging development of oil and gas resources supercedes the right of an adjacent landowner to enjoin the program.¹⁵ In this sense, the intrusion can be classified as non-actionable subsurface trespass due to overriding public policy. This finding of non-liability is referred to as the “inverse rule of capture.” However, not all secondary recovery operations are protected by the inverse rule of capture. In *Tidewater Oil Co. v. Jackson*,¹⁶ the court awarded the damaged adjacent landowners compensatory damages using an analysis similar to a condemnation action where property values are lost by private action authorized by a state agency to prevent waste.

The potential exists for a successful argument to extend the non-liability protections provided under the inverse rule of capture to CO₂ storage. Precedents for this appear to exist in the case of a number of on-going injection programs being conducted under the EPA/State UIC program. While in most cases the volumes involved in these cases are modest, in the case of Florida, injection is in excess of 3 billion tonnes per year, with apparently no agreements from any surface or other property owners.¹⁷

It could plausibly be argued that the public benefit of reducing the concentration of CO₂ in the atmosphere outweighs any right to enjoin a CO₂ storage operation by a surface or mineral owner holding interests in property adjacent to a CO₂ injection well. Rather, the pore space rights could vest in the injection operator who physically occupies the strata with CO₂ before any neighboring individual or entity begins natural resource recovery operations. However, while the CO₂ sequestration operation could not be enjoined in this situation, the inverse rule of capture should not limit the right of the mineral owner or his or her lessee to the reasonable use of the subsurface for mineral exploration and production, so as to not alter any state law regarding the

¹⁴ *West Edmond Hunton Lime Unit v. Lilard*, 265 P.2d 730 (Okla. 1954).

¹⁵ *See Railroad Commission of Texas v. Manziel*, 361 S.W.2d 560 (Tex. 1962). *See also Baumgartner v. Gulf Oil Corp.*, 168 N.W.2d 510 (Neb. 1969), cert denied, 397 U.S. 913, 90 S.Ct. 914, 25 L.Ed.2d 93 (1970) (court states that orthodox rules of trespass are not appropriately applied to subsurface intrusions under authorized secondary recovery unit); *See also Mowrer v. Ashland Oil & Refining Co.*, 518 F.2d 659 (7th Cir. 1975) (allowing recovery on an amalgamation of nuisance and strict liability theories); *See also West Edmond Salt Water Disposal Ass'n v. Rosencrans*, 226 P.3d 965 (Okla. 1950).

¹⁶ 320 F.2d 157 (10th Cir. 1963), cert denied, 375 U.S. 942, 84 S.Ct. 347, 11 L.Ed.2d 273 (1963).

¹⁷ Keith, D. W.; Giardina, J. A.; Morgan, M. G., et al., Regulating the Underground Injection of CO₂. *Environmental Science and Technology* 2005, 39, 499A-505A.

primacy of the mineral estate. If, however, that extraction were done in a way that resulted in the release of CO₂ or damage to the mineral estate, the operator might incur a liability.

Referring to Figure 5.3, we see that either Congress or the states could develop a framework establishing operation under a negative rule of capture, though neither government entity, or its agencies, would oversee and manage the right to access and use subsurface pore space for GS. Depending on how an inverse rule of capture was formulated, the GS operator could inject CO₂ into the formation which might migrate through the strata, even if this results in the displacement of more valuable with less valuable substance. Of course, migration of any injected fluid is only permissible provided the migration is in compliance with regulations covering injection operations (Chapter 6), does not interfere with preexisting mineral recovery operations, cause damage to any adjacent subsurface and overlying surface properties, or endanger public health and safety.

5.4 Operation With Compensation to Surface Property Owners

The two routes through the decision tree shown in Figure 5.4 lead to outcomes under which operators might have to compensate surface property owners, but where that level of compensation would be predictable, perhaps even at a *de minimis* level.

“... Congress or the states could develop a framework establishing operation under a negative rule of capture.”

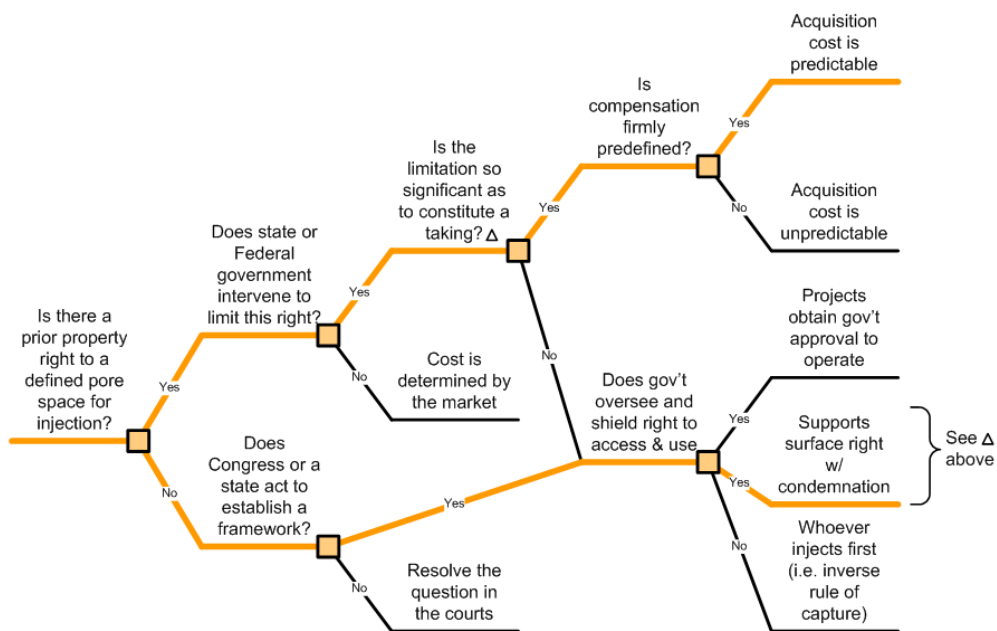


Figure 5.4: Routes through the decision tree that lead to results with predictable costs for the acquisition of pore space.

“...fees could be specified to be de minimus on the grounds that, in most cases, there is no obvious other plausible planned or foreseeable use for the pore space, and hence no significant taking ...”

Consider first the upper branch of the tree in which it is determined that someone has a prior property right to the use of the pore space for the purposes of sequestering CO₂. State legislatures or the Congress could specify that if projects meet all relevant regulatory requirements (of the sort discussed in Chapter 6), property owners must allow CO₂ sequestration to proceed. They could further specify the amount of compensation, or a rule by which to compute the level of compensation, that property owners may demand for use of the pore space for sequestration.

For example, they might specify:

- A flat fee per acre payable to the property holder;
- A per tonne fee for CO₂ injected payable to the property owners;
- A one time fee based on a fraction of the value of the injected CO₂ at the time of injection.

In each of these cases, the fees could be specified to be *de minimus*¹⁸ on the grounds that, in most cases, there is no obvious other plausible planned or foreseeable use for the pore space, and hence no significant taking, unless the property holder could demonstrate otherwise.¹⁹ Of course, those costs could be significant in the case that injection makes it difficult or impossible to extract valuable mineral resources that it is plausible the owner might produce in the foreseeable future.

Since any of these limits would constitute a taking, their ultimate deposition would likely depend on a judgment by the state and federal courts, and ultimately the Supreme Court. Thus, such strategies would need to be carefully crafted by Congress or state legislatures and would carry some uncertainty until such legal questions were definitively resolved.

We move now to the bottom leg of the diagram in Figure 5.4. On the basis of a finding of pressing public interest in securing appropriate places for the permanent sequestration of CO₂, Congress or state legislatures could either explicitly adopt a law that allows the government to use its powers of eminent domain and condemn lands, or achieve much the same result by declaring that no action shall be maintained in federal or state court for any subsurface trespass caused by the duly-licensed injection and sequestration of CO₂ below some specified vertical depth (e.g., 1 km). Of course, for this immunity to apply, any subsurface property acquired this way would have to

¹⁸ It should be noted that even *de minimus* fees could lead to aggregate payments that are on the order of tens of millions of dollars (see Box 4.2, note 27) depending on the size of the CO₂ plume.

¹⁹ Conceptually, the most relevant example may be the *Loretto v. Teleprompter* cases, where in *Loretto I* (458 U.S. 419), the Supreme Court held that an obligation to allow the installation of cable television equipment is a mandatory, or forced, taking of property from owners of multiple dwelling unit apartment buildings; and where in *Loretto II* (446 N.E.2d 428), the Court of Appeals of New York held that specification of the value of that taking by the New York Public Service Commission at a nominal rate (\$1 per customer) was an adequate expression of the value of, and compensation for, that taking; that is unless the property owner meets the burden of proof for demonstrating that the diminution in value of the property was materially different than the general assumption, and is thus entitled to receive greater compensation.

be used exclusively for the purpose of sequestering CO₂. If it is to be viable, such a right of appropriation would probably have to be without prejudice to the rights of the owner of the land or minerals, including the right to drill or bore through the appropriated underground stratum or formation, if done in accordance with regulations developed to protect the underground sequestration strata or formation against the escape of CO₂. If it is determined that an underground mineral deposit is depleted of oil, gas, or other minerals, or abandoned by the mineral owner, it could then be considered pore space under this proposal. However, given that conventional oil production²⁰ typically leaves 40% to 60% of the oil originally in place trapped in the reservoir,²¹ balancing the sequestration and mineral interests could prove challenging in formations with active oil and natural gas production.

In order to characterize and operate an injection project, access must be gained to surface property. While it would be possible to provide eminent domain options to obtain easements and right-of-way for access to underground reservoirs, it seems likely to us that in most cases, arrangements could be made to obtain such access via public lands or through normal commercial transactions with surface property owners.

5.5 Legislative Action Makes Government Responsible for the Allocation of Pore Space for Geological Sequestration

Because CCS could mitigate the potential catastrophic effects of climate change, it could be argued that the conversion of subsurface property for GS is a public interest. Given the existing patchwork of subsurface property rights and mineral and water laws in this country, it is both unrealistic and undesirable to try to achieve blanket state or federal ownership of the subsurface. However, it might be feasible to place *deep* pore space for use in GS under the sovereign control of state or federal government and to enact a statutory regime that standardizes procedures for access to and utilization of deep subsurface pore space for that purpose. If a comprehensive federal statute, or coordinated set of state statutes, were developed to achieve this end, it should focus on pore space below a depth at which CO₂ will remain a supercritical fluid (typically about 800 meters).

“state or federal government... access ... could be allocated on the basis of competitive bidding ...”

²⁰ Conventional oil production methods include primary recovery driven by gas expansion (i.e., gas drive), water influx (i.e., waterdrive), and pumping (i.e., artificial lift), as well as waterflooding.

²¹ Blunt, M. F.; Fayers, F. J.; Orr, F. M., Carbon Dioxide in Enhanced Oil Recovery. *Energy Conversion and Management* 1993, 34, (9-11), 1197-1204.

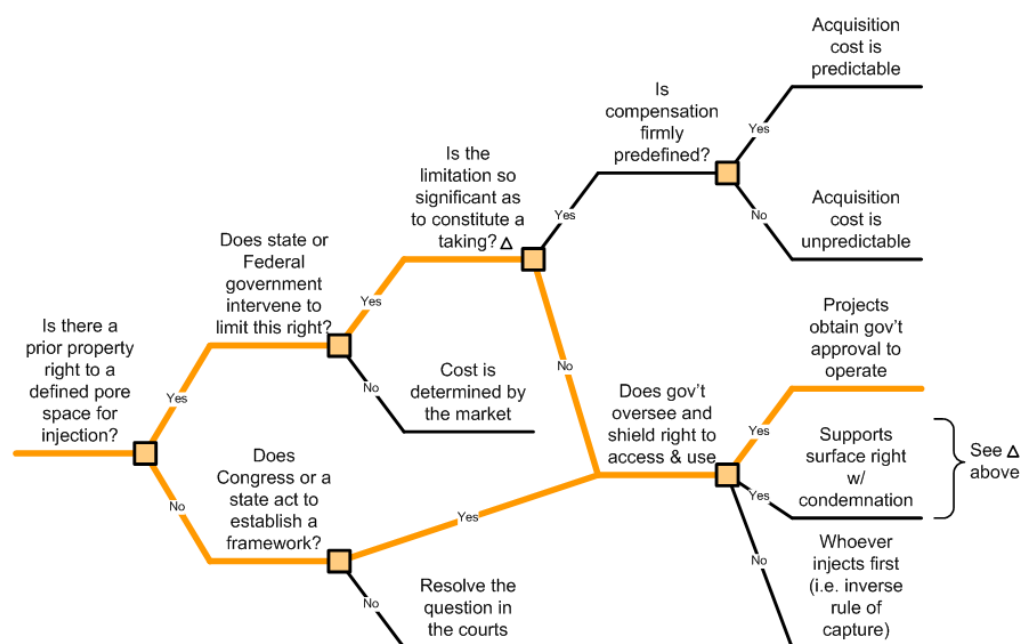


Figure 5.5: Routes through the decision tree that could make state of federal Government responsible for the allocation of pore space.

Under such a system, all pore space²² in all strata below some specified depth (e.g., 1 km) would be declared vested in the state or federal government. Access to characterize such pore space for purposes of GS could be allocated on the basis of competitive bidding, and rights to perform such characterization could come with an option to undertake GS (assuming that all other regulatory requirements are met) within a specified period of time. A requirement should be included in any state or federal law that data on subsurface pore space gathered under such a regime be placed in the public domain.

Such legislation could be written to recognize existing contracts to use the pore space and limit future contracts. It could also be written to not alter the primacy of the mineral estate in any state. Thus, any subsurface easements obtained under this type of arrangement would not limit the right of a mineral owner or his or her lessee to reasonable use²³ of the subsurface for mineral exploration and production. Once it is determined that an underground mineral deposit is depleted of oil, gas, or other minerals, or clearly abandoned by the mineral owner, it could be considered pore space under this arrangement. If CO₂ were injected into an authorized reservoir but traveled into adjacent zones not authorized by the state or Federal lease, and caused damage, the injector could be made liable for trespass.²⁴

²² The details of a legislative scheme to delineate between pore space utilized for CCS and all other injection activities, or between injection of fluids for permanent disposal (e.g., CCS and hazardous waste) and temporary storage (e.g., natural gas storage) is open to discussion.

²³ "Reasonable use" should be explicitly defined, with the primary purpose of the standard being to ensure no CO₂ sequestered in the subsurface escapes to the atmosphere. If it does, appropriate costs should probably be borne by entity cause the release while extracting the minerals.

²⁴ This is similar to trespass claims arising out of unauthorized enhanced recovery operations. See *West Edmond Hunton Lime Unit v. Lilard*, 265 P.2d 730 (Okla. 1954).

Federal Jurisdiction: While an arrangement of the sort outlined in this section could be created either on a (hopefully coordinated) state-by-state basis or as a single federal regime, there could be significant benefits to implementing it at the federal level (perhaps with delegation of some operations to the states). In addition to federal lands, which would be managed by the federal government, a federal regime could be created that would allow for coordination across jurisdictions. A federal regime would minimize difficulties when a GS reservoir crossed state (or national) boundaries. Coordination at the federal level might also minimize difficulties that could arise when trading credits for sequestered CO₂ in international markets.

If a federal system were established, the right to explore a specified region of pore space might be acquired through a competitive bidding process overseen by a federal agency, such as the Bureau of Land Management (BLM). In addition to the right to explore, a lease obtained to characterize the pore space under a specific tract of land would carry with it an associated option to develop and inject CO₂ for permanent sequestration. The exercise of this option would be contingent on obtaining the necessary permits from federal or state agencies, such as the EPA or state-level equivalent.

The term of leases should be limited (e.g., five-years) after which the lease term could be extended if the lessee exercised the development option and was making a good-faith effort to develop the site. Once development begins in earnest, it is essential that there is a real certainty on the part of the developer that the lease will not be rescinded. If the lessee decided to abandon characterization or operations, all rights to and interests in the pore space would revert back to the federal government. In the interests of building a comprehensive understanding of U.S. pore space, the enabling legislation should require that, all geologic data acquired during exploration be submitted to the U.S. Geological Survey (USGS), which would act as a public repository for these data.

5.6 Legal Arrangements That Could Make the Development of CCS Difficult

If the federal or state governments do not intervene to manage or limit private property rights for the use of pore space for GS, or create such rights but do not firmly define compensation for acquisition of these rights, the development of GS projects could be costly due to high rental rates that states or private property owners could demand. Box 5.1 demonstrates how this situation could play out in Pennsylvania if the current commercial leasing structure and annual lease rates for natural gas storage are adopted for GS. This result could be the same even if Congress, or the states, establish a framework for condemnation procedures yet stop short of predefining just compensation rates.

“If the federal or state governments do not intervene to manage or limit private property rights... development of GS projects could be costly due to high rental rates states or that private property owners could demand.”

Thus, faced with highly variable and unpredictable acquisition costs, would-be GS developers might be dissuaded from moving forward with a project before even attempting negotiations with the appropriate landowners and mineral rights holders.

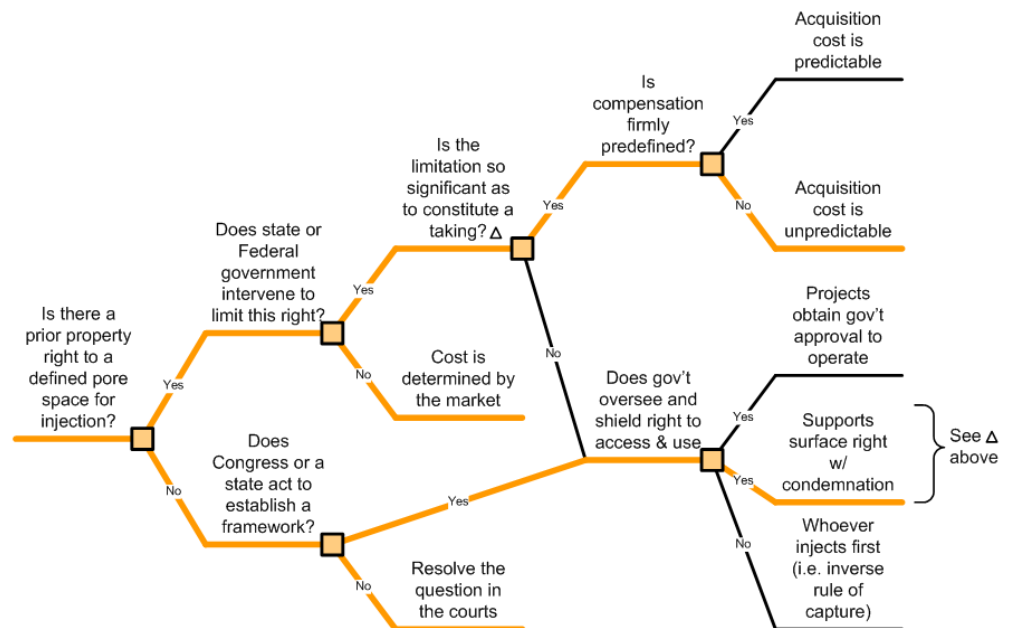


Figure 5.6: Routes through the decision tree that could make the development of CCS costly and difficult.

If neither Congress nor the states act to establish a framework for access to and use of deep pore space sequestration of CO₂, disputes over ownership and fair compensation will be left to the courts. Relying on the courts to adjudicate disagreements about subsurface property rights and contractual obligations between GS site-developers or operators and private property owners could significantly delay, if not permanently halt, the development of many CCS projects. This discussion of judicial barriers to GS development assumes, of course, that the appropriate property owners will have agreed to the use of the deep pore space in which they hold a vested property interest. As noted in the introduction to this chapter, “hold-out” landowners could prevent development of CCS, especially in the Eastern U.S. where there are innumerable small private land holdings.

The Interstate Oil and Gas Compact Commission (IOGCC) CO₂ Geological Sequestration Task Force has developed a state-level conceptual framework to address the scenario of hold-out landowners. The IOGCC argues that the Model Oil and Gas Conservation Act already deals with GS of CO₂ through

its regulatory provisions dealing with the underground storage of natural gas. They suggest that state legislation is necessary to clarify initial ownership and property interests in deep pore space, as well as the procedures for accessing pore space. The framework would allow GS site-developers and operators to exercise state-granted eminent domain authority over any subsurface stratum found to be suitable and in the public interest for sequestration of CO₂. While the creation of a standardized condemnation framework at either the state or Federal level is a potentially viable method by which to secure the subsurface property interests needed for large-scale deployment of CCS, the IOGCC's proposal imposes a significant number of qualifying conditions on the right to exercise eminent domain power. Most relevant from the perspective of this chapter is the IOGCC's proposed pore space valuation procedure, under which a potential sequestration operator would have to designate the amount of proven commercially producible accumulations of oil or natural gas remaining in the formation targeted for sequestration in order to determine the compensation owed to the mineral interest owner. This could lead to protracted negotiations and legal disputes as experts on either side of the negotiation argue that their respective reservoir models demonstrate the presence of more or less recoverable oil and gas compared to others'.

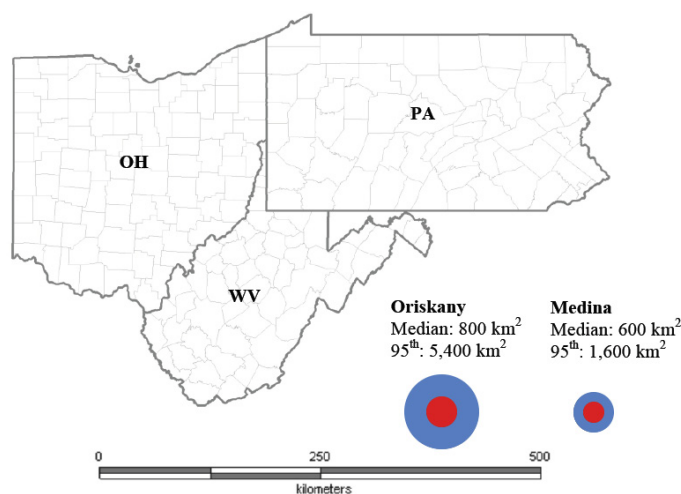
There are other legal mechanisms that provide a potential answer to the problems presented by hold-outs and the lack of a standardized compensation structure, but these approaches would also need to be created and backed by a legislative enactment. Forced unitization, adapted from oil-field development, is essentially a contractual instrument backed by Federal or state-granted powers of eminent domain, that requires hold-out landowners to allow the use of their deep pore space for CO₂ storage if the majority of the surface acres²⁵ (e.g., 50-60%) have committed to the GS project through private negotiations. Alternatively, commentators have suggested the creation of state or regionally-based cooperatives whose representatives would negotiate on behalf of private landowners. These cooperatives could achieve the dual benefit of alleviating the potential administrative nightmares faced by site developers of having to negotiate with hundreds or thousands of property owners, while ensuring that every property owner receives fair compensation for the use of their deep pore space. Again, this institution would need to be constructed through legislation to ensure that standard processes and compensation metrics are employed. However, a cooperative arrangement could nevertheless run into similar negotiation and adjudicatory barriers as the IOGCC's framework. As a result, many proposed GS projects could be significantly delayed, if not cancelled, due to such drawn-out disputes.

²⁵ Though not necessarily the majority of the surrounding landowners.

Box 5.1: How big could an injection field be? What might it cost under different regimes?

To explore the question of how much area the “footprint” of a CO₂ injection site might cover, and how much access might cost if some exiting precedents were adopted, we have modeled an injection of 50-million metric tonnes (MT) of CO₂ over 30-years (roughly 1.7 MT annually) into two geologic formations: the Medina Group and Oriskany sandstones in Pennsylvania. Both of these formations have been identified as potential sequestration targets. PhD student Lee Gresham used a stochastic simulation²⁶ that models the temporal-spatial evolution of a CO₂ plume using well data available for each of the two sandstone formations. The results from this analysis give a range for CO₂ plume size (50th to 95th percentile) from 600 km² to 1,600 km² (200-600 mi²) for the Medina Group sandstone, and 800 km² to 5,400 km² (300-2,100 mi²) for the Oriskany sandstone formation. This range is illustrated in the figure below. These results illustrate that CO₂ plumes could evolve to be very large in size, thus considerably complicating the legal complexity and economic cost if subsurface property rights must be acquired from surface land owners.

We estimated lease costs using three economic models designed to compensate property owners for the fair market value of their pore space based on the going rate for leases to store natural gas under public and private land. We estimate the total discounted²⁷ cost in 2008 dollars of leasing pore space for a period of 30-years for sequestration could range from \$700,000 to \$450-million across the three scenarios.²⁸ This is roughly the equivalent of \$0.02 to \$9 per tonne CO₂, which is comparable to the cost of CO₂ storage (not including pore-space cost), which is estimated to be between \$0.5 to \$8 per tonne CO₂.²⁹ Thus, if pore space must be acquired from surface property owner at rates such as those that have applied for natural gas storage in Pennsylvania, the prospective cost of acquiring pore space rights could double the total cost of storage, making it economically prohibitive to sequester CO₂ in otherwise suitable formations. It is therefore critical to examine alternative economic models for compensating subsurface property owners and limiting property rights to the deep subsurface. Without such developments, the cost of pore space acquisition for large-scale GS in the U.S. could be a “show-stopper” for CCS.



26 Model based on a solution presented by Nordbotten, J. N.; Celia, M. A.; Bachu, S., Injection and Storage of CO₂ in Deep Saline Aquifers: Analytical Solution for CO₂ Plume Evolution During Injection. *Transport in Porous Media* 2005, 58, 339-360.

27 Using a 10% discount rate & 4% inflation rate.

28 The lease rates examined range from \$2 per acre to \$100 per acre across the three economic models. Aggregate payments under the \$2 per acre scenario could exceed \$10-million if the CO₂ plume is greater than a couple thousand square miles.

29 Metz, B.; Davidson, O.; de Coninck, H., et al., *IPCC Special Report on Carbon Dioxide Capture and Storage*. Cambridge University Press: Cambridge, U.K., 2005; p 442.

5.7 Summary

There is considerable ambiguity as to whether in the U.S. today anyone holds the right to inject CO₂ into deep pore space for GS. Most of the injections of waste fluids conducted under the UIC program do not appear to have secured rights or permission from any surface or subsurface property owners. At least a few of those injection projects involve volumes of fluid as large or larger than the volumes of CO₂ that will be involved in commercial-scale CCS projects.

As Figure 5.2 and the discussion in this chapter indicate, whether and how this issue is resolved carries profound implications for the future viability of CCS in the U.S. Given the very large capital investments that will be required to implement CCS, it seems doubtful that very many projects will go forward without a clear resolution of the right to use pore space for GS.

An inverse rule of capture, which appears to be the way in which most waste injection is now operating, could be formalized by state or federal law. Such legislation would then likely be tested in the courts, and if implemented state-by-state, could result in different outcomes in different states.

A system that places all approvals for access to and use of pore space for GS at depths of greater than some specified depths (e.g., 1 km) under federal responsibility has clear advantages. Whether it would be politically feasible for the U.S. Congress to implement such an arrangement is unclear, and would certainly depend on the political climate and the attitudes of federal courts over the coming decade. Not only would such an arrangement obviate the problems that might arise when receiving reservoirs involve more than one state, it could also lead to more orderly and simplified project development and limit issues that might later arise as CCS enters into international trading or other carbon control regimes.

If a clear property right is assigned (for example to surface property owners) federal legislation could still limit that right, requiring access with either *de minimis* or modest compensation in most cases. This could also be done on a state-by-state basis. Project development might be less orderly and systematic under such an arrangement. However, implementation might present fewer political and legal hurdles.

Note that half of the routes through the decision tree (Figure 5.6) result in outcomes that could make it infeasible to implement large commercially viable CCS projects. Given the urgent nature of addressing the climate problem, this is clearly an outcome that we must work hard to avoid.

“Note that half of the routes through the decision tree... result in outcomes that could make it infeasible to implement large commercially viable CCS projects.”

In our next report, it is our intention to offer firm recommendations. However, for the moment we are still working to develop and refine the full range of alternatives and articulate their strengths and limitations. We ask readers to offer their critical advice and suggestions, both for improved treatments of the options we have outlined, or for entirely new options that we have not considered.

Chapter 6: The Regulatory Framework for Injection Operations

Regulations will provide the structure to ensure that injection operations are safe and successful. As explained in Chapter 4, once a region of pore space has been identified as potentially appropriate for use in sequestration, a project developer must gain approval from some appropriate regulatory authority to proceed with developing and operating the site. Permitting rules must verify that a proposed site has a high likelihood of being able to accept and contain commercial quantities of injected CO₂, and they must require operators to design operating, monitoring, and remediation plans appropriate for the specific site conditions.

In the U.S., large volumes of various waste materials are currently disposed of through underground injection under regulatory oversight provided by the EPA Underground Injection Control (UIC) Program. In Section 6.1, we describe that program and also discuss the recent proposal by EPA that an additional class of wells (Class VI) be added to address the needs of geologic sequestration (GS). Several states have also begun to develop approaches to regulating GS site operations and these too are discussed in Section 6.1. While the best approach may in fact be a simple extension of existing arrangements under the UIC Program, we do not think it wise to assume this without careful consideration. Thus, in Section 6.2, we identify and discuss a range of approaches that might be adopted in regulating GS injection operations. We conclude in Section 6.3 with a discussion of the pros and cons of a range of possible institutional and regulatory arrangements. In evaluating these alternatives, the question of how best to meet the objectives laid out in Box 4.1 is clearly a key consideration.

6.1 The Underground Injection Control Program

Any discussion of how to permit sequestration operations must begin with a consideration of three issues: the existing Underground Injection Control (UIC) Program; EPA's proposed regulations for carbon dioxide geological sequestration wells;¹ and, early state initiatives to regulate GS.

The Current UIC Program: The UIC program began in 1979, and first promulgated regulations in the 1980's. It operates out of the EPA Office of Water, under the authority of the Safe Drinking Water Act (SDWA) of 1974.² This act gives precedence to protecting and preserving drinking water aquifers

¹ FR 73 pp. 43491-43541 (July 25, 2008)

² 42 U.S.C. § 300f *et seq*

“The current UIC provides important experience relevant to regulating GS, including experience with the injection of CO₂... large volumes... buoyant fluids, and injection... requiring long-term containment”

over any other private or public interest. The protection applies independent of the depth of the water bearing structure and independent of whether the water is actually in use as a source of drinking water (or is a practical source of drinking water). All such waters are termed Underground Sources of Drinking Water, or USDWs.³

The UIC program defines five classes of wells, summarized in Figure 6.1.

- Class I wells inject hazardous waste, industrial non-hazardous waste, and municipal wastewater. There are approximately 550 Class I wells.⁴ Construction, monitoring, and reporting requirements are generally the most stringent for Class I hazardous wells. All Class I wells must inject below the deepest drinking water aquifer.
- Class II wells are associated with oil or gas production. They include disposal wells, enhanced recovery wells, and hydrocarbon storage wells. There are approximately 144,000 Class II wells in the U.S.⁵ Wells that are injecting carbon dioxide for enhanced oil recovery (EOR) fall in this class.
- Class III wells are used for solution mining of minerals below the deepest drinking water aquifer. There are approximately 18,500 Class III wells.
- Class IV wells inject hazardous or radioactive wastes above or into a drinking water aquifer. They are banned unless specially authorized as part of a groundwater remediation project. Nationwide, 32 sites use Class IV wells.⁶
- Class V includes all other kinds of injection wells. Class V wells typically inject non-hazardous waste into shallow formations. There are 400,000 to 650,000 Class V wells—the exact number is not known.⁷ In March 2007, the EPA issued guidance for pilot project geological sequestration wells to be permitted as Class V, experimental wells.⁸

Under the UIC program, the EPA (or states with UIC primacy) has authority to exempt some USDWs, thus allowing injection where it would otherwise be prohibited. The Agency explains that an exempted aquifer is:⁹

An aquifer, or a portion of an aquifer, that meets the criteria for a USDW, for which protection under the SDWA has been waived by the UIC Program. Under 40 CFR Part 146.4, an aquifer may be exempted

3 EPA defines a USDW as “An aquifer or portion of an aquifer that supplies any public water system or that contains a sufficient quantity of ground water to supply a public water system, and currently supplies drinking water for human consumption, or that contains fewer than 10,000 mg/l total dissolved solids and is not an exempted aquifer.” See: www.epa.gov/ogwdw/uic/glossary.html#u

4 EPA Underground Injection Control Program: Classes of Wells. <http://www.epa.gov/safewater/uic/wells.html> (18 March),

5 Ibid.

6 Ibid.

7 Ibid.

8 Dougherty, C. C.; MacLean, B., Using Class V Experimental Technology Well Classification for Pilot Geologic Sequestration Projects - UIC program Guidance (UICPG #83). In Office of Groundwater and Drinking Water, O. o. A. P., Ed. 2007.

9 See EPA's definition of an exempted aquifer at: www.epa.gov/ogwdw/uic/glossary.html#e

if it is not currently being used—and will not be used in the future—as a drinking water source, or it is not reasonably expected to supply a public water system due to a high total dissolved solids content. Without an aquifer exemption, certain types of energy production, mining, or waste disposal into USDWs would be prohibited. EPA makes the final determination on granting all exemptions.

The current UIC provides important experience relevant to regulating GS, including experience with the injection of CO₂, injection of large volumes of fluids, injection of buoyant fluids, and injection of fluids requiring long-term containment:

- Approximately 48 million tons of mostly naturally produced CO₂ are injected annually by Class II wells for EOR operations in the U.S.,¹⁰

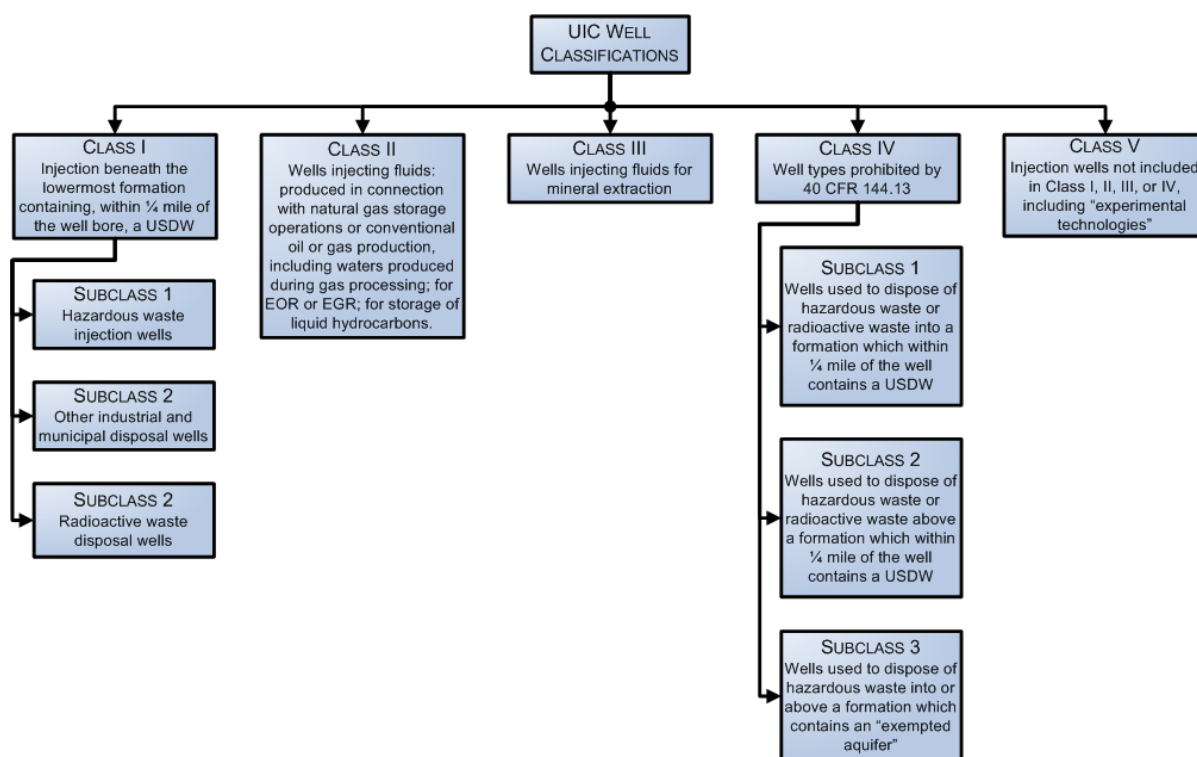


Figure 6.1: The five well classes that currently exist under the Federal/state Underground Injection Control (UIC) Program.

¹⁰ DOE, U. *Carbon Sequestration Through Enhanced Oil Recovery* National Energy Technology Laboratory: 2008; www.netl.doe.gov/publications/factsheets/program/Prog053.pdf

“In much of the country, states are central to implementation and enforcement of UIC rules.”

- Approximately 3 billion tonnes of municipal wastewater are injected by Class I non-hazardous wells in Florida each year,¹¹ and a similar volume of oilfield brines are injected by Class II wells annually in the U.S.¹² This is an amount larger than the nearly 2.3 billion tonnes of CO₂ emitted by the whole U.S. electric power sector in 2006;¹³
- Municipal wastewater injected in Florida is less dense than the saltwater it displaces in the injection zone; and,
- Applicants for a Class I well permit who intend to inject hazardous waste must show that the waste will not migrate for 10,000 years; though the other types of Class I wells have no such requirement.¹⁴

In much of the country, states are central to implementation and enforcement of UIC rules. States apply for primary enforcement authority by demonstrating that the state UIC program is:¹⁵

at least as stringent as the federal standards; the state, territory, or tribal UIC requirements may be more stringent than the federal requirements. (For Class II, states must demonstrate that their programs are effective in preventing pollution of USDWs).

EPA may grant primacy for all or part of the UIC program, e.g., for certain classes of injection wells. Currently, 33 states have primacy, seven share authority with the EPA, and 10 have UIC programs run by the EPA, as shown in Figure 6.2. In the majority of states with shared authority, state oil and gas regulators have primacy for Class II wells, while EPA has authority for other classes of wells. It is also worth noting that in states with primacy, state oil and gas regulators generally oversee Class II wells, whereas the other well classes are overseen by environmental or natural resource regulators.

Florida’s experiences with the injection of municipal wastewater under the UIC program offers a number of notable lessons. Despite the procedural requirements for Class I well construction and operation, injected wastewater did migrate upward into overlying drinking water aquifers. In response, the EPA promulgated new regulations that allowed injection to continue if advanced wastewater treatment was implemented.¹⁶ This situation, where the

11 Keith, D. W.; Giardina, J. A.; Morgan, M. G., et al., Regulating the Underground Injection of CO₂. *Environmental Science and Technology* 2005, 39, 499A - 505A.

12 Wilson, E. J.; Johnson, T. J.; Keith, D. W., Regulating the Ultimate Sink: Managing the Risks of Geologic CO₂ Storage. *Ibid.* 2003, 37, 3476-3483.

13 Environmental Protection Agency *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2006*; US Environmental Protection Agency: Washington D.C., 2008.

14 40 CFR §148.20

15 See: <http://www.epa.gov/ogwdw/uic/glossary.html#p>

16 Keith, D. W.; Giardina, J. A.; Morgan, M. G., et al., Regulating the Underground Injection of CO₂. *Environmental Science and Technology* 2005, 39, 499A-505A.

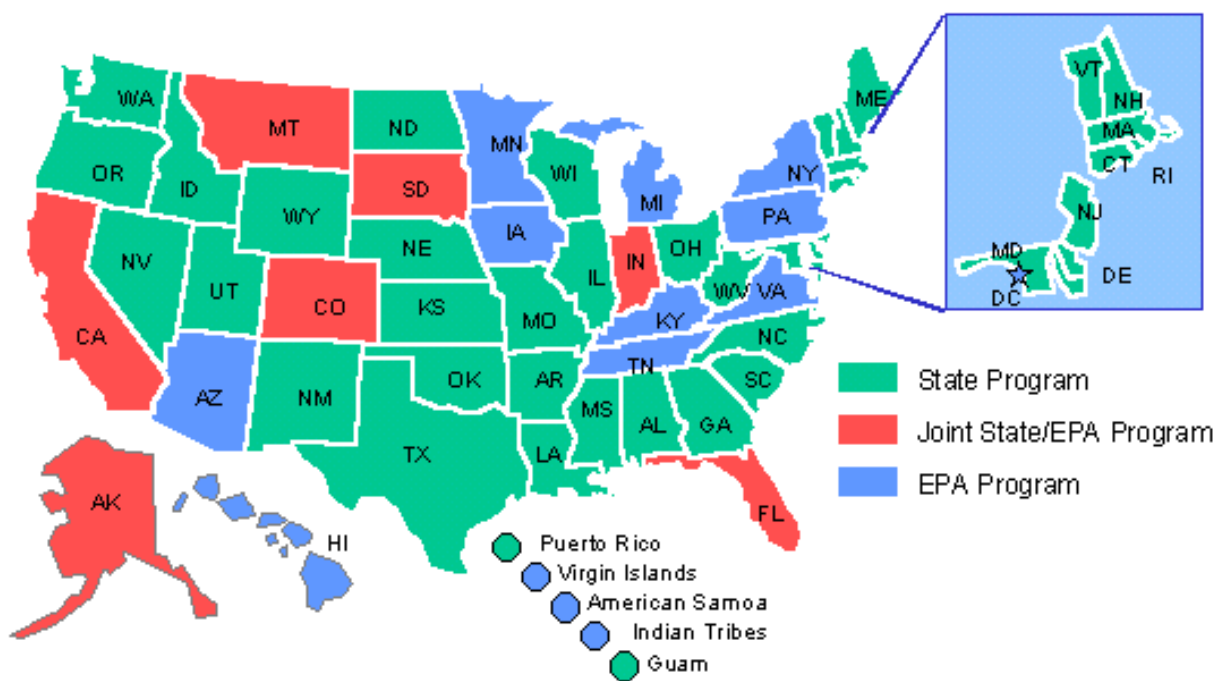


Figure 6.2: In much of the U.S., states are responsible for administration of the UIC program (green). In the case of six states (red), implementation is jointly handled between the state and the EPA. In the balance of the country (blue), the EPA administers the program directly. Image from <http://www.epa.gov/ogwdw/uic/primacy.html>.

Agency was forced to develop an exception after the fact when injection did not meet performance standards, but the community depended on the injection activity, should be avoided for GS. However, the approach used by the EPA to solve the problem—i.e., applying an adaptive, performance based standard instead of a strict no-migration standard—deserves consideration for inclusion as part of a regulatory framework for GS. This experience also shows the value of monitoring: the problem was detected because Florida has monitoring standards more stringent than most other states.

EPA’s Proposal to Create Class VI Wells: After conducting a series of workshops over the course of the last several years, the U.S. EPA released a draft rule for GS wells in the summer of 2008 that proposes creation of the Class VI well category.¹⁷ Class VI rules would apply only to wells that inject CO₂ for geological sequestration. Wells injecting CO₂ for EOR would remain

“Florida’s experiences with the injection of municipal wastewater under the UIC program offers a number of notable lessons.”

Class II wells. The proposed rules require that all GS wells inject beneath the deepest USDW. They propose construction requirements for GS wells similar to those for Class I hazardous waste disposal wells, including use of materials compatible with the CO₂ stream. They would require that a permit applicant submit:

- information on the site geology and hydrogeology;
- proposed operating conditions;
- a review of all wells in the area of review (AoR) that penetrate the injection or confining zone, and plans for corrective action on any wells that could serve as conduits for CO₂ leakage;
- injection well testing plans;
- monitoring plans;
- emergency and remedial response plans;
- plans for plugging the injection wells when injection ends; and,
- post-injection site care and site closure plans.

The AoR is the region that may be impacted by CO₂ injection, based on both the maximum extent of the CO₂ plume and the area where pressure differentials caused by injection could cause movement of fluids into a USDW. The EPA proposes that the extent of this region be calculated by numerical modeling of the subsurface.¹⁸

In addition, an applicant for a Class VI permit will have to demonstrate financial responsibility and resources for corrective action, injection well plugging, post-injection site care, and site closure.

Proposed requirements for Class VI wells differ in several ways from requirements for other well classes. First, rather than having the size of the area of review (AoR) fixed during the permitting process, the proposed Class VI rule requires that operators periodically reevaluate the AoR during injection operations, comparing modeling projections with monitoring results. This allows regulators and operators to adapt based on actual conditions as a project proceeds. Second, it allows phased corrective action on wells located within the AoR. Corrective action consists of plugging all inadequately sealed wells that might be a pathway for CO₂ to leak out of the injection zone. Because the AoR for a geological sequestration project may be quite large, this approach allows an operator to fix wells closest to the injection site first, and then gradually work outward, always staying ahead of the expanding CO₂ plume and induced brine movements. Third, the proposed Class VI rules require that after injection is finished, the operator must continue to monitor the site and

18 While there is discussion of a "pressure front," in fact, in most formations, the pressure will decrease in a continuous manor, with no discrete "front."

provide financial assurance until the injected CO₂ is stable and poses no risk. EPA proposes that the post-injection period last 50 years, but with discretion to adjust the length based on site performance.

While the proposed Class VI rules are designed to prevent geological sequestration of CO₂ from harming groundwater, the EPA notes in the preamble to the rule¹⁹ that, because the statutory authority for the UIC Program comes from the Safe Drinking Water Act, the agency is unable to address other critical issues that must be resolved for geological sequestration, such as:

- potential human health or ecological impacts if carbon dioxide leaks to the surface or near-surface (discussed in Chapters 1 and 4 of this report);
- ownership of pore space (discussed in Chapter 5 of this report);
- long-term liability (discussed in Chapter 7 of this report); and,
- greenhouse gas accounting, which will be the enabling link to incentive structures that make geological sequestration economically viable (discussed in Chapters 9 and 10 of this report).

The preamble to the proposed UIC rule argues that by protecting groundwater it will effectively regulate other risks because in nearly all geologic situations, groundwater stands between the sequestration reservoir and the surface.²⁰

Others express concern that risk assessments performed under the UIC will not characterize the risk of surface leakage, a topic that is of concern to the public. EPA has been collecting public comments on their proposed rule. Those should become publicly available at about the same time as this report appears.

The Role of the States in Regulating GS: The regulatory context for geological sequestration is shaped by a strong history of state and local control of land use issues, importance of property rights, and significant variation in geology and state law (see Chapter 5). State regulators, who have valuable local knowledge, will likely play a role in permitting of geological sequestration projects. Three types of state agencies have experience directly relevant to regulation of geological sequestration:

- Underground injection control regulators (40 states have primacy or shared primacy).
- Natural gas underground storage regulators (33 states have natural gas storage facilities. Underground natural gas storage is exempted from UIC regulations).
- Oil and gas regulators (37 states are members or associates of the Interstate Oil and Gas Compact Commission, IOGCC). In 2007

“...because the statutory authority for the UIC Program comes from the Safe Drinking Water Act, the agency is unable to address other critical issues that must be resolved for geological sequestration...”

¹⁹ 73 FR 43,495

²⁰ Note that there are a few wells in California where there is no USDW in the subsurface. In these cases, the UIC still regulates the injection.

the IOGCC published a model statute and general regulations for geological sequestration that presents specific legislative and rulemaking language designed to be adopted by individual states. The IOGCC proposal is predicated on CO₂ being a “valuable commodity,” the sequestration of which should be regulated exclusively at the state level.²¹

States are pushing ahead to establish state-level geological sequestration regulations. Washington has adopted GS rules, Kansas has proposed rules, and four other states have task forces exploring rules for geological sequestration.

Table 6.1: Summary of state geologic sequestration regulatory initiatives.

State	Policy	Year	Description
Kansas	HB 2419	2007	Requests agency establish rules for geologic sequestration. Creates fund to pay for regulatory costs, remediation, long-term stewardship.
	KAR 82-3-1100-1120	under review	Sets requirements for CO ₂ storage facility operating permits.
Massachusetts	SB 2768	2008	Instructs agency to set sequestration definitions and standards.
New Mexico	EO 2006-69	2006	Requires agency to study statutory and regulatory requirements for GS.
Oklahoma	SB 1765	2008	Declares CO ₂ a commodity. Declares existing rules apply to EOR. Creates a task force to make recommendations on CCS.
Utah	SB 202	2008	Task force to recommend rules for GS by January 1, 2011, interim report by July 1, 2009.
Washington	ESSB 6001	2007	Authorizes agency to set rules for GS. Specifies that GS can be used to meet GHG emission reduction goals.
	WAC 173-218-115	2008	Revises Washington UIC rules for GS.
	WAC 173-407-110	2008	Sets performance standard for GS.
Wyoming	HB 0089	2008	Declares pores space the property of surface owner.
	HB 0090	2008	Agency to propose rules for GS permitting, no set date. Working group to recommend financial assurance and post closure care requirements by September 30, 2009.

The evolving state rules represent significantly different approaches to regulating geological sequestration of carbon dioxide. The Washington state rules implement the state’s UIC program for GS wells. They are broader in scope than the proposed EPA Class VI well rules, because they are coupled with a strong state climate policy, and are therefore able to include strong links

²¹ IOGCC *Storage of Carbon Dioxide in Geological Structures: A Legal and Regulatory Guide for States and Provinces*; Interstate Oil and Gas Compact Commission: Sept 25, 2007; http://www.iogcc.state.ok.us/news_pubs.aspx.

to greenhouse gas reductions. Kansas' rules treat GS as a unique activity, under the authority of stand-alone GS legislation that also clarifies responsibility and funding for post-closure site care. The Kansas rules would permit storage rather than injection, and Kansas would require only a storage permit, not separate UIC injection permits for GS facilities.

Comparison of these early state GS regulations shows that while they agree in some areas, they disagree on some important issues. Consensus is emerging that: protection of groundwater is paramount; pressure effects from CO₂ injection are important; monitoring should include testing in the injection zone and the first permeable formation overlying the confining zone; and, site performance should be a factor in determining the length of the post-injection period. Regulatory discrepancies are emerging regarding the allowable composition of the CO₂ stream, the size of the area of review, reservoir performance goals, and management of risks other than those to groundwater. It is unclear how these state GS regulatory initiatives will fit into a national GS regulatory framework.

6.2 Approaches for Regulating Geologic Sequestration Operations

Before exploring potential institutional arrangements for regulating the operation of GS projects, it is useful to consider the attributes that could help give a GS regulatory framework the ability to achieve the objectives outlined in Box 4.1. In our view, GS regulation stands a better chance of success if it is adaptive and able to balance multiple environmental objectives.

Adaptive Approaches: After experience has been gained with a set of early projects (see Chapters 4 and 11), and a regulatory framework has been put in place, regulation should set realistic objectives and be flexible, yet firm, about how they are accomplished. Objectives should be technically realistic to achieve and verify, and, as discussed below, they must incorporate the ability to balance conflicting environmental objectives. For example, a strict no migration requirement (as with UIC Class I wells) would not form the basis for adaptive regulation. Project level flexibility should be structured such that it provides confidence to communities that safety is paramount, and confidence to project operators and investors that regulators won't pull the plug on a project that is following the rules, not causing safety concerns, but running into unexpected geological conditions that require some changes in project strategy. Because of the irreducible uncertainties associated with reservoir engineering, it is reasonable to expect that sequestration site performance during commercial injection will deviate in some respects from projections. Adaptive regulation should be able to distinguish between "surprises" that are benign, those that require minor adjustments to operating or monitoring plans,

“Adaptive regulation should give regulatory certainty to individual projects, while providing a means to gather, digest, and implement new knowledge generated by the ongoing operation of growing numbers of GS sites.”

and those that are dangerous and require regulatory intervention.

How could a regulatory framework be designed to be adaptable at the project level? Three key elements are: realistic objectives, performance based rules, and mechanisms for adjusting permit conditions based on operating experience at the site. Performance based regulation uses rules that hold operators responsible for meeting environmental objectives without detailed procedural specifications for such things as well construction. Such an approach is inherently more adaptable than the command and control approach that has dominated U.S. environmental regulation. If regulations for GS specify performance objectives, rather than detailed procedures, they would be applicable to a wide range of sequestration geologies and project types. Mechanisms for adjusting permit conditions would allow regular review to adjust the intensity of such things as monitoring or reporting, based on the actual performance of the site. So as not to change the rules in the middle of the game, these adjustments should be based on specific thresholds, established in the permit and made clear to both the operator and the public. Issues that might be addressed include the level or nature of migration or leakage would require additional monitoring or remedial action, and the levels of predictable behavior and containment could qualify the site for simplified monitoring or reporting.

Adaptive regulation should give regulatory certainty to individual projects, while providing a means to gather, digest, and implement new knowledge generated by the ongoing operation of growing numbers of GS sites. Some argue that the multiple amendments to the Clean Air Act represent an adaptive approach to program improvement, but we believe this model is too unwieldy. Instead, we are inclined to favor setting up a body to review findings from pilot and early-mover projects and revise the rules at set intervals (see discussion in Chapters 4 and 11). Rule changes would apply only to new permits; ongoing GS operations would continue under their existing permit terms.

An adaptive process must also give investors the certainty required to make large investments into CCS projects, because development and operation of commercial GS projects will involve investments of hundreds of millions of dollars. Project developers must have confidence that, should the observed behavior of CO₂ in the subsurface be different than initially modeled, the regulator will not unilaterally “pull the plug” on their project. Thus, the concept of learning-by-doing should be acknowledged in the regulation—that is, operators should be encouraged to learn about the behavior of the injected CO₂ in their project and be able to adapt their plans to safely manage unexpected behavior without the threat of having their permits canceled. Additionally, the thresholds that would result in the regulator requiring

remediation or pulling the plug should be well established and clear to both the operator and the public.

Approaches that Balance Multiple Environmental Objectives: If CCS regulation is to successfully facilitate widespread deployment of CCS as a means of reducing greenhouse gas emissions, it will need to balance impacts of sequestration with those of climate change. Currently, one obvious difficulty of pursuing this approach is that controlling GHG emissions to reduce the risk of climate change is not yet recognized in federal legislation as a national objective. Two areas where this ability to consider tradeoffs will be vital is in addressing potential impacts to groundwater and leakage to the atmosphere.

Protection of drinking water is an essential environmental goal, but so is avoiding the dangerous impacts of climate change. These goals may sometimes be complimentary. For example, the 2007 IPCC Working Group II report concluded that climate change presents significant risk to groundwater as rising sea levels extend areas of salinization and increased precipitation variability decreases recharge to groundwater.²² At other times, these goals may conflict: for example, strict prohibition of any impacts to groundwater may inhibit CCS deployment and exacerbate climate change.

As mandated by the SDWA, the rules of the Underground Injection Control Program (UIC) have been developed to give primacy to the objective of preventing any migration of injected fluid or other contaminants into underground sources of drinking water (USDWs). In practice, however, the situation has been less clear-cut. For example, the experience in Florida, discussed earlier in this Chapter, suggests that it would be highly desirable to have arrangements in place ahead of time to balance conflicting national environmental interests, rather than to temporize, and adjust regulations to rationalize the situation.

EPA's proposed rule for Class VI wells specifies that CO₂ injected under the rule (if adopted as proposed) must have sufficiently low concentrations of impurities, such as H₂S, so as not be considered a hazardous waste.²³ The Agency's motivation for this proposed restriction is to reduce the risk of corrosion of well equipment and cement, and also to minimize the potential for contamination of USDWs—which is sensible. However, there may be some circumstances under which, with adequate engineering design, injecting the impurities along with the CO₂ might be a better overall environmental solution than separating them and having to dispose of a more concentrated waste stream. It would be wise to consider whether and how such a trade-off might be made.

“Protection of drinking water is an essential environmental goal, but so is avoiding the dangerous impacts of climate change.”

²² Parry, M.; Canziani, O. F.; Palutikof, J., et al., *Climate Change 2007: Impacts, Adaptation and Vulnerability. Contribution of Working Group II to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*. Cambridge University Press: Cambridge, U.K., 2007; p 976.

²³ Where the term “hazardous waste” is defined in 40 CFR 261.

One other issue that requires careful consideration is leakage of CO₂ back to the atmosphere (see Chapter 4). The recent IPCC Special Report on CCS makes it clear that, for a well planned and operated project (i.e., the only kind that should receive regulatory approval), the probability of sudden large leakage is effectively zero and the probability of even very small slow leakage is extremely low.²⁴ The IPCC summarized their views as follows:²⁵

With appropriate site selection based on available subsurface information, a monitoring programme to detect problems, a regulatory system and the appropriate use of remediation methods to stop or control CO₂ releases if they arise, the local health, safety and environment risks of geological storage would be comparable to the risks of current activities such as natural gas storage, EOR and deep underground disposal of acid gas.

However, given the uncertainties that are inherently associated with characterizing geological structure a kilometer or more underground, there is always the possibility that over time, some small slow leakage may occur. As the discussion in Chapter 4 makes clear, given the very low levels that are likely and current technology, detecting such leakage may be technically impossible. Nonetheless, positing that detection becomes possible, what should be the basis for pulling the plug on an operating project?

It is essential to assure safety for all activities on the surface (including, for example, assuring that dangerous levels of CO₂ do not build up in the basements of homes). However, as noted in Chapter 4, there are parts of the world that safely and routinely live with larger surface fluxes of CO₂ than are likely to occur from well designed GS projects. If a route of slow seepage is identified, it may in some cases be possible to take remedial action to stop or significantly slow the flow rates. The current EPA draft discusses remediation only in the context of leakage to USDWs via wells—operating or abandoned. Natural structures, such as transmissive faults or fractures, may also be identified that might require remediation via grouting, CO₂ extraction, aquifer pressure modification, or other strategies. Such options should be pursued when that can be done at a reasonable cost.

At the same time, given that the choice may be between 100% leakage (i.e., immediately up the stack of a power plant) or some small amount of leakage (e.g., less than 1%) over the life of a sequestration project, it may sometimes be desirable in terms of net social benefit, to let a project continue if the impacts of leakage are otherwise manageable. This is a situation in which a

²⁴ Benson, S.; Cook, P.; Anderson, J., et al., Underground geological storage. In *IPCC Special Report on Carbon Dioxide Capture and Storage*, Metz, B.; Davidson, O.; de Coninck, H.; Loos, M.; Meyer, L., Eds. Cambridge University Press: Cambridge, U.K., 2005.

²⁵ Ibid.In.

balancing of national (and international) environmental objectives may arise, and where the ability to be adaptive as a project proceeds may be essential to the feasibility of a CCS project.

Approaches That Create a Clear Pathway for Transition From EOR to GS:

Regulations for sequestration site permitting should create a clear path by which pilot and early-mover projects permitted as UIC Class V wells, and CO₂-flood enhanced oil recovery (EOR) projects permitted as UIC Class II wells, to become commercial sequestration projects under new regulations. This could be accomplished by making it clear that EOR projects seeking credit for sequestration should be subject to the same set of performance objectives as new sequestration sites. In addition, monitoring and reporting requirements could be established for EOR sites that wish to be eligible for crossover.

6.3 Options For a Regulatory Framework for Geologic Sequestration Site Permitting

The CCSReg project is not yet prepared to make recommendations on institutional arrangements that could best facilitate an adaptive framework and allow risks to water and climate be balanced. Potential solutions fall into two broad categories: modifications to the UIC program under authorization provided by the SDWA; or, freestanding GS rules, promulgated under new authorizing legislation. Under either of these systems, there is the further question of how regulation of GS site operations should be balanced between federal and state agencies.

Modifications to the UIC Program: Advantages of building a GS regulatory framework that adapts existing EPA UIC regulations include the ability to capitalize on the program's experience, its relationships with state regulators, and the knowledge about GS it has amassed in preparing the proposed Class VI regulations. Modifications to existing rules might be made more quickly than the alternative process of passing new legislation and then writing new rules.

However, using the UIC program as a basis for regulating GS operations has significant limitations. Because of the constraints of its statutory mandate, the UIC program cannot comprehensively manage all potential issues that arise in connection with GS operations, and, because it places protection of drinking water aquifers (independent of quantity or depth) above all other objectives, it cannot address tradeoffs between risks to groundwater and risks from climate change. Furthermore, because the UIC program is built largely on procedural rules, it lacks the flexibility to offer a truly adaptive approach, and thus runs the risk of locking in features now that will ultimately inhibit widespread

“...using the UIC program as a basis for regulating GS operations has significant limitations.”

commercial CCS deployment.²⁶ If it were decided to use the UIC as the basic approach, then a number of modifications beyond those proposed in the draft Class VI well rules deserve consideration:

1. Federal legislation to institute the control of CO₂ and other greenhouse gasses (GHGs) should also modify the Safe Drinking Water Act (SDWA) to allow the EPA to balance impacts to groundwater with those that may be imposed by continuing emissions to the atmosphere. If control of GHGs is achieved via administrative action (e.g. by declaring them pollutants under the Clean Air Act), legislation would still be needed to modify the SDWA. Such legislation could further address these issues through at least one of three mechanisms:
 - Establish an internal administrative mechanism to balance the (potentially conflicting) national environmental interests in protecting USDWs and minimizing the release of CO₂ to the atmosphere.
 - Create a mechanism by which an Administrative law judge can hear and resolve conflicts when an injecting party finds themselves stuck between parts of the EPA responsible for administering the UIC program and parts of the EPA (or elsewhere) responsible for regulating CO₂ emissions.
 - Create some kind of standing expert review board charged with reviewing and balancing national environmental interests in protecting USDWs, minimizing the release of CO₂ to the atmosphere, and avoiding significant risk to human health, safety, and ecosystems.
2. A clear, predictable pathway could be created for sites to transition from EOR to pure GS. This could include amending Class I, II and V rules to require monitoring and verification activities for any project that wishes to be eligible for future crossover. It might also involve making the well construction requirements for Class VI wells less prescriptive and more performance based.
3. The relationship between Federal and state oversight could be reassessed. Possible alternative arrangements include:
 - Continue to operate in a split mode with primary enforcement authority delegated to some states (and tribes) for Class VI wells, and handled by a Federal agency for others. Develop mechanisms (such as interstate compacts) to handle the issues identified above.
 - Retain the option to delegate primary enforcement authority for Class VI wells to states, but, to assure uniform treatment, either provide

²⁶ Wilson, E. J.; Morgan, M. G.; Apt, J., et al., Regulating the Geological Sequestration of Carbon Dioxide. *Environmental Science and Technology* 2008, 42, (8), 2718–2722.

that uniform regulations are adopted by the affected states or add a provision that allows site operators to move the jurisdiction to a Federal agency when conflicts arise or when a site crosses state boundaries.

- Develop a hybrid system in which states that have received primary enforcement authority for other well types, and want to be involved in approval and licensing of Class VI wells, do so in a joint arrangement with a designated Federal authority.
- Retain the approval and licensing of all Class VI wells as the direct responsibility of the EPA, while responsibility for all other well types can (continue to) be delegated to states (or tribal regions).

Clearly, several of these arrangements would require modifications of the existing legislation under which the UIC operates.

Freestanding GS Rules, Promulgated Under New Authorizing Legislation:

Starting afresh has many advantages. A fundamental choice will be whether to use an environmental agency or a natural resource agency as the vehicle for site operations permitting. Worldwide, the trend is to give permitting authority to a natural resources agency, with an environmental agency delegated to oversee monitoring.²⁷ New authorizing legislation could create a GS operations permitting system with the authority to manage all risks, not just risks to groundwater. Programmatic links to greenhouse gas reductions could be made explicit. Commercial issues, such as mechanisms for granting exploration permits or administering unitization of GS formations, could be addressed, and interactions between GS operations and oil and gas operations could be handled directly. New authorizing legislation—by uncoupling GS from the UIC pathway—could offer the opportunity to set up more performance based, adaptive permitting rules, with mechanisms for balancing conflicting environmental interests built in from the start. Starting fresh also offers potential advantages not just for permitting site operations, but also for dealing with issues of property rights (Chapter 5) and long-term stewardship (Chapter 7). Of course, building a GS permitting system with new authorizing legislation also has disadvantages. It is contingent on the nation having the political will to enact both climate change policy and legislation enabling advanced coal technologies with CCS as a means of achieving GHG reduction goals. Politically, this is a complex equation requiring a willingness to compromise between states and regions that is not yet in evidence in the U.S.²⁸ The uncertainty of accomplishing this approach, ambiguity about what might

“New authorizing legislation ... could offer the opportunity to set up more performance based, adaptive permitting rules, with mechanisms for balancing conflicting environmental interests ...”

²⁷ In the Netherlands, the onshore Shell project at Barendrecht is being permitted under Mining Law (Van Klaveren, 2008). In Alberta Canada, EOR and acid gas injection is permitted by the Energy Resources Conservation Board, an oil and gas regulator. In Victoria, Australia, GS site permitting is proposed to be through the Department of Primary Industries, a mining and oil and gas regulator (see appendix A)

²⁸ Pollak, M.; Johnson, J.A.; Wilson, E.J. *The Geography of CCS Regulatory Development in the U.S.* In 9th International Conference on Greenhouse Gas Control Technologies, Washington, DC, 16-20 November 2008.

emerge from the inevitable process of political compromise, and the possibility that it would take a long time could discourage utilities and their commercial backers from making investments in CCS.

If the route chosen is a new framework under new authorizing legislation, there are a number of institutional design issues that should be considered.

1. Ideally, legislation enabling GS site permitting should be enacted simultaneously with (or subsequent to) federal climate change policy. This could facilitate a regulatory framework that can balance conflicting environmental objectives, and manage commercial concerns, such as links to carbon credits and fair opportunity for market entry.
2. A new system could be state-based or a federal system with certain authorities delegated to the states (similar to the current UIC program). However, a state-centric approach would likely need to be supplemented by creation of a mechanism to manage inter-state coordination for GS sites that span state boundaries. Moreover, as discussed in Chapter 7, there is the additional problem that states will likely have difficulty doing effective risk pooling for long-term care. The IOGCC has developed a proposal that embodies the concept of a purely state-based system.²⁹ Under this model, new enabling legislation, passed by individual states, creates an overall permitting system for site operations that incorporates UIC rules (administered by a state agency that has been granted primacy). Kansas has taken this path. This approach builds on the experience and local knowledge of state regulators, and can be put into place relatively promptly by states that wish to do so, but in the longer run, will encounter the limitations outlined above. In short, new federal legislation could give direction and consistency, and create mechanisms for inter-state coordination.
3. A two-stage approach could be pursued, wherein the UIC program continues to permit wells injecting CO₂ for a set period of time, but new legislation establishes a commission charged with gathering results from pilot projects and providing recommendations to Congress on the form for regulation of widespread commercial GS.³⁰ As discussed in Chapters 4 and 10, we believe that such a two-stage approach has much to recommend it.

Possible Citizen Suit Provision: A citizen suit provision can be an effective component of a comprehensive liability scheme in order to assure diligent application and enforcement of regulations, and to discourage operators from assuming (or expecting) imperfect regulatory vigilance. With a citizen suit

²⁹ IOGCC *Storage of Carbon Dioxide in Geological Structures: A Legal and Regulatory Guide for States and Provinces*; Interstate Oil and Gas Compact Commission: Sept 25, 2007; http://www.iogcc.state.ok.us/news_pubs.aspx.

³⁰ Wilson, E. J.; Morgan, M. G.; Apt, J., et al., Regulating the Geological Sequestration of Carbon Dioxide. *Environmental Science and Technology* 2008, 42, (8), 2718–2722.

provision, a private actor who either is or might be adversely affected by any violation of a regulatory requirement is empowered to bring a legal claim against the person or entity responsible for the regulatory breach. This includes claims against the United States and any other (state or federal) government instrumentality or agency (as well as the agency's administrator) when there is an alleged failure to enforce regulations or perform any other nondiscretionary act or duty.

Citizen suit provisions have been included in a number of other regulatory systems, and should, at least, be considered for inclusion in freestanding GS legislation. Such a provision would apply during the operational and post injection phases of the geologic sequestration lifecycle. The objective would be to provide additional safeguards to ensure that regulatory agencies are meeting their obligations to enforce the relevant regulations.

To ensure that GS projects do not end up embroiled in litigation that proves baseless, any citizen suit provision should include an appropriate gate-keeping mechanism. Claimants should be obliged to give the relevant regulatory agency and injection operator notice of their intentions to pursue a cause of action. This would allow the agency a reasonable opportunity to determine the credibility of the claim and decide whether to devote its own resources to pursuing the alleged violation. A notice requirement would also help minimize unmeritorious citizen suit claims by affording a GS project operator the opportunity to seek corrective action and remedy the problem before litigation commences. Three decades of experience with such provisions in other contexts³¹ may offer some guidance on the degree to which citizen-suit provisions 1) enhance good performance, 2) improve public acceptance, and 3) deter investment, however that will require further research to assess.

At present, our inclination is to recommend the two-stage approach for the regulation of sequestration, using modifications to the UIC program for early projects, but seeking a new federal statute that considers all sequestration activities in an adaptive framework that balances all relevant environmental impacts (water, climate, etc.). States would likely continue to play a significant role in oversight and implementation under the two-stage approach, particularly for EOR-related sequestration activities.

Before making any final recommendation on the options for a regulatory framework and the level of state involvement, we welcome advice and guidance on these and other alternatives.

³¹ Among federal statutes, the RCRA statute discussed above, the Clean Air Act, the Endangered Species Act, the Clean Water Act and, in other realms, the Americans with Disabilities Act and the Fair Housing Act, all vest standing in private citizens to pursue litigation alleging violation of the legislation's standards.

Chapter 7: Long-term Stewardship

Once injection of CO₂ has stopped at a sequestration site and the site has been appropriately closed, some entity must be responsible for oversight of the facility on a permanent basis. This oversight is referred to as “long-term stewardship.”

In most cases, long-term stewardship will be a relatively simple activity involving occasional monitoring and measurement activity to assure that injected CO₂ is stable and behaving as expected. In the event that CO₂ behaves in ways not anticipated and presents risks to human health, the environment, or other resources, responsibilities would include a variety of remedial activities (see Box 7.1). Dealing with these circumstances requires a clear prior understanding of what entity will undertake these activities, what entity is financially liable for these activities, and how any additional liabilities will be allocated.

To briefly reiterate the discussion in Section 4.3, geologists argue that if difficulties arise with a completed project, they are most likely to occur during the first few decades after closure (see Figure 4.4). The risks posed by geologic sequestration are driven by the buoyancy of the injected CO₂ and the increased pressure in the receiving formation. As the various trapping mechanisms discussed in Section 4.3 come into play, the probability that CO₂ will move to places where it does not belong, or cause other problems, can be expected to fall (see Figure 4.3).

When several injection projects are operating in one large geological formation (or basin) long-term stewardship for a closed out site may have to deal with possible interactions and influences caused by other near-by active injection fields.

This chapter discusses five possible alternative strategies to manage the financial liability associated with long-term stewardship:

1. Traditional bonding and insurance approaches.
2. A wholly private-sector solution.
3. States assume responsibility for sites within their borders.
4. Federal responsibility for all sites.
5. A hybrid private-public solution.

All of these models must provide some mechanism in place to verify that the injected CO₂ remains in the subsurface sequestered from atmosphere if the injected CO₂ is being traded in a national or international emissions trading market. This issue discussed further in Section 7.7.

“... if difficulties arise with a completed project, they are most likely to occur during the first few decades after closure.”

Box 7.1: Remedial actions to respond to unexpected problems

One of the most likely pathways for leakage of CO₂ to the surface (or into overlying strata) is through abandoned wells.^{1,2} Should such a leak develop, both real world observations and modeling suggest that, in most cases, leakage rates would be relatively low and unlikely to pose a significant risk to people or ecosystems at the surface.^{3,4} Nonetheless, it is important that such leaks are detected and repaired to minimize risks from leakage at the surface and ensure that minimal amounts of CO₂ leak back to the atmosphere. Depending on the leakage magnitude and path (e.g., between the casing and cement, through the casing, etc.), there are a number of techniques that can be applied to remediate leakage from abandoned or active wells:⁵

- Applying standard oil & gas recompletions techniques to replace well components.
- Squeezing cement behind the well casing (i.e., between rock and the outermost well tubing).
- Plugging and abandoning active injection wells that can not be repaired using these techniques.
- Stopping blowouts using standard techniques to “kill” a well such as injecting a heavy mud to stop the upward flow of CO₂. Once control of the well is regained, the approaches above can be used for remediation.

Other techniques exist for remediating leakage of CO₂ from the sequestration reservoir through geological features, such as faults and fractures, to overlying strata, groundwater, shallow unsaturated soil (i.e., the vadose zone), indoor environments, and surface waters. These techniques may involve: reversing pressure gradients in the reservoir by withdrawing brine from one location and injecting it at another; reducing pressure in the aquifer by ceasing injection and withdrawing CO₂; or by accelerating dissolution of CO₂ near the feature.^{6,7,8}

7.1 Traditional Bonding and Insurance Approaches

This strategy is based on the approach taken in the UIC injection rules primarily for Class I wells injecting hazardous materials.

Under the current UIC regulations,⁹ the operator is required to provide a plan for plugging and abandonment, estimate the cost of plugging and abandonment, and ensure funds are available for plugging and abandonment at the time of permitting. Both bonding (e.g., surety bonds, letters of credit, etc.) and insurance mechanisms (including both self and third-party insurance) are available to the operator. Once the operator plugs the well (as specified in the regulation)¹⁰ and files the necessary paperwork, the regulator releases the financial guarantee.¹¹ The well is then recorded as ‘plugged and abandoned,’ and information is kept on file. In addition, the designated UIC director can

1 Celia, M. A.; Bachu, S. *Geological sequestration of CO₂: is leakage unavoidable and acceptable?*, In 6th International Conference on Greenhouse Gas Control Technologies, Kyoto, Japan, 1-4 October 2002, 2002; Gale, J.; Kaya, Y., Eds. PERGAMON.

2 Benson, S.; Cook, P.; Anderson, J., et al., *Underground geological storage*. In *IPCC Special Report on Carbon Dioxide Capture and Storage*, Metz, B.; Davidson, O.; de Coninck, H.; Loos, M.; Meyer, L., Eds. Cambridge University Press: Cambridge, U.K., 2005.

3 Bogen, K.; Burton, E. A.; Friedmann, S. J., et al. *Source terms for CO₂ risk modeling and GIS/simulation based tools for risk characterization*, In 8th International Conference on Greenhouse Gas Control Technologies, Trondheim, Norway, 19-22 June 2006, 2006; Elsevier Science.

4 Wilson, E. J.; Friedmann, S. J.; Pollak, M. F., *Research for deployment: Incorporating risk, regulation, and liability for carbon capture and sequestration*. *Environmental Science & Technology* 2007, 41, (17), 5945-5952.

5 Benson, S.; Hepple, R., *Prospects for early detection and options for remediation of leakage from CO₂ Storage Projects*. In *The CO₂ Capture and Storage Project (CCP) for Carbon Dioxide Storage in Deep Geologic Formations for Climate Change Mitigation*, Benson, S., Ed. Elsevier Science: 2005; Vol. 2.

6 Ibid.

7 Benson, S.; Cook, P.; Anderson, J., et al., *Underground geological storage*. In *IPCC Special Report on Carbon Dioxide Capture and Storage*, Metz, B.; Davidson, O.; de Coninck, H.; Loos, M.; Meyer, L., Eds. Cambridge University Press: Cambridge, U.K., 2005.

8 Leonenko, Y.; Keith, D. W., *Reservoir engineering to accelerate the dissolution of CO₂ Stored in Aquifers*. *Environmental Science and Technology* 2008, 42, (8), 2742-2747.

9 40 CFR 144-146

10 40 CFR 146.10

11 Gerard, D.; Wilson, E. J., *Environmental bonds and the challenge of long-term carbon sequestration*. *Journal of Environmental Management In Press, Corrected Proof*.

extend the period of post closure care and well operators are required to file a plan, continue any cleanup and groundwater monitoring, and operators are required to retain information for three years after well closure.¹² For Class I hazardous waste wells the surface owner must also record the location of the well onto the property deed or “some other instrument which is normally examined during the title search” to alert future purchasers “in perpetuity” that 1) the land was used to manage hazardous waste; 2) the type of hazardous waste injected, the injection interval and dates injection occurred; and 3) with what agency the information was recorded.¹³ State requirements for other types of UIC permitted wells vary.

Adopting such an approach for large-scale sequestration of CO₂, however, is problematic for several reasons. First, such projects will involve much larger volumes of fluid than that injected in most other UIC regulated activities.¹⁴ Second, an adequate resolution of the issue of long-term stewardship will be essential in securing public acceptance of CCS projects. Third, if carbon credits associated with the injected CO₂ are being traded in a national or international emissions trading market, a mechanism must be available to verify that the sequestered CO₂ remains in the subsurface, sequestered from the atmosphere. Additionally, bonding works only for well understood risks over well defined time frames. The specific risks over the long-term and stewardship period are not yet well defined.

7.2 A Wholly Private-Sector Solution

In a wholly private-sector solution each project (or operator) would have to bear the full cost of the expected value of any future problems. Presumably this could be handled through the establishment of some form of internal company sinking fund that would assure the availability of resources should they become necessary or, alternatively, through purchase of third-party insurance (if it is available).

While there are appealing aspects of an approach to long-term stewardship that is totally private, the difficulty is that private sector entities often have relatively short time-horizons and lifetimes in comparison to the period over which injected CO₂ must remain sequestered.¹⁵ However, we have heard arguments by a few that some major well established firms (such as large multi-national oil companies, financial companies or insurance companies) might have enough stability, and a sufficiently balance sheet to finance and manage such long-term endeavors.

“... an adequate resolution of the issue of long-term stewardship will be essential in securing public acceptance of CCS projects.”

¹² 40 CFR 146.72

¹³ 40 CFR 146.72

¹⁴ Wilson, E. J.; Johnson, T. J.; Keith, D. W., Regulating the ultimate sink: managing the risks of geologic CO₂ storage. *Environmental Science and Technology* 2003, 37, 3476-3483.

¹⁵ Even long-lived firms such as the Hudson's Bay Company (established in 1670) have lifetimes short compared with many governments, and undergo dramatic changes in their mission and institutional arrangement over their lifetime.

“Experiences with company pension funds... or insurance companies that have gone bankrupt... raise doubts about the permanence or adequacy of a private sector solution.”

Experiences with company pension funds, the liability for which have been transferred to the government during bankruptcy proceedings,¹⁶ or insurance companies that have gone bankrupt after major disasters¹⁷ or because of risky investing,¹⁸ raise doubts about the permanence or adequacy of a private sector solution. As in all of these cases, government would have to intervene if serious problems were to arise at a sequestration site after the injecting parties cease to exist (see Section 7.5 below).

7.3 States Assume Responsibility For Sites Within Their Borders

In the interest of promoting CCS projects—both to advance the demonstration of the technology and to support their local industries—several U.S. States are already moving in the direction of developing legal frameworks in which the State would assume responsibility for long-term stewardship once a project is closed out. For example, Kansas established a trust fund to cover long term stewardship costs,¹⁹ to be financed by fees on CO₂ sequestration operations. Draft rules specify that after Kansas state regulators grant a site post closure status, any future costs will be assumed by the state using the trust fund.²⁰ Ohio and Michigan have introduced, but not yet passed, similar legislation.²¹

A state level solution avoids the concerns over the lifespan of a private entity, presuming that there are no threats to the integrity of the government. However, the financial model for state level responsibility should be based on a sinking fund with risk-based contributions rather than deficit financing, which will ensure funds are available if remediation is necessary.

An example of a flawed scheme for state liability is provided by the property and casualty insurance market in Florida.²² Many insurance companies concluded that the liabilities that they were assuming in coastal Florida were greater than they could manage given the limits on rates that the State was imposing in the interests of continued economic development. Accordingly, Florida set up its own insurance program, Citizens Property Insurance Corporation, allowing consumers to purchase an “affordable” policy from that program. In 2007 Citizens went from being an insurer of last resort to becoming the largest insurer against losses from wind in Florida. If Florida is hit by a catastrophic hurricane in the next few years it is very likely that Citizens will not have sufficient funds to cover its losses, in which case the State will have to assess policyholders in the State, issue bonds to cover the cost, or tax its citizens in some fashion. If the future disaster is large enough, the federal government will almost certainly be forced to intervene.

16 For a recent example, see Maynard, M., United air wins right to default on its pensions. *The New York Times* May 11, 2005.

17 For example, see Chiles Jr., L.M., Hurricane bill, insurance bailout pass on Legislature's final day. *St. Petersburg Times* December 12, 2008.

18 The recent bailout of AIG is a timely example.

19 HB 2419, enacted May 2007

20 draft K.A.R. 82-3-1117(d)

21 OH HB 487 (2008), and MI SB 707 (2007)

22 Robert Klein, Chapter 2 in Kunreuther and Michel-Kerjan, eds., *At War with the Weather*, MIT Press, 2009.

Even though it is difficult to envision the remedial costs associated with a sequestration project costing anywhere near as much as dealing with the aftermath of a major hurricane in Florida, the possibility of inadequate state funds is a real one and would tend to undermine public confidence in CCS efforts relying on this approach to stewardship. Moreover, the pool of projects over which risk can be spread may be very small in some states.

Certification that the injected CO₂ remains sequestered, away from the atmosphere, presents another hurdle for state-specific responsibility to overcome if CO₂ is traded on national or international markets. This issue is discussed further in Section 7.7.

There are two issues of institutional design that apply both to the creation of a state-by-state solution and a federal solution. These are discussed in Section 7.5.

7.4 Federal Responsibility for All Sites

Federal responsibility for long-term stewardship appears at this point to be the most viable oversight model. Such a model avoids the variability, limited resources and economic redundancies of state-financed oversight, the complications of interstate CO₂ plumes, and creates a consistent basis for emissions trading.

A federal model provides greater resources and enhanced risk-spreading than a state-by-state model. Any program of long-term stewardship should be self financing. That is, during the operation phase of a project, the injecting entity should be making payments into a sinking fund that will cover the costs of occasional monitoring and associated administrative costs of long-term stewardship. This pooled fund should also be sufficient to cover the cost of any low-probability, but potentially expensive remedial activity that may be required. If the low risk associated with sequestration can be spread across all projects in the nation, the costs for any single project could be significantly lower than if the risk is shared only by a small number of projects at the state level.

Additionally, if there is a default involving very large expenses under a long-term stewardship program being operated by a private entity or by a state, there is a high likelihood that the federal government would have to assume responsibility. A national sinking fund is better equipped to handle any contingencies that may arise, than a post hoc federal bailout. In the latter case, expenses would have to be covered by taxpayers rather than the original site operators, who may have dissolved as a legal entity.

“If the low risk associated with sequestration can be spread across all projects in the nation, the costs for any single project could be significantly lower than if the risk is shared only by a small number of projects...”

A federally administered program would also create a level regulatory playing field for injectors. Some CCS projects injecting into formations that lie below several different states may use pore space in more than one state. Requiring a project to adapt to different rules and procedures in different states, would complicate and increase the costs of CCS projects.

Federal oversight will also aid in the administration of emissions trading markets. It seems likely that any future CO₂ control regime at the federal level will allow emissions trading. While we think it unlikely that the U.S. will become a signatory to the Kyoto agreement, it does seem likely that at some stage in the future, the U.S. will enter into an international agreement limiting greenhouse gas emissions. Such an agreement will likely involve international trading of CO₂ emission allowances. While private firms may play a role in facilitating such a market, ultimately it will have to be national governments, not private parties or states (or provinces), that certify that international obligations are being met, and that sequestered CO₂ remains sequestered. Presumably, at least some entities that buy offsets associated with injected CO₂ will want to purchase insurance for the value of their offsets. Again, while private firms may play an important role in providing the needed certifications, national governments will have an oversight roll in assuring the efficient and honest operation of any such verification system.

7.5 Considerations for Institutional Design

We see two issues of institutional design that must be resolved to create either a federal (or state-based) system of long-term stewardship:

1. To avoid potential conflicts of interest, the government entity responsible for long-term stewardship should not be the same agency as is responsible for the regulatory oversight of the project during its operation. For example, if regulatory oversight during the operational phase of the project is the responsibility of the U.S. EPA (or a state operating under delegated authority), then some other entity should be responsible for long-term stewardship, and should have authority to only accept a closed site once criteria they have established have been met. This entity might be a new service within the Department of the Interior, a new independent agency, similar to the Federal Energy Regulatory Commission or the Federal Reserve, or a wholly owned Federal Government Corporation such as the Export-Import Bank of the United States.
2. A sinking fund should be created into which all operating projects pay a modest fee for each tonne of injected CO₂. Revenue from this fund should support all expenses of the entity responsible for long-term stewardship (i.e., monitoring of the injected CO₂ and remedial activities). The fund should be “raid-proof”—it should be established in such a way as to

make it impossible to use the accumulating capital for any purpose other than paying the costs of the long-term stewardship program. If a science-based mechanism can be found to identify the level of risk associated with the geology and design of specific projects, a portion of the payment could be made variable. In any event, because the cost of oversight, and the probability of needing significant remedial action during the period of long-term stewardship should both be low, this fee should not constitute a significant cost of site operation.

Elsewhere in this report, we have argued that before putting any definitive system in place for the regulation of CCS it will be important to develop experience with a number of large injection (i.e., 10 or more) projects. With that experience, it should be possible to develop a fee structure for the sinking fund for long-term stewardship. It is also likely that, as additional project experience is gained, the fee structure may need to be adjusted. To keep the costs for initial projects low, it may be desirable to create an initial obligation that can be reimbursed as funds accrue. We welcome advice on how best to design a fund to cover the costs of long-term stewardship in a way that makes it difficult for funds to be misappropriated, while also equitably distributing excess funds once a long track-record of safe stewardship has been established.

7.6 A Hybrid Private-Public Solution

While a federal model for long-term stewardship appears to be the most attractive option at this time, a variety of hybrid solutions involving a combination of public and private participants is also possible.

This model would exceed simple contracting to private firms to execute tasks such as monitoring or remediation. Rather, one could imagine a system in which, through competitive bids a private firm is given responsibility for all aspects of long-term stewardship, either on a state-by-state basis or for the nation as a whole. The state or federal government could establish operational guidelines, and establish regulatory oversight to assure that the private firm is protecting public health and the environment while also being fiscally sound. Government could require the firm to purchase insurance against the costs of remedial activities, but provide some cap on their financial responsibility, above which the government would assume responsibility. If such an approach were taken, we believe that it would still be important that the system be self-financing through some form of sinking fund.

“We welcome advice on how best to design a fund to cover the costs of long-term stewardship in a way that makes it difficult for funds to be misappropriated, while also equitably distributing excess funds...”

“... CCS site operators and traders will look to trade credits for offsets from sequestered CO₂.”

7.7 Certification for National and International CO₂ Emission Trading Markets

As noted above, almost any regulatory regime to limit CO₂ emission is likely to also entail some linkage to an emissions trading market. Indeed, such markets are already being developed or in operation, examples being:

- the North East Regional Greenhouse Gas Initiative;²³
- the voluntary Chicago Climate Exchange,²⁴ and the similar Montreal Climate Exchange;²⁵
- the EU ETS,²⁶ in which California has considered participating; and,
- numerous corporate trading programs, such as that established by BP.²⁷

Within an emissions trading market, CCS site operators and traders will look to trade credits for offsets from sequestered CO₂. Certifying that injection has taken place is presumably a reasonably straightforward matter and the IPCC has published accounting guidelines for use in developing national emissions inventories.²⁸ However, one tonne of CO₂ sequestered will not be equal to one tonne offset, for two reasons: first, the energy penalty of capturing and sequestering the CO₂ (see Section 2.1 for discussion), and second, the potential for CO₂ leakage back to the atmosphere after it is sequestered.²⁹

Discounting to account for the additional life-cycle emissions from additional coal use, energy consumption of the capture unit as well as compression for transport and injection will need to be based on the specific industrial configuration of each project. While complex, these types of calculations are similar to those made for offsets from other industrial processes under the EU ETS and the Clean Development Mechanism, and can be worked out for CCS in the development of national and international emission trading markets.

Accounting for potential leakage is less straightforward; approaches based on either a discount factor or site monitoring are possible. An *ex ante* mechanism would incorporate leakage into a discount factor, where an *ex post* method would require the party who holds the credits, or the party responsible for the site, to purchase emissions allowances from the market at the time of leakage. It is expected that leakage rates will be negligible for most sites, but the technical challenges of certifying this on a site-by-site basis are substantial.

²³ For details see <http://www.rggi.org/>

²⁴ For details see <http://www.chicagoclimatex.com/>

²⁵ For details see http://www.mcx.ca/index_en

²⁶ For details see http://www.europeanclimateexchange.com/default_flash.asp

²⁷ Victor, D. G.; House, J. C., BP's emissions trading system. *Energy Policy* 2006, 34, (15), 2100-2112.

²⁸ Holloway, S.; Karimjee, A.; Akai, M., et al., Carbon dioxide transport, injection and geological storage. In *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Eggleston, S.; Buendia, L.; Miwa, K.; Ngara, T.; Tanabe, K., Eds. IGES: Hayama, Japan, 2006.

²⁹ For discussion on the efficiency of CCS considering the energy penalty associated with capture, see Ha-Duong, M.; Keith, D. W., Carbon storage: the economic efficiency of storing CO₂ in leaky reservoirs. *Clean Technologies and Environmental Policy* 2003, 5, (3-4), 181-189. as well as as well as Teng, F.; Tondeur, D., Efficiency of carbon storage with leakage: physical and economical approaches. *Energy* 2007, 32, (4), 540-548.

Taking the *ex ante* approach, once a substantial amount of field experience has been gained it may be feasible to incorporate average observed leakage rates into a discount factor for CCS offsets.³⁰ Discounting based on average field performance, however, is disincentive for a site owner to design and operate a project designed to a higher standard and creates a moral hazard. Most operators are likely to want their credits to be based on the performance of their own field—and doing so may be in the public interest in as much as it provides incentive to site operators to design and operate their site so as to completely eliminate any slow long-term leakage. Thus, at least during site operations, it may be preferable to take the *ex post* approach, with the site owner managing his responsibility for potential leakage through some sort of insurance.

Once a project has been closed, markets will demand continued verification that offsets being traded remain valid—that is, that the sequestered CO₂ has not leaked back to the atmosphere. This issue is discussed further in Chapter 10. Verification of CO₂ containment in this context clearly overlaps the needs and responsibilities of whatever entity is responsible for long-term stewardship. Confidence that this entity can verify containment and meet any climate liability costs will be vital to successfully integrating CCS into a carbon market system.

“Once a project has been closed, markets will demand continued verification that offsets being traded remain valid.”

³⁰ For further discussion see Ha-Duong, M.; Keith, D. W., Carbon storage: the economic efficiency of storing CO₂ in leaky reservoirs. *Clean Technologies and Environmental Policy* 2003, 5, (3-4), 181-189. as well as Teng, F.; Tondeur, D., Efficiency of carbon storage with leakage: physical and economical approaches. *Energy* 2007, 32, (4), 540-548.

Chapter 8: The Elements and Goals of Liability During the CCS Project Life Cycle

The capital markets to which CCS projects will turn for financing abhor uncertainty. Similarly, both the public and elected officials seek assurance that an emerging, technology-rich approach to address the carbon challenge will not expose the public to undue harm, or impose harms for which there would be inadequate redress. For these reasons, a set of clear and equitable liability rules will be an essential component of any successful legal and regulatory framework for CCS. “Liability” in this context means a legally enforceable obligation to compensate (if not make whole) a person or entity that has suffered a discrete harm that they were otherwise entitled to avoid. Not every harm triggers liability. Indeed, while one might debate whether they always act with discretion, legislatures routinely define the harms that are legally cognizable and the extent to which they trigger legal obligations of those deemed responsible for the harms, exercising great discretion and limited only by the U.S. Constitution (and its state counterparts).

Liability rules can define and narrow uncertainty, but they cannot and should not eliminate it. Within reasonable bounds, markets compensate investors for incurring risks, and, just as with other commercial undertakings, their liability for such risks should operate as an incentive for the owners and operators of CCS projects to conduct their operations prudently in order to advance the interests of their investors. However, in the absence of an established set of liability rules, or with rules that do not reassure investors that risks can be known and quantified, investors may simply be unwilling to put their capital at risk in CCS projects.

This chapter is about liability in the geological sequestration (GS) phase of CCS. Liability issues that arise in connection with capture facilities (Chapter 2) will be similar to those that arise for any large industrial facility, such as a power plant or refinery. Liability issues involving CO₂ pipelines will be similar to those arising with natural gas pipelines (Chapter 3).

It is important to differentiate the issue of liability in terms of the different stages in an injection project’s life cycle. As indicated in Figure 8.1, issues of liability, and the strategies for addressing them, during the operational phases of a project are not likely to be dramatically different than those associated with any large industrial project, and can presumably be addressed by conventional strategies. It is only after a project enters the period of close-out and long-term stewardship that less conventional strategies for addressing liability will likely be needed.

“It is only after a project enters the period of close-out and long-term stewardship that less conventional strategies for addressing liability will likely be needed.”

In Section 8.1, we discuss the goals that should be addressed in designing a liability system for CCS. We lay out options along a “spectrum” of potential solutions and briefly describe some lessons drawn from historical experience with past liability schemes along that spectrum. Then in Section 8.2, we make this abstract discussion more concrete by discussing four legal frameworks that have been adopted to address risks in the past. Section 8.3 then walks through the project life cycle, discussing potential liability issues in each phase. Finally, in Section 8.4, we summarize our current thinking and seek readers’ advice and comments.

8.1 Goals of a Carbon Sequestration Liability Scheme

The design of an approach to liability should consider two complementary objectives: to ensure that those conducting sequestration operations conduct themselves in a responsible, prudent and accountable manner, while at the same time providing a level of predictability sufficient to encourage the large capital investments that will be required to make CCS projects a reality. These two objectives are not necessarily in “zero-sum” opposition to each other, but there certainly will be a tension between them at many times. In balancing the two concerns, one important element must be the perceived consequence of error in each direction. For example, a relatively high level of concern

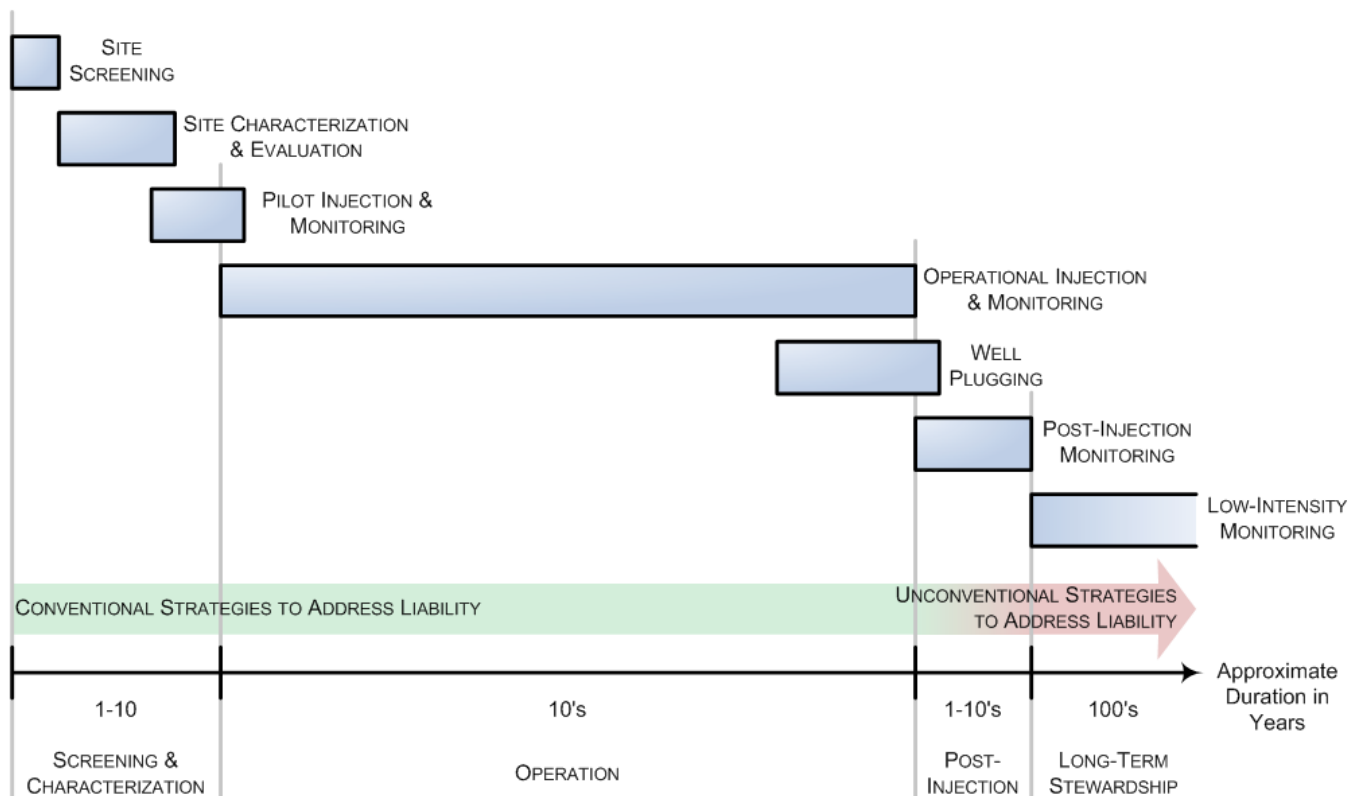


Figure 8.1: During the active phases of a CCS project, issues of liability, and the mechanisms for addressing them, are likely to be similar to those in any other large industrial project (e.g., insurance). However, once a project enters the post-injection phase, is closed, and enters long-term stewardship, less conventional strategies will likely be needed.

about carbon emissions reaching the atmosphere may lead to a desire to set relatively low liability risks for investments in CCS, while a relatively high-level of concern about the impact of CO₂ on drinking water or mineral resource acquisition may lead to a desire to set relatively high levels of liability for such harms. In both cases, though, a review of other liability schemes and policies may offer some useful insights for the design of future CCS obligations.

Liability exposure for a CCS project is likely to fall into one of three broad categories: tort, trespass, or contract. According to Black's Law Dictionary,¹ a tort is "a breach of a duty that the law imposes on persons who stand in a particular relation to another." In the context of CCS, a tort claim may arise when an activity conducted by the injection operation results in an injury to a third party. For example, if leakage from a sequestration site results in damage to a person or their property, the CCS operator may be liable for damages owed to the injured person.

Second, a CCS injection operation may be liable for a trespass, i.e., an unlawful act committed against a person or property of another, usually caused by the direct or indirect physical intrusion on private property. Trespass liability for a CCS operation may arise where a CO₂ leak results in damage to private property, such as private subsurface water or mineral rights.

Third, a CCS operation could face liability for damages resulting from a breach of a contractual obligation. Contractual liability could arise if leakage were sufficient to undermine the value of carbon credits associated with an injection operation (Chapter 9). If the entity that captures the CO₂ is different from the one that does the sequestration, liability could arise if a CCS project breaches its obligation to carbon producers that have relied on the project to maintain and store the carbon they have consigned to the project. This could be significant, for example, in terms of a contract for sequestration which is designed to fulfill obligations under a regulatory scheme that limits the allowable emissions of greenhouse gasses.

The balance of our discussion focuses on tort liability. We can view the strategies that are available to address potential tort liability as falling along a spectrum of approaches as shown in Figure 8.2. From the perspective of a project operator, these range from very severe potential liabilities (at the left end of Figure 8.2) to virtually non-existent liability (at the right end). As one moves along this spectrum from left to right, the tort liability exposure for a CCS injection operation decreases.

“Liability exposure for a CCS project is likely to fall into one of three broad categories: tort, trespass, or contract.”

¹ 8th edition, 2004

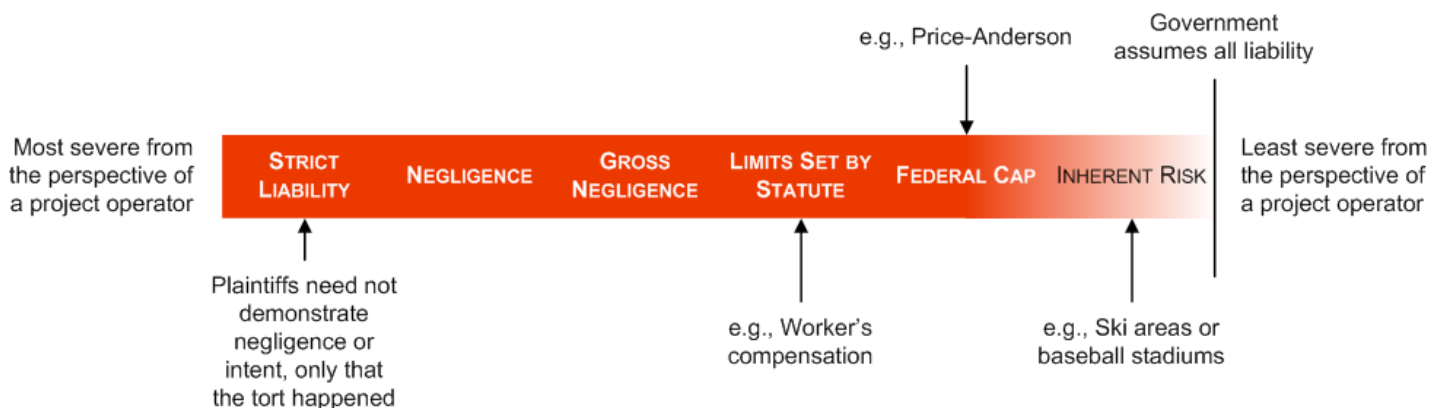


Figure 8.2: Spectrum of alternative strategies for addressing liability from the perspective of the project operator.

Strict liability, which does not require the injured party to demonstrate negligence or any intent to harm, lies at the leftmost end. Strict liability imposes an absolute duty to make something safe or to ensure that an undesired event does not happen; it has typically been imposed in the context of ultra-hazardous activities. Because CCS activities that operate under the sort of regulatory frameworks outlined in Chapter 6 will not, by any plausible definition, be ultra-hazardous, strict liability is not appropriate for CCS operations.

Moving to the right, under a simple negligence rule, an injured party must prove that the defendant owed a duty to the injured party, that the injury was suffered due to a breach of that duty, that the breach was a proximate cause of the injury, and that the plaintiff suffered actual harm. No showing of poor motive or aberrant activity is required in order to assess liability under such simple-negligence schemes. As a next step, applying a “gross negligence” standard reduces liability exposure further by requiring a showing that the defendant consciously or recklessly disregarded the duty to the injured party. At both the “negligence” and “gross negligence” points on the spectrum, defendants have several affirmative defenses² that they can raise to avoid or to limit liability. Examples are contributory negligence and comparative fault, an allegation that the claimed cause is too remote from the injury alleged (a concept commonly referred to as lack of “proximate cause”) and assumption of risk (the concept that the injured party accepted the risk of being injured and, thus, should not be compensated for resulting harm). A negligence and gross negligence criterion might be justified in the case of CCS operations.

² “Affirmative defenses” are those defenses as to which the accused party (the defendant) and not the plaintiff or claimant bear the burden of proof.

Moving further to the right along the spectrum, liability for a CCS injection operation can be decreased through another technique: limiting the amount of financial exposure.³ Note that this option does not change the standard of fault. Rather, it establishes an explicit tradeoff—damages limits in exchange for liability without fault. For example, workers’ compensation laws provide a specific schedule of damages for particular injuries (as opposed to allowing judges or juries to make the determination). Similarly (in a very different context), the Price-Anderson Act provides partial indemnification for the nuclear industry against liability claims arising from nuclear accidents. The Act adopts a no-fault approach, capping the nuclear industry’s liability at \$10 billion. If a nuclear accident results in claims exceeding the cap, the federal government covers the difference and the nuclear plant operators are not liable for the amount by which the injuries exceed \$10 billion. It is difficult for us to see how the damages from even the largest possible CCS accidental release or other event could approach anything like these levels. However, if it proves difficult to secure financing for CCS project, some form of liability cap might warrant consideration.

“if it proves difficult to secure financing for CCS ... some form of liability cap might warrant consideration.”

At right hand end of the spectrum, liability is completely eliminated for the project operator. With concepts such as the “inherent risk”⁴ approach, an injured party that participated in an activity is held to have assumed the risk of inherent dangers associated with an activity, such as by going skiing or attending a baseball game. Another option is complete indemnification by the government; from the perspective of the “actor” (the project operator) this shares the trait of precluding the operators’ risk of liability. Neither of these approaches to eliminating all potential tort liability for a CCS project operator seems to be a good idea, since they remove an important incentive to design and operate projects in a safe and prudent manner.

8.2 Existing Mechanisms as Potential Examples for Limiting and Allocating Liability

The possibilities for defining the boundaries of liability in the CCS context, and then allocating it, are limited only by the creativity of policymakers, operating within broad constitutional limits. However, they will not write on a blank slate. In a variety of contexts, not all of them related to environmental regulation, federal and state governments have carefully created sophisticated statutory schemes to balance (1) attracting capital to socially desired purposes (by limitations on investment risk) with (2) protecting society against poor

³ Inversely, the deterrent effect of liability can be increased by putting larger amounts of funds at risk for proven violations of any given standard. Examples include treble-damages set by statute for violations of anti-trust statutes and deterrence/punitive damages set by some juries in tort cases.

⁴ The concept of “inherent risk” is logically related to, but distinct from, the concept of “assumption of risk” referenced above. The latter applies in a negligence case in which the defendant assumes the burden of proving that the plaintiff should not recover damages because the plaintiff knowingly took on the risk of injury. “Inherent risk” is a legal rule to the effect that some activities are simply so obviously dangerous that anyone who undertakes them should ordinarily not recover damages from anyone if injured during the activity.

“... adoption of a RCRA-CERCLA approach to liability for CCS projects would dramatically impede, or even prevent, the adoption of deep sequestration of CO₂...”

performance (by using some risk of liability to incent careful operational behavior). Four examples in particular offer some useful conceptual and practical lessons here.

Strict Liability—The Example of the Resource Conservation and Recovery Act: The Federal Resource Conservation and Recovery Act (RCRA), enacted in 1976 and subsequently amended, now provides a comprehensive “cradle-to-grave” regulatory system for managing waste. An operation that is involved in the treatment, storage, or disposal of hazardous waste is required to obtain a permit from the EPA. RCRA imposes restrictions on the use of waste disposal facilities, creates design and performance standards for such facilities, requires owners and operators of such facilities to disclose operational information to the EPA, and provides for a scheme for enforcement. Four years later, in the wake of the Love Canal disaster,⁵ Congress also adopted the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), sometimes referred to as the “Superfund” law. CERCLA imposes joint and several liability for contamination caused by hazardous waste. This potential responsibility applies not only to the current owner of a facility but also the owner at the time of the disposal, the generators of any hazardous substances located on the site, and, in certain instances, transporters of waste to the site. “Joint and several liability” means that each of these parties is potentially liable for all of the damages caused by any site to which they contributed waste; even if the actual harmful substance originated with another party. The standard can, therefore, be viewed as the strictest of strict liability, but also a form of legal liability that can be avoided by compliance with the RCRA standards (and/or doing business only with similarly compliant participants in the waste disposal industry). Conceptually, this form of liability offers great protection to injured parties, while encouraging industrial actors to manage their waste streams with great care. In practice, however, it has led to extensive and lengthy litigation, with a slow rate of clean-up at waste sites caused, at least in part, by defendants’ fears that any concessions would lead to large liabilities. Over time a pattern of clean-ups based on industry-wide pooled surcharges for “Super Fund” type restoration work created more progress than had efforts to litigate strict liability.

The RCRA-CERCLA approach may be conceptually appealing as a mechanism for encouraging great care in sequestration and minimizing risk of releases. However, as noted above, we do not believe that any of the risks posed by CCS rise to the level of constituting an ultra-hazardous activity. Discussions we have held with a wide range of experts and potential CCS

⁵ The Love Canal incident involved the construction of a school and 100 homes that were built on a site that contained more than 80 buried chemicals, including known carcinogens. The chemical company that formerly owned the site acknowledged its conduct but the deed by which it transferred the land (to the local school district, for \$1) stated that the company would not be responsible for any injuries that might occur. Robert V. Percival et al., *Environmental Regulation* (5th ed., 2006) at 366.

operators have convinced us that the adoption of a RCRA-CERCLA approach to liability for CCS projects would dramatically impede, or even prevent, the adoption of deep sequestration of CO₂, and, thus result in continued large quantities of CO₂ emissions entering the atmosphere.

Limited, Performance-Based, and Pooled Liability—The Example of Workers’ Compensation: Pooled liability schemes “average out” the spikiness of individual liability awards and, thus, serve to hedge or insure the “break-the-company” risks that can make specific litigation so intense. On the other hand, they also have an unattractive aspect: if they break the link between bad corporate performance and higher liability risk, they can weaken the incentives for investors and managers to push for good operational performance. One way to balance these two elements lies in performance-based pooling of liability, where all parties in an industry contribute to a pooled compensation fund, but the relative proportions of their contributions are directly related to their past performance in regard to relevant standards. Workers’ compensation schemes are an example of such a structure.

In every state except Texas,⁶ the civil tort system as enforced by courts has been replaced in the context of workplace injuries by a statutorily required workers’ compensation system. As legal historian Lawrence M. Friedman has noted, prior to the advent of this system on a state-by-state basis, workplace injuries were governed by the so-called “fellow servant” doctrine, a judge-made principle to the effect that a worker could not recover damages from her or his employer in connection with harms caused by another employee.⁷

According to Friedman, the fellow servant doctrine and its close relative, the “assumption of risk” principle (whereby employees were simply deemed to have accepted the risk of workplace injury), had, by the advent of the 20th Century, ceased being useful. As the U.S. became fully industrialized, workplace injuries increased dramatically, judges and juries grew more sympathetic to workers and litigation-related uncertainty proliferated.⁸ By enacting workers’ compensation statutes, state legislatures therefore affected a grand bargain: employees gained the right to recover and employers replaced litigation risks with certainty.

The objective of certainty was particularly well-served by the system that developed. Compensation to employees was on a no-fault basis—i.e., with considerable easing of the procedural elements of proof of negligence—but the amount of the recovery was strictly limited according to pre-defined schedule

“Pooled liability schemes ‘average out’ the spikiness of individual liability awards and ... serve to hedge or insure the ‘break-the-company’ risks ...”

⁶ Benjamin Wolkinson and the Michigan State University Employment Law Group, *Employment Law: The Workplace Rights of Employees and Employers*, 2nd Ed., 321 (2008).

⁷ Lawrence M. Friedman, *A History of American Law* (2d. ed., 1985) at 301-02 and 683.

⁸ Id. at 481-87. According to Friedman, by the late 1800s the law of industrial accidents had grown “monstrously large.” Id. at 484.

“... it should be possible to obtain insurance that covers tort liability risks during the operational phase of a CCS project.”

of benefits.⁹ “The employee could get no less; but he [or she] could also get no more; no more jury trials; no more chance at an inflated recovery. For this, the employers were grateful,” Professor Friedman has noted.¹⁰

Employers typically comply with workers’ compensation laws by acquiring policies from insurance companies that specialize in this kind of coverage.¹¹ Some employers, including the U.S. government and many large corporations, self-insure against workplace liability.¹² In a dwindling number of states, employers are required to subscribe to state-funded insurance, but these types of schemes are seen as inefficient and too subject to bureaucratic delays even in uncontested claims.¹³

Discussions we have held with a major reinsurance company suggest that it should be possible to obtain insurance that covers tort liability risks during the operational phase of a CCS project. Should that prove not to be the case, then the workers’ compensation system may offer some useful lessons for the CCS context. Employer premiums for workers’ compensation coverage are typically a function of experience ratings (i.e., they increase depending on the number of previous claims, a proxy for workplace safety) and in some instances employers are relegated to an assigned risk pool when risks are deemed too great by private insurance markets. For CCS projects, experience ratings would create appropriate safety incentives. When the insurance market deems a project too risky to insure, policymakers could either accept the market’s implicit judgment that the project is too dangerous or opt to create the CCS equivalent of an assigned risk pool. The same grand compromise that was attractive to employers in the early years of the 20th Century—opening the gates wider to liability in exchange for fixed and limited recovery amounts—may well have outcome-determinative significance for investors deciding whether to move forward with CCS projects. To assure that individual claimants do not draw unlimited (or unreasonably large) amounts from available pooled funds, claims could be limited to those that can be calculated economically (e.g., diminution in the fair market value of assets, lost wages, or medical expenses, as opposed to claims for pain and suffering, emotional distress, and/or punitive damages).

Tiered and Limited Liability—The Examples of Price-Anderson and Similar Acts: The Price Anderson Act, originally adopted as a temporary measure in 1957, was designed to encourage investment in nuclear facilities (including but not limited to nuclear power facilities) despite their potential for triggering enormous liability for damages and what was (at the outset of the industry)

⁹ Jack B. Hood, et al., *Workers Compensation*, 27.

¹⁰ Friedman, *supra*, at 683.

¹¹ Jeffrey V. Nackley, *Primer on Workers’ Compensation*, 2nd Ed., 5, (1989).

¹² *Id.*, 6.

¹³ *Id.*

uncertainty about how facilities would perform. The Act achieved its primary objective—encouraging the first wave of investment in nuclear power plants—but, particularly since becoming permanent, has been criticized as overly protective of industry and inadequate in its protections for human health and safety.

The Act permits those incurring damages from nuclear accidents to recover in strict liability (i.e., without proving fault) and creates a three-tiered scheme for providing such compensation.¹⁴ The owners of nuclear reactors are required to (1) obtain the maximum private insurance available and (2) contribute a set dollar amount to a funding pool that is the next level of recourse for claimants.¹⁵ Finally, should these sources of compensation be exhausted, the Nuclear Regulatory Commission can petition Congress to appropriate funds that would provide compensation for the remainder of the damages.¹⁶ Under this model, risk is gradually transferred as private insurers become better equipped to analyze attendant risks and the industry grows large enough to cover those risks. Variations on the Price-Anderson theme adopted by Congress include the Trans-Alaska Pipeline Authorization Act (which waives limit on individual owner liability in cases of negligence) and the Oil Pollution Act (creating a trust fund in the wake of the *Exxon Valdez* incident).

“Price-Anderson achieved its objective of creating a viable nuclear power industry in the face of obstacles that might have prevented this development.”

Price-Anderson achieved its objective of creating a viable nuclear power industry in the face of obstacles that might have prevented this development. The first iteration of the Price-Anderson Act required nuclear power licensees to obtain \$60 million of private insurance coverage, the maximum commercially available at the time.¹⁷ The Act provided a further \$500 million of Federal indemnification,¹⁸ for a total compensation package capped at \$560 million.¹⁹ The Act provided no compensation for damages beyond this limit.²⁰ Thus, in a \$1 billion accident, private insurance policies would have covered 6% of damages, the federal government would have absorbed a 50% share and the remaining 44% would have remained uncompensated. Nuclear power generation surged in the wake of Price-Anderson’s enactment. In 1957, there was only one, 60-megawatt reactor online. By 1966, 20 reactors were on order with a total capacity of over 16,000 megawatts.²¹

Subsequent amendments had the effect of shifting somewhat more liability to industry, but still avoiding unlimited exposure. In 1975, Congress created a retrospective funding pool to supplement private insurance.²² Such a pool would have been created only in the event of an accident, funded equally by all facilities covered by the statute.²³ Pool contributions were initially set at

¹⁴ 42 U.S.C. § 2210.

¹⁵ *Id.*

¹⁶ *Id.*

¹⁷ Pub. L. No. 85-256, § 4, 71 Stat. 576, 576-577 (1957).

¹⁸ *Id.*

¹⁹ *Id.*

²⁰ *Id.*

²¹ Dan Berkowitz, Price Anderson Act: Model Compensation Legislation? The Sixty-Three Million Dollar Question, 13 Harv. Envtl. L. Rev. 1, 11.

²² Pub. L. No. 94-197, § 6, 89 Stat. 1111, 1111-15 (1975) (codified as amended at 42 U.S.C. § 2210(e) (1982)).

²³ *Id.*

“While it seems unlikely that a CCS accident or other event could result in damages that approach the levels contemplated by the Price-Anderson Act, a similar model with more modest thresholds could encourage rapid development of the CCS industry...”

\$5 million per reactor.²⁴ The pool was designed to grow with the industry. As each new reactor came online, the federal government’s liability decreased by \$5 million. The 1975 amendments also altered the overall payout cap. The new cap was set at either \$560 million, or the sum of the maximum available amount of private insurance and the funding pool, whichever was greater.²⁵

Since the 1975 amendments, Price-Anderson has been amended twice, in each instance increasing the requirement for private insurance and raising the cap of individual reactor liability. Currently, each licensee is obligated to obtain \$300 million in private insurance and provide for an additional \$95.8 million in the event of an accident. This secondary pool totals about \$8.6 billion from 104 contributing plants for a total pool of over \$10 billion.²⁶ “After 15 percent of this pool is expended, prioritization of the remaining funds is left to the discretion of local jurisdictions. After the insurance pool is exhausted, state and local governments can petition Congress for additional disaster relief under the provisions of Price-Anderson.”²⁷ The fund is not created unless an accident occurs and payouts by licensees are limited to \$15 million per year until damages are paid in full or licensees reach their individual caps of \$95.8 million.²⁸

While it seems unlikely that a CCS accident or other event could result in damages that approach the levels contemplated by the Price-Anderson Act, a similar model with more modest thresholds could encourage rapid development of the CCS industry by limiting the liability uncertainties inherent in a nascent technology. With the limits set at plausible levels, the remaining investor-risk could create an incentive for good performance. On the other hand, the limitations on liability create a risk that either the general public or taxpayers will have to cover part of the cost of adverse events if they occur at a level higher than the limit on operator liability. Conceptually, the answer to this is relatively straightforward—the risk of uncompensated public harm because of a liability limit should be weighed against the risk of uncompensated public harm if carbon dioxide emissions that could have been sequestered are, instead, vented into the atmosphere. However, quantifying and monetizing that weighing will require careful analysis and, ultimately, some judgment-call decision-making in the face of imperfect information and pressing time limits.

Prohibitions on Liability—The Examples of Skiers and Baseball Spectators:

In some cases, legislatures and courts have simply ruled that there can be no compensation for injuries suffered from some activities. For example, at least

²⁴ *Id.*

²⁵ *Id.*

²⁶ United States Nuclear Regulatory Commission, Nuclear Insurance And Disaster Relief Funds Fact Sheet (2008), [hereinafter USNRC FACT SHEET], available at <http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/funds-fs.html>.

²⁷ *Id.*

²⁸ *Id.*

in some states, users of certain recreational facilities—e.g., skiers at a ski area or spectators at a baseball game—are simply precluded from recovering damages from the owners of the facilities for harms that are foreseeable results of the activities in question. Courts in some states have concluded that skiing is so clearly a dangerous activity, and the mitigation of perils so difficult an undertaking for ski area owners, that it would be unreasonable to allow victims of ski injuries to pursue negligence cases against ski areas. In the baseball context, projectiles of various sorts flying off the playing field are deemed to be such an ordinary byproduct of the game that, in essence, no one connected with the game or its facilities has a duty to avoid causing game-related harms. Such public policy is sometimes premised on the notion that users acknowledge and then assume the “inherent risk” of the activity and any owner negligence associated with it. However, it is also clear that the protections against liability inherent in such policies are closely linked to beliefs that the shielded activities are socially desirable, at least as sources of revenue for local economies and state government.

In the context of CCS, this approach would have simplicity to recommend it—and, of course, it could promote investment in CCS facilities by eliminating nearly all liability risk. However, it also carries obvious negative aspects. For example, injured skiers and/or spectators are voluntarily undertaking activities that are nonessential. Thus, they are not analogous to individuals who are involuntarily exposed to harms arising out CO₂ sequestration that has been undertaken and authorized in furtherance of the greater good. This kind of public policy is vulnerable to the argument that too much of the burden of negligence-related harm is allocated to those with the misfortune to suffer such injury, as distinct from the public at large which benefits. Moreover, this liability paradigm lacks incentives for CCS projects to avoid acting in a negligent manner. Thus, it may be particularly troubling as a model for liability in the period when operator competence is particularly significant and may be less troubling (but still of concern) when operational responsibility has been transferred to the sovereign government. Our current thinking is that such a model would not be appropriate for any phase of CCS project activity.

Citizen Suits as a Public Confidence Builder: As a means of instilling public confidence that regulations are being followed and to assure the accountability of potentially controversial private sector projects, such as CCS facilities, citizen suit provisions have the potential to be an effective mechanism. Note that the phrase “citizen suits,” does not denote an individual person pursuing a tort claim but rather the standing of an individual citizen to enforce regulations in the same manner that a regulatory agency like EPA would. A discussion of this option is provided in Chapter 6.

“During injection operations, the project entity should remain primarily responsible for injuries to people or property that are traceable to the project’s injection activities ... site operators should be able to secure private insurance to cover potential liability during this stage of a project...”

8.3 Liability for the Life Cycle of a Geologic Sequestration Project

In considering potential liability regimes, it is important to bear in mind that the technological and economic realities are not the same at each stage along the project life cycle (Figure 8.1). In the early phases of a project (i.e., during the project development and injection phases), risks will generally be better known. Therefore, there is much less reason to deviate in these phases from traditional legal approaches to negligence. However, later life cycle phases will likely require more creative liability strategies to achieve our goal of ensuring long-term accountability while offering the necessary predictability to encourage investment.

Site Screening, Characterization, and Evaluation: During these phases of a CCS project, developers will need to perform adequate due diligence to ensure that the proposed site is appropriate for a large-scale injection operation. Issues of liability during site screening, characterization, and evaluation are likely to arise, if at all, in the context of intra-ownership disputes over representations to investors about project feasibility. There are also issues relating to representations to government agencies in the permitting process. In these contexts, traditional liability principles leave the incentives where they arguably should be, with developers and their experts left with enough liability-risk to incent them to be thorough and candid in their representations both publicly and within their corporate deliberations.

Injection and Operation: The second phase of a geologic sequestration project begins when the project entity has received the appropriate permits from various regulatory bodies. During injection operations, the project entity should remain primarily responsible for injuries to people or property that are traceable to the project’s injection activities. A major component of operational responsibility that should remain with the project entity involves the ongoing monitoring and verification necessary to ensure that the sequestered CO₂ behaves as predicted. In addition, the project entity should be responsible for ensuring site performance, possibly through a performance-based pooled fund, to address issues related to leakage and mediation measures to cure leakage problems.

Numerous liability issues have the potential to arise during the operational phase of the life cycle. An injection project will need to ensure that it operates in a reasonably prudent manner, and the liability scheme should be structured to encourage this compliance. On the basis of discussions we have had with the industry, we believe that site operators should be able to secure private insurance to cover potential liability during this stage of a project, and that securing adequate insurance for this purpose should be a precondition for regulatory approval.

If, after a first round of large commercial projects, it becomes clear that private insurance will prove difficult or impossible to get, then two strategies might be pursued to rectify the situation. Legislation could be passed to implement some form of damage cap or a performance-based pooled fund could be created, designed in such a way as to encourage a high standard of operational performance.

Another area where liability is an issue during injection operations relates to breach of contract claims that could arise in the context of a CO₂ trading system. This type of liability is likely to arise when an injection project sells credits produced from an operation that fails to adequately retain sequestered CO₂. Contracts to sell CO₂ credits should reflect reality, and acknowledge the possibility of leakage through mechanisms discussed in Chapter 9. In addition, third party verification, similar to how Renewable Energy Credits (RECs) are verified under state-law renewable portfolio standards for utilities, could add a level of transparency to credits generated from sequestration projects to provide assurance to credit traders.

Post-Injection and Site Closure: Upon completing injection operations, the life cycle moves to the post-injection and site closure phase. During this phase, the project entity should take the necessary steps to ensure that injection wells not used for monitoring are permanently plugged, continue monitoring for leakage and, potentially, track migration of the injected CO₂.

As discussed in Chapters 4 and 7, conceptual models of GS suggest that leakage has the highest chance of occurring as injection ends and the beginning of the post-injection phase. The project entity should remain liable for releases that result in injuries to people and property during this phase. The project entity should be liable for failing to adequately monitor the site and for failing to mitigate releases.

Long-Term Stewardship: At some time after injection operations cease and the site has been closed, many have argued that the project entity should have the option to transfer legal responsibility, along with tasks associated with long-term monitoring and mitigation (which are discussed in Chapter 7), to government entity. If legal responsibility is transferred to a third party, regulatory mechanisms will need to be developed to ensure that the transfer and subsequent release from liability can occur smoothly. A project entity that fails to comply with these regulatory standards should remain liable until it satisfies the necessary requirements.

As discussed in Chapter 6, a sinking fund that is paid into during the operational phase could cover the costs for long-term monitoring and leakage

mitigation needs. In the model in which all liability is transferred to a third party (i.e., the government), this fund could also cover compensation for the cost of any damages. However, where a claim arises that predates the transfer, the project entity should be liable for damages arising from that claim.

Liability for Trespass: Apart from damages arising out of negligence, or contractual disputes related to the issuance of carbon credits for sequestered CO₂, a CCS project faces the prospect of liability for trespass, a legal theory that redresses property owners for physical invasions of their property by others and/or activities by others that substantially limit their ability to use and enjoy their property fully. As a practical matter, this type of potential liability is best considered in the context of the takings principle discussed in Chapter 5. In other words, if the government fully and appropriately defines the property rights that are or are likely to be affected by CCS projects, and then compensates the owners of those rights in a constitutionally sufficient manner, risks to project developers for liability in trespass are effectively eliminated. If necessary, any residual liability may be appropriately allocated to government.

8.4 Conclusion: Possible Policy Directions

Although CCS has much in common with certain existing industries and technologies, policymakers must use caution as they consider how regulatory and liability schemes applicable in those other contexts will function in what is today uncharted territory. Other commentators have already warned against simplistic approaches. For example, a September 2008 article in *Daily Environment Report*, by Chiara Trabucchi and Lindene Patton,²⁹ issued warnings to policymakers developing liability schemes for application in the CCS context. First, they noted that existing federal risk management models like Price-Anderson confront only the question of compensation for damages—they do not address how to bear long-term carrying costs of the facilities themselves, particularly during the post-injection phases. Secondly, Trabucchi and Patton express the concern that a federal indemnification system “inappropriately may shift the burden of future liabilities to the insurance sector or other third-party institution in the near-term, and the general public in the long term.” In the interest of promoting projects of high quality and low risk, they call for a liability scheme that sends price signals to developers that appropriately reflect risk—and generally provide incentives for developers and policymakers to make decisions, particularly in the near-term, that are efficient and environmentally sound, especially in the long-term. That balancing will require both consideration of releases caused by poorly managed sequestration activities and of releases caused by uncontrolled emissions caused by lack of investment in CCS activities.

29 Patton, Lindene S.; Trabucchi, C., Storing Carbon: Options for Liability Risk Management, Financial Responsibility. *Daily Environment Report*, 170, September 3, 2008.

In pursuit of such a legal framework, we offer some preliminary insights that are derived from the research and analysis conducted to date. We offer them here in the hope that they will stimulate discussion and in the expectation that they will change as the discussion evolves.

- 1) During site screening, characterization and evaluation, it is probably appropriate to hold project operators to the same high standards as any other major industrial project in order to ensure the feasibility of the proposed project. Consistent with this approach, consideration should be given to holding a project that begins operation without the necessary permits strictly liable for failing to comply with regulatory requirements.
- 2) During site operations conducted in compliance with regulatory approval, either a standard of negligence or gross negligence should probably apply to any tort liability. To guard against “fly-by-night” operators who might disappear if problems develop, projects should be required to demonstrate that they have obtained appropriate insurance (or posted an appropriate bond) to cover plausible contingencies, as a condition for regulatory approval. If it becomes difficult or impossible to secure conventional commercial insurance to protect against such contingencies, then to assure that insurance coverage is forthcoming it may be necessary to limit the liability of a project operator to a predetermined amount during the period of injection operations. As a condition to permitting in such circumstances, the entity should be required to demonstrate adequate capitalization or insurance coverage to meet the statutory cap during the permitting process. Alternatively, as outlined in Section 8.2, payments by project operators into a performance-based pooled fund during injection operations might be an effective means to ensure the availability of reasonable compensation for injuries to people or property—as well as to mitigate any site retention problems associated with leakage.³⁰ However, at this stage, our preference is for private insurance-based solutions.
- 3) As discussed and elaborated in Chapter 7, it seems advisable that during injection a project entity should be required to pay into a (perhaps pooled state or Federal) sinking fund to cover the costs of site monitoring, mitigation, and any resulting damages during long-term stewardship. This would have the salutary effect of not imposing on future generations the obligation, in effect, to police the effectiveness of the current generation’s carbon sequestration program.

³⁰ In case such an option became necessary, it might also be appropriate to impose an enhanced penalty, such as some multiple of damages, on operators that have a record of repeated poor performance in their injection operations or have clearly violated the regulatory approval under which they have been operating.

“...the structure of liability policies for CCS activities can profoundly affect the pace and the quality of future CCS activities.”

- 4) During post-injection and site closure, it is reasonable for a project entity to remain liable for releases that harm persons or property—and for the project entity to remain responsible for continued monitoring of the injection site until a transfer to the long-term steward occurs. Failing to monitor the site adequately during this phase would expose the project entity to liability. As with the injection phase, the applicable risks are relatively predictable and manageable.
- 5) When a project entity satisfies site closure criteria and a third party or government entity assumes responsibility for the site, it may be appropriate to release the project entity from further liability. Such a release would not apply to claims that arose prior to transferring responsibility to a long-term steward. While this approach to long-term liability may generate criticism as a mechanism for absolving developers from long-term harms they cause, it reflects a policy judgment that ultimately the long-term benefits of CCS inure to the community at large in a manner that makes it appropriate to socialize the long-term risks in similar fashion, while also eliminating a formidable barrier to private investment in such projects.
- 6) During injection operations, an unresolved liability issue that must be addressed is what effect CO₂ leakage will have if the project entity issues tradable credits for sequestered CO₂, and how to minimize this risk. This issue is further discussed in Chapter 9.

In summary, we believe that the structure of liability policies for CCS activities can profoundly affect the pace and the quality of future CCS activities. The design of those standards should reflect a conscious effort to balance the dual goals of rapid development of the industry and strong desire for long-term quality in design, investment and operational performance. If such a balance is not struck through legislation that establishes a general regulatory framework for CCS, the issues will be resolved through individual suits in the courts, and may not achieve optimal balance of social objectives.

We invite comment upon—and additions to—the examples we have set out above, as well as critiques of the initial insights and tentative conclusion we draw from this analysis.

Chapter 9: Commercial Considerations

Regulatory policies will be a significant factor in determining the success or failure of commercial operations of electric power generation facilities with CCS technology. Decisions as to what to build, when to build, and how to operate a plant with CCS will be based on existing and expected regulation and other public policies. Regulations will determine the availability of funds for capital investment, the viability of the market, and the cost of operations. Regulatory and other policies will define the allowable financial risk-mitigation opportunities (e.g., tax and depreciation schedules, loan guarantees, bonds, and long-term Federal stewardship). At the same time, new regulations, rules, and incentives affecting the construction, operations, and retirement of CCS infrastructure must account for how these facilities will be operated and anticipate the dynamic effects that they will have on multiple markets and investment decisions. Without appreciating how an owner will likely operate a plant within the regulatory framework, there is a the potential for unintended consequences that cause more harm than good.

Section 9.1 outlines some of the hurdles that regulatory policy can help lower or eliminate to make commercial operations feasible. Section 9.2 explores possible policies to mitigate or distribute these risks. Section 9.3 discusses how allowing flexibility in operation of the CCS equipment could make the commercial viability of such plants more palatable to investors and operators.

9.1 Need for Policies and Regulations to Reduce Risk

Fundamental roadblocks to near- and long-term sequestration commitments include the lack of any regulatory requirement to control emissions, geologic uncertainties, regulatory uncertainties, liability issues, geologic rights issues, and commercial financing requirements. While these are discussed in detail elsewhere in the report, they are summarized here to set-up the discussion of commercial considerations.

Absence of a Requirement to Control Emissions or a Method for Valuing Their Reduction: While control on emissions of CO₂ will likely be imposed in the future, at the moment there is no such control. In the absence of a subsidy, tax policy, or similar incentive, any private effort to capture and sequester CO₂ is an added cost to a commercial undertaking. Tied to this is the likelihood of CO₂ market and the associated uncertainties that are inherent with such a market.

“The absence of a regulatory program makes it unclear how commercial projects could proceed.”

Geologic Uncertainty: The dominant uncertainty regarding commercial-scale sequestration is whether specific geologic formations targeted for injection will readily accept and successfully trap CO₂. Limited information is available about potential geological formations and significant seismic surveys, core sampling, and other assessments are needed before the likely capacity and suitability of a formation can be evaluated (see Section 4.1). Even with such information, the injectivity and mobility of CO₂ in a formation will remain uncertain. Until appropriate data collection and tests are completed, including actual CO₂ injection at commercial scale, not enough will be known for developers to assess accurately the feasibility, costs, and risks of large-scale sequestration. These uncertainties preclude responsible developers from making meaningful early commitments to sequestration.

Regulatory Uncertainty: Currently, no regulatory program exists that is specifically designed to govern large-scale injection of CO₂. While initial projects can be undertaken under the existing UIC program with a Class V permit, without a regulatory structure, it is unclear what permits and approvals will be needed to begin future large-scale CO₂ commercial injection or what safety guidelines, monitoring protocols, or verification procedures will be required. The absence of a regulatory program makes it unclear how commercial projects could proceed. This substantially increases the risk and uncertainty associated with undertaking a project because there are no guidelines by which to assess whether it is being done responsibly.

Liability Issues: An important issue that looms over developers wanting to pursue sequestration is potential liability, especially once a project has closed out and entered long-term stewardship. While it is unlikely that any CO₂ leak would be large enough to cause a safety hazard, it is still a risk (see Section 4.2). More likely is the possibility that small amounts of CO₂ may leak slowly, exposing operators to liability for not producing contracted reductions. Since CO₂ needs to remain sequestered permanently for a credit to be valid, potential liabilities for leakage will remain indefinitely unless a system is in place to limit or transfer that liability.

Rights to Use Pore Space: Another uncertainty with sequestration is determining how to secure the rights to use a geologic formation for the purposes of sequestration. In many places, it is currently unclear who—if anyone—has such a property right (see Chapter 5 for discussion). If it is unclear who owns the rights to a targeted geologic formation, it is not readily apparent how a project should go about acquiring those rights to

begin sequestration.¹ Resolution of this issue must precede any sequestration commitment.

Financing: The combined effect of sequestration uncertainties is that they render commitments to sequester open-ended economic exposures that today are likely impossible to finance. Gasification projects capable of capturing CO₂ at low cost are capital intensive and use advanced technologies (see Section 2.1). They require substantial equity and debt commitments and require careful financial structuring (and potentially state or Federal incentives or credit assistance) to attract capital. Projects that commit to unquantifiable sequestration cost risks will simply not be financeable. Until enough is learned about geologic realities, regulatory requirements, and liabilities large-scale sequestration commitments cannot be made by billion dollar projects needing commercial financing.

9.2 Opportunities to Mitigate the Financial Risks

An electric power generation plant with CCS capability is an integrated system that includes a variety of technologies each with their own risks and risk-mitigation opportunities. Solutions that would reduce risks for CO₂ pipeline construction may not directly impact concerns over geologic formation ownership. Discussed below are nine opportunities affecting one or more of the components in a CCS system.

As with any set of rules or regulatory framework that impacts markets and financial decisions, it is important to be mindful of unintended consequences that could lead to suboptimal outcomes. When trying to incentivize CO₂ sequestration from power plants, rules and regulations must be written so that perverse actions—such as creating CO₂-generation plants with the sole goal of profiting from sequestration—are prevented. The inclusion of performance standards would limit such behavior.

A Federal sequestration tax credit and investment tax credit for CO₂ pipelines: Currently, 15% of the costs incurred in enhanced oil recovery are eligible for the enhanced oil recovery Federal tax credit (claimed on IRS Form 8830). The Energy Tax Incentives Act of 2005 provides a 30% business investment credit for solar energy and fuel cell property and certain solar lighting systems; a 10% investment tax credit is provided for microturbines (claimed on IRS Form 3468). A tax credit in the range of 10% to 30% of incurred costs for carbon dioxide pipelines would be in accord with the Federal tax credits used to encourage the above investments.

“The combined effect of sequestration uncertainties is that they render commitments to sequester open-ended economic exposures that today are likely impossible to finance.”

¹ Keith, D. W.; Giardina, J. A.; Morgan, M. G.; Wilson E. J., “Regulating the underground injection of CO₂,” *Environmental Science & Technology* 2005, 39, 499A-505A.

A sequestration tax credit for geologic sequestration is likely to provide an effective incentive for sequestration projects. Such a sequestration tax credit should have provisions that reduce the tax credit if the U.S. enacts legislation resulting in a carbon price above the effective price established by the tax credit. Like the production tax credit, the sequestration tax credit may be designed with time limits both for the date by which the projects must be underway and the conclusion date of the tax credit.

The sequestration tax credit might also be designed with a limit to the total available, with projects competing on the basis of cost or on the basis of first come, first served. However, such a provision would introduce uncertainty that may inhibit investment.

We note that a per kilowatt-hour production tax credit, the Renewable Electricity Production Credit (REPC), is currently applied to electricity generated from low-carbon “qualified energy resources” at a “qualified facility.”² Enacted as part of the Energy Policy Act of 1992, the credit expired at the end of 2001, and was subsequently extended in March 2002 as part of the Job Creation and Worker Assistance Act of 2002.³ The tax credit then expired at the end of 2003 and was not renewed until October 4, 2004, as part of H.R. 1308, the Working Families Tax Relief Act of 2004, which extended the credit through December 31, 2005. The Energy Policy Act of 2005⁴ modified the credit and extended it through December 31, 2007. In December 2006, Section 207 of the Tax Relief and Health Care Act of 2006⁵ extended the tax credit for another year, through December 31, 2008. The recent Wall Street crisis and the \$700 billion “rescue” bill by the federal government included a renewal of the tax credits.

Section 710 of the American Jobs Creation Act of 2004⁶ expanded REPC to include, among other additional eligible resources, refined coal. Refined coal is defined as “a liquid, gaseous, or synthetic fuel produced from coal (including lignite) or high carbon fly ash, including such fuel used as a feedstock.”⁷ In addition, refined coal is considered a “qualified emission reduction” under the REPC if reductions of at least 20% of the SO₂, and either NO_x or mercury emissions are achieved through burning refined coal, as compared to burning the feedstock coal.⁸ The Energy Policy Act of 2005 further expanded the credit to certain hydropower facilities and Indian coal. Indian coal is coal produced from reserves which, on June 14, 2005, were either owned by an Indian

2 26 U.S.C. §45(a).

3 H.R. 3090.

4 H.R. 6.

5 H.R. 6111.

6 H.R. 4520.

7 26 U.S.C. §45(c)(7)(A)(i).

8 26 U.S.C. §45(c)(7)(A)(iii) & §45(c)(7)(B).

tribe, or were held in trust by the U.S. for the benefit of an Indian tribe or its members.⁹

Given that the current iteration of the REPC already creates set-asides for two specific coal resources, it would be reasonable to expand the scope of REPC to include coal-fired power plants equipped with CCS as a low-carbon “qualified facility” or a “qualified emission reduction” rather than enact new legislation for a sequestration-specific production tax credit. Including sequestration activities under an already-existing production credit provision of the tax code would decrease the amount of risk associated with learning and uncertainty that typically accompanies the application of economic incentives for new projects.

Advocates of the REPC have cited carbon dioxide control as a motivation, along with reduction of SO₂, NO_x, and mercury. Current prices for SO₂ and NO_x allowances and estimated prices for Hg control sum to 0.9 cent per kWh for an average coal-fired power plant in the current fleet. The REPC provides a tax credit of 1.5 cents per kWh, adjusted annually for inflation, for the sale of electricity produced from qualified energy resources at a qualified facility.¹⁰ Currently, the REPC for these technologies is 1.9 cents per kWh.¹¹ Using the average U.S. electric power industry CO₂ emission rate of 0.62 tonnes per MWh,¹² the present federal production tax credit equates to \$16 per tonne of avoided CO₂, when credits for avoided SO₂, NO_x, and mercury emissions are accounted for.

While tax credits offer an important policy lever to jump start the CCS industry, because a typical commercial CCS project will cost over a billion dollars, it is equally important that these credits have stability over time. A situation in which they cycle on and off from year-to-year in the face of Congressional legislative vagaries will not induce the large investments that will be needed for CCS on a commercial scale.

Pipelines may be financed by tax exempt bonds: Because of market uncertainty, there may be a need to provide some risk reduction for investors in CO₂ pipelines. This is despite the relatively low technical risk associated with pipeline design, construction, and operation.

Tax-exempt financing can be used by private entities under what are called Private Activity Bonds. Qualified Private Activity Bonds are tax-exempt bonds issued by a state or local government, the proceeds of which are used

“Using the average U.S. electric power industry CO₂ emission rate ... the present federal [renewable energy] production tax credit equates to \$16 per tonne of avoided CO₂ ...”

⁹ 26 U.S.C. §45(c)(9).

¹⁰ Internal Revenue Service Form 8835, “Renewable Electricity Production Credit,” p.2.

¹¹ Internal Revenue Service Form 8835, “Renewable Electricity Production Credit,” p.2.

¹² U.S. Energy Information Administration Electric Power Annual 2006 (with data from 2005).

for a defined qualified purpose by an entity other than the government issuing the bonds. Private Activity Bonds can reduce financing costs through lower borrowing rates because the interest paid to bondholders is not includable in their gross income for federal income tax purposes.

Financing with tax-exempt bonds requires strict compliance with a series of requirements and limitations established by the Internal Revenue Code. Many types of projects that are eligible for tax-exempt financing are subject to a federally-required annual volume cap, which restricts the amount of tax-exempt Private Activity Bonds that can be sold in any one state. Starting with 2007, the volume cap each state receives equals \$85 per capita per year.

There are two ways tax-exempt financing could be made available for CO₂ sequestration infrastructure investments, which could be defined to include investments in compression, pipelines, and sequestration facilities. One is for the IRS code to be amended to identify specifically CO₂ sequestration investments as “Qualified Private Activity Bonds.” Qualifying the investments would enable Private Activity Bonds to be issued under existing IRS rules and would be subject to state volume-cap allocations. Alternatively, legislation could be passed to create a separate allocation of Private Activity Bond authority for CO₂ sequestration investments. This type of legislation was passed to provide GOZONE bonds for states affected by Hurricane Katrina and for the Liberty Zone around ground zero in New York City. Since demand for tax-exempt bonds often exceeds volume-cap restrictions, it is probably preferable to create a separate allocation and program for CO₂ sequestration investments in this manner.

To create a separate bond allocation for CO₂ sequestration investments, federal legislation would be needed similar to the GOZONE legislation. A national cap on the amount available (say \$20 billion) would be established and bonding authorities from states with potential projects could apply for volume-cap distributions under the program. One complication that the program would need to overcome is that Private Activity Bonds must be issued by local government entities, making it somewhat unclear how such bonds might be issued for pipelines that might traverse several counties or states.

Direct Federal Payments per Tonne of Sequestered CO₂: The Department of Energy has undertaken a number of Regional Carbon Sequestration Partnerships¹³ to inject CO₂. Some of these, like the Midwest partnership in the Illinois basin, have begun EOR injections as the second phase of the regional partnerships. Phase III regional partnerships have recently had their schedule advanced and the project sizes enlarged. Total Phase III injections will be

13 See <http://www.fossil.energy.gov/sequestration/partnerships/index.html>

approximately 21 Mt (7 projects, each of 1 Mt per year for 3 years).

It is possible that some of the commercial gasification projects currently in advanced planning may be suitable for these Phase III projects (although most of the Phase III projects have already identified their CO₂ sources). The CO₂ stream from a single commercial gasification project represents at least three times the amount of CO₂ envisioned for any of the phase III sites. There may not be a match in the timeframe of planned commercial gasification facilities with the newly-advanced timetable for the Phase III regional partnerships. The limited time (3 years) of the Phase III projects is unlikely to be attractive to investors.

A better match would be a program encompassing a small but significant number of commercial-scale plants (around 10), with direct or indirect payments to each for sequestration. Such a program would rapidly advance commercial-scale experience. CCS projects currently being planned are said by developers to be able to transport and sequester at \$20 - \$60 million per plant, so the total costs would be in the range of \$200 - \$600 million annually (the current tax expenditures to support the wind portion of the federal production tax credit are approximately \$600 million per year). Further analysis may refine these cost estimates.

This type of program might be financed by direct federal appropriation or by a voluntary or mandatory fee on new coal-based facilities. For example, such a facility might pay \$5 per tonne of CO₂ into a fund that would be matched by a like amount from federal funds. The sequestration funds would be spent on a limited number (say 10) sequestration projects for at most 10 years.

A variation on this program would be the establishment of federal CO₂ sequestration sites for non-EOR sequestration before a carbon price makes private sites profitable.

In addition, a system of “bonus” allowances could be implemented where one tonne of sequestered CO₂ earns credit for more than one tonne. See Chapter 10 for details of this risk-reduction mechanism.

State PUC Actions: A finding by the public utility commission of a state in which a CCS facility is located that carbon capture, transport, and sequestration charges are just and reasonable would allow cost recovery for the incremental costs of CCS through the rate base. Similarly, a CO₂ pipeline might be entered into the rate base if it is found to be just and reasonable, and if the pipeline is used and useful.

“A finding by the public utility commission of a state in which a CCS facility is located that ... [CCS] charges are just and reasonable would allow cost recovery ... through the rate base.”

Similar to recent legislation in Indiana, “no look-back” provisions would be required to ensure that investors have adequate security that the terms of such an approval would not be changed after plant or pipeline construction.¹⁴ In other words, Indiana has agreed to a covenant that explicitly provides that “neither the commission, nor any other state agency, political subdivision, or governmental unit may take any action” that has the “effect of limiting, altering, or impairing a utility’s right to recover costs” in connection with, or resulting from, a contract to purchase substitute natural gas.^{15, 16} Specifically, if the Indiana Utility Regulatory Commission (the commission) approves a utility contract for the purchase of substitute natural gas, or electricity generated in connection with the production of a substitute natural gas, the commission must allow the utility to recover, on a timely basis throughout the duration of the contract, all costs incurred under a contract to purchase of substitute natural gas, as well as all related costs for generation, transmission, transportation, and sequestration.¹⁷ Moreover, the commission is prohibited from taking any action during the contract term that would adversely affect a utility’s right to timely recover costs, regardless of any changes in market conditions or other similar circumstances.¹⁸

State Electricity and Natural Gas Excise-Tax Forgiveness or Tax Credit for Energy Required for CO₂ Pipelines and Underground Injection: Many states levy an excise tax on the sale of electric power. For example, Pennsylvania charges a Gross Receipts Tax of 59 mills (5.9%) on all power sold to an end-use consumer within the Commonwealth (wholesale transactions between generators and load serving entities are not subject to the tax).¹⁹ Electricity generated in Pennsylvania and sold to another state is subject to the Gross Receipts Tax if a similar tax is imposed by that state on power generated in that state and sold into Pennsylvania.²⁰ Maryland’s Gross Receipts Tax is 2%. These taxes generally range from 2% to 4%, although some are as low as 0.6%. Ohio does not have a Gross Receipts Tax but does have an explicit tax on the consumption of electricity.

States that wish to encourage investment in transport and sequestration of CO₂ could exempt from this tax those uses of electric power directly relating to pumping and injection.

A CCS Trust Fund: A proposal developed for the Pew Center on Global Climate Change by Naomi Pena (Pew) and Edward Rubin (Carnegie Mellon

¹⁴ Indiana House Enrolled Act, Bill No. 1722.

¹⁵ Indiana House Enrolled Act, Bill No. 1722, Section 9.

¹⁶ “Substitute natural gas” means pipeline-quality gas produced by a facility that uses a gasification process to convert coal into a gas capable of being used by a utility to supply end-use consumers with gas utility service, or as a fuel used to produce electric power to supply electric utility service.

¹⁷ Indiana House Enrolled Act, Bill No. 1722, Section 9.

¹⁸ Indiana House Enrolled Act, Bill No. 1722, Section 9.

¹⁹ 72 Pa. C.S. §8101(b)(1).

²⁰ 2 Pa. C.S. §8101(b)(2).

University) envisions a generation fee on coal-fired electric power generators.²¹ The proposal is that the fee would go to a trust fund for carbon-capture and sequestration projects. A fee of 0.04 to 0.05 cents per kWh would support a program of \$7-10 billion per year, providing the incremental CCS costs for both new plants and retrofits of existing plants in a 10-plant test program. If the fee were 0.11 to 0.14 cents per kWh, the trust fund would support a 30-plant program. The fees may be lower if plants provide project cost-sharing. Uncertainties associated with this proposal include who should administer the trust fund, and whether including the fees in customer bills requires approval by each state's public utility commission or can be authorized by federal legislation.

Such federal legislation was introduced²² in June 2008 as H.R. 6258 by U.S. Representative Rick Boucher (D-VA), Chairman of the House Energy and Air Quality Subcommittee, and 14 co-sponsors.

An alternative manner of implementing such a fee may be a proactive industry initiative, similar to the 1988 "Pork. The Other White Meat.[®]" marketing fee, where Federal legislation enabled a 2/3 vote of pork producers to levy a mandatory assessment on all producers. Another funding mechanism for non-power plants might be the sort of fee per tonne of CO₂ emission discussed in the foregoing section.

The Pew study authors point out that the use of an independent or quasi-public trust fund entity would both ensure private-sector contracting and staffing standards and avoid the annual federal appropriations process. For example, the programmatic aspects of the fund should be managed by an independent, non-profit organization under contract with the federal government and selected through a competitive bid process. Additionally, the government should utilize the competitive bid process to select a private bank to handle the accounting, investment, and distribution of fund assets. Optimally, the bid contract timeframe should either be for five years with a five-year option to extend, or for ten years with a five-year break-off point. The option to extend emphasizes the need for contingency, whereas the use of a break-off point emphasizes the importance of program stability and commitment.

Congressional approval would be necessary to authorize the creation of a CCS trust fund. However, because the existence of a congressionally-approved fund does not alone generate money (i.e., it merely receives and distributes the fund assets), Federal legislation detailing how, from whom, and where the funds

21 Pena, N.; Rubin, E.S., *A Trust Fund Approach to Accelerating Deployment of CCS: Options and Considerations*; Pew Center on Global Climate Change: Washington, DC, 2008; http://www.pewclimate.org/white_papers/coal_initiative/trust_fund, and Rubin, E.S., *Accelerating Deployment of CCS at U.S. Coal-Fired Power Plants*. In *Proceedings of the 6th Annual Conference on Carbon Capture and Sequestration*, Pittsburgh, PA, 7-10 May 2007.

22 http://thomas.loc.gov/home/gpoxmlc110/h6258_ih.xml

“A Carbon Sequestration Investment Fund might be a more flexible (and cost-effective) alternative to the sort of performance standards favored by some.”

will be generated is also needed. As noted in the Pew proposal, clear objectives must be established and it must be reiterated that the fees from the trust fund to the project would terminate when the objectives are reached. Therefore, federal legislation must also establish general project mandates, specific criteria for measuring project performance, and layout at least a moderate-level detail regarding implementation—too little detail would provide no guidance, but too much detail could lead to unproductive earmarking.

The Pew study authors note that there is a continuum of trust funds, including purely federally-administered ones like the highway trust fund (supported by fuel taxes), funds managed by a consortium of stakeholders like the Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources Fund (administered under Department of Energy oversight), and the Tobacco Master Settlement Agreement (dispersed by the National Association of Attorneys General).

Such a program could provide incentives for CCS plants using a number of different technologies in various geographic regions, with sequestration in geologic formations of different types.

Carbon Sequestration Investment Fund: Similar to the CCS Trust Fund idea, a program could be developed that would enable projects to agree to make a certain level of sequestration investment as part of their qualification for other government incentive programs. This concept is aimed at providing a mechanism for projects to make firm commitments to CO₂ sequestration initiatives (funding commitments), but not be forced to make commitments to sequester certain tonnage amounts since the technological success and costs of geologic sequestration remain unknown. Under this type of mechanism, only projects that capture CO₂ could qualify. These projects would develop sequestration plans and commitment to invest a certain amount in geologic sequestration activities. For example, for every tonne of CO₂ that they produce, they could agree to spend \$3 per tonne, or \$12 million per year for a 4 Mt plant, on geologic sequestration activities. The commitment would be the basis for the projects qualifying for tax incentives, loan guarantees, or other incentives available for gasification (or other coal technology) projects.

A Carbon Sequestration Investment Fund might be a more flexible (and cost-effective) alternative to the sort of performance standards favored by some. Like other voluntary programs implemented prior to regulations, this investment fund may greatly reduce the costs of technologies prior to their economy-wide implementation.

A Carbon Sequestration Registry: If CO₂ sequestered in the near-term was accounted for by a respected party, and leakage was similarly monitored or appropriately estimated, such a registry might enable a private entity to buy and sequester carbon dioxide in the expectation that they could monetize the sequestered CO₂ when the U.S. creates a regulatory environment that supports carbon dioxide trading. Such a carbon venture fund would be expected to lobby to ensure that pre-existing sequestration projects were counted in legislation that enables any such regime, perhaps as offsets.

The Voluntary Reporting of Greenhouse Gases Program, established under Section 1605(b) of the Energy Policy Act of 1992, records the results of voluntary measures to reduce greenhouse gas emissions. For the 2005 reporting year, 221 U.S. companies and other organizations reported to the Energy Information Administration (EIA) that they had undertaken 2,379 projects to reduce or sequester greenhouse gases in 2005. The 1605(b) voluntary registry was the first of its kind in the U.S., but the results of the registry have not been well received by environmental and other organizations interested in fostering real greenhouse-gas emissions reductions. The fundamental problem with the registry in terms of accounting for real reductions is that the program allows firms to report on successful emissions reduction projects, while remaining silent on whether their overall emissions levels have increased or decreased. A recent study conducted at the University of Michigan found that for electricity-generating companies the program has no statistically significant effect on a firm's carbon intensity (i.e., its carbon emissions per unit of electricity generated).²³

Successful implementation of a registry that could provide the basis for granting emissions credit in a regulatory program or providing the basis for credit sales will require careful consideration of how to ensure registered credits are real, verifiable, and additional (e.g., not “anyway” tones—credits for doing what the company would do anyway). California is currently working on developing a registry that may serve as a template for a national program.

Allocation of government incentives: The Energy Policy Act of 2005 contains a number of incentives, including investment tax credits and Federal loan guarantees. Allocation of effective incentives that become over-subscribed is a difficult policy issue. Investment tax credits for IGCC have been over-subscribed by as much as three times (for bituminous fuel), and for industrial gasification by over seven times. The loan guarantees for gasification contained in the Energy Policy Act of 2005 have not yet been

“Successful implementation of a registry ... will require careful consideration of how to ensure registered credits are real, verifiable, and additional ...”

23 Lyon, Thomas P.; Kim, Eun-Hee, *Greenhouse Gas Reductions or Greenwash?: The DOE's 1605b Program*; November, 2006; <http://webuser.bus.umich.edu/tplyon/>

“When compared to the variability of the price of electricity [with time of day, week and year], ... the cost of emitting CO₂ may be comparatively stable.”

fully implemented by the responsible federal agency, nearly two years after the passage of the legislation.

Both issues are critical for investors in these multi-billion dollar projects.

Implementation of the 2005 EAct provisions should be a very high priority; Congress should ensure that the Department of Energy executes its responsibilities under the 2005 EAct with no further delay. The three applications for gasification loan guarantees selected on October 8, 2007 should be expeditiously processed and similar loan guarantees should be implemented for additional projects.

9.3 Allowing Flexibility During Operations

Unlike the decision to build a plant, which is based on achieving a certain return from the funds invested, under a tax or a cap and trade scheme the decision to operate a plant is based on whether the marginal operating costs can be covered by the revenue generated. Recovering the capital costs is not included in that decision, since at that time they have become “sunk costs.” So an expensive CCS-capable facility that was constructed based on an expected regulatory future may end up operating despite being unable to meet its loan payment schedule.

When compared to the variability of the price of electricity, which can fluctuate dramatically over the course of a day (from peak to off-peak periods), over the course of a week (from weekdays to weekends), and over the course of a year (from summer to winter), the cost of emitting CO₂ may be comparatively stable (set either by a tax or market). This could create times of the year when the return from not using the CSS equipment (and incurring the significant associated energy costs) could more than cover the extra costs that venting CO₂ to the atmosphere and paying for the emissions that would incur. This, of course, depends on:

- 1) what the plant is allowed to do (e.g., can it operate while venting CO₂?);
- 2) the ability of the plant to curtail part of its operations (e.g., turn off the compressors or pumps); and,
- 3) the ability to regain the “saved” energy (either in increased electricity output or reduced heat rate).

Given the uncertainty in the electricity and carbon markets, having the “option” to operate the plant in one of four ways (i.e., off, full-CCS, partial capture but no sequestration, or as a straight plant with no CSS) could have real value to the operator and investor. Depending on its magnitude, this option value could be sufficient to help encourage “fence sitters” to invest.

A fundamental insight from financial option theory is that without uncertainty an option has no value and, depending on the problem, increasing uncertainty increases the value of the option. If the long-term future carbon price was known with certainty, then the need for an option that allowed a CCS facility to operate in different configurations would be very low. High carbon prices would favor a plant that could capture and sequester a large percent of its carbon emissions, while low prices would favor a plant that vented and “paid the penalty.” To demonstrate this option value, a simple case study was developed for a new 500 MW pulverized coal plant. Figure 9.1 shows the performance (annual operating profit) for these two designs for different carbon costs (in dollars per tonne CO₂).

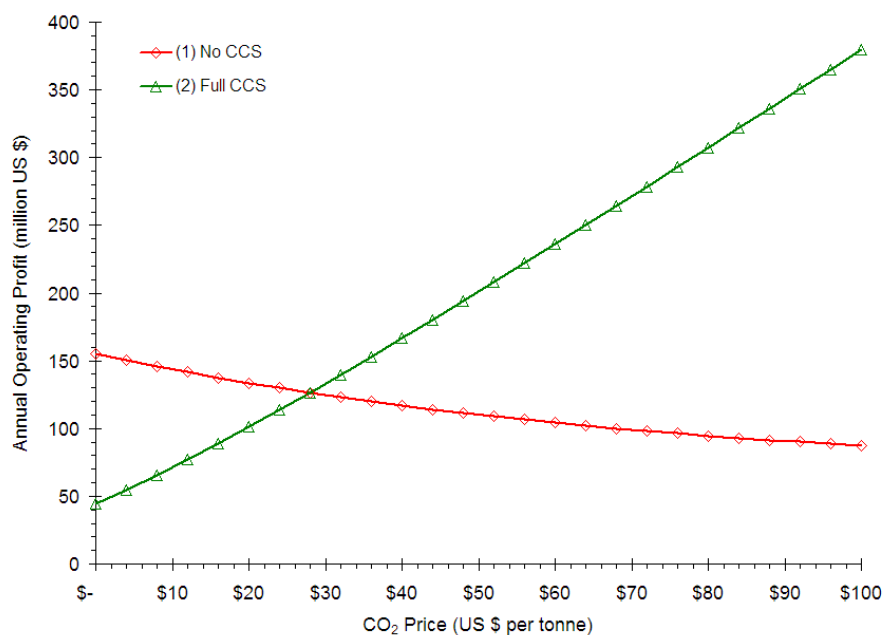


Figure 9.1: Operating profit for two PC 500 MW plants: (1) with no CCS equipment venting 100% and paying the CO₂ price per tonne, and (2) with 90% CO₂ capture and sequestration.

Determining the value of having the option to operate the plant in different ways requires engineering and financial modeling skills. As compared to a design constructed with a goal of capturing as much CO₂ as possible, a design that provides flexibility in how a plant can operate could look very different. It might be financially beneficial to “give up” some capture effectiveness in order to gain operational flexibility. For example, while an IGCC plant with full CCS might provide the most cost-effective way to capture large portions of the carbon emission, a PC plant with post-combustion capture might provide

“It might be financially beneficial to ‘give up’ some capture effectiveness in order to gain operational flexibility.”

more options for regaining energy if venting.

Figure 9.2 shows the profit profile for a plant that could either fully sequester or vent and capture 50% of the energy saved. If the uncertainty in the carbon price follows the distribution shown, the option value exceeds by over 5-10% the profits earned from either a full-vent or full-CCS plant depending on the distribution assumptions.

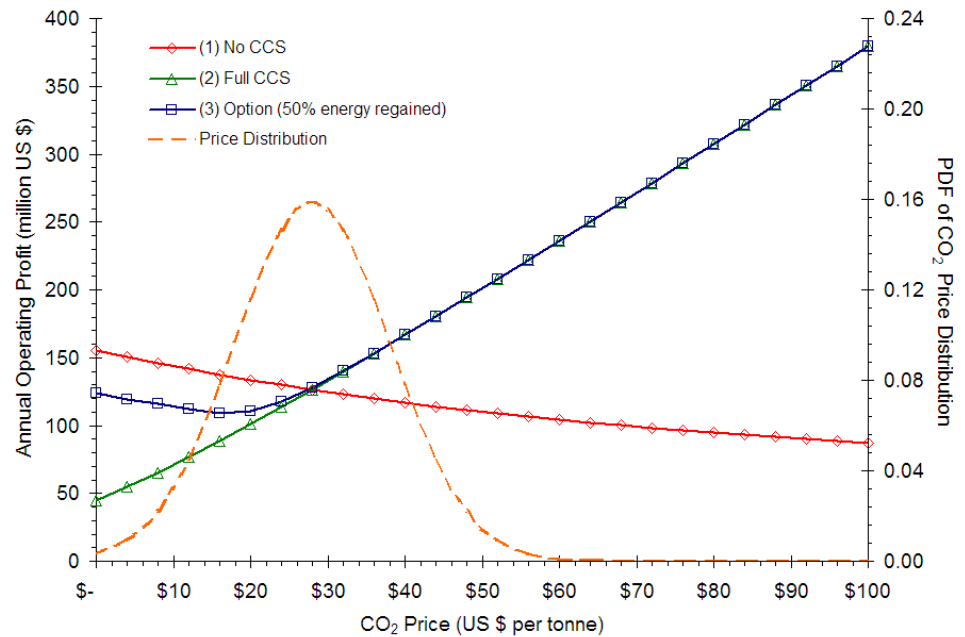


Figure 9.2: Operating profit for two PC 500 MW plants: (1) with no CCS equipment venting 100% and paying the CO₂ price per tonne, (2) with 90% CO₂ capture and sequestration and (3) option of operating in a full-vent or full CCS configuration. Also shown is the distribution of expected future CO₂ prices.

Numerous assumptions, both engineering and financial, lie behind this preliminary case study. Yet to be fully explored are the operating characteristics of plants when cycling between venting and CCS modes. The more quickly that the plant can react to changes in the electricity and carbon markets, the more profitable the “option” to operate in different configurations will be. However, because of engineering limitations, it may be impractical if not impossible to cycle on an hourly or even daily basis. Also critical to this analysis is how the carbon costs are “passed through” to the electricity prices. A price of \$50 per tonne for emitted CO₂ will certainly affect the cost of producing a MWh from a coal plant and to a lesser degree from a gas turbine plant. How does this shift the off-peak and peak prices? If most if not all of these additional costs pass through, then penalty for venting is minimized and

the benefits for CCS are small. This pass through percent will vary across the country because of differences in generating technology mixes. Any pass through will also affect demand for electricity.

Regulations could be written that block this flexible operating scenario from occurring. Regulators could force the CCS equipped plants from venting by requiring a certain captured tonnage or percent per year in order to gain tax incentives or other advantages. However, such a limitation might act to slow private capital investment in CCS.

Looking out further, regulations and carbon taxes and markets will have medium- to long-term effects on commodity markets (e.g., potentially decreasing coal prices and increasing natural gas prices). This in turn will affect future new plant construction. The recent drop in natural gas prices caused by the economic downturn has caused some gasification projects to be reconsidered. This could in turn lead to an increased demand for natural gas and subsequent increase in its price.

9.4 Summary

Over the coming months, we will continue to refine and evaluate the several options outlined in this chapter. Our objective is to elaborate further the pros and cons of each, paying attention to how each might interact with other policy initiatives.

We then plan to develop a set of specific recommendations of policies that we believe will best encourage the large private investments needed to make the commercial-scale capture, transport and deep geological sequestration of CO₂ viable in a manner that is also safe, environmentally sound, compatible with evolving international carbon-control regimes (including emissions trading), and socially equitable.

Chapter 10: Treatment of CCS Under A Domestic Greenhouse Gas Regulatory Program

In designing a CCS regulatory framework, it will be wise to consider the possible alternative greenhouse gas (GHG) regulatory programs that will drive the deployment of CCS. Such GHG regulatory programs can take a number of basic approaches, including a cap-and-trade program, a carbon tax, a sector-specific performance standard,¹ conventional command-and-control regulation, or a combination of one or more of these.² Under any of these programs: CCS would need to be recognized as a compliance option; regulators would have to assure themselves that CO₂ injected to create an emission reduction remains sequestered; and, policymakers would need to decide what financial incentives (if any) are necessary or appropriate to encourage commercial deployment of CCS. This chapter addresses how a GHG regulatory program would deal with these issues. We focus mainly on cap-and-trade programs, because most current federal legislative proposals for regulation of GHGs rely on this mechanism in whole or part.

10.1 Key CCS Issues Under Cap-and-Trade and Other GHG Regulatory Programs

There is no standard design for a GHG cap-and-trade program. A “downstream” cap-and-trade program would allocate or auction a fixed number of tradable allowances to emitters and requires those emitters to surrender allowances equal to their emissions in a particular compliance period.³ An “upstream” program, on the other hand, would require firms to surrender allowances equal to the carbon content of the fuel they distribute in commerce each year.⁴ A regulatory program can combine both upstream and downstream elements.⁵

The choice of an “upstream” or “downstream” program has important regulatory implications for the deployment of CCS. Under a downstream system, emitters (such as power plants and large industrial sources) are responsible for submitting allowances to cover their emissions. If the facility captures and permanently sequesters CO₂, then no emission occurs and no allowance submission should be necessary, so long as regulators are satisfied that the CO₂ will not leak back into the atmosphere.

In an upstream system, giving credit for sequestration is more complicated. Here, the point of regulation is not the emitter, but rather a producer, processor, or distributor of the fuel that the emitter combusts. The producer, processor,

“The choice of an ‘upstream’ or ‘downstream’ program has important regulatory implications for the deployment of CCS.”

¹ For a discussion of how a carbon portfolio standard might be used in the context of electric power see: Apt, J.; Keith, D. W.; Morgan, M. G., Promoting low-carbon electricity production. *Issues in Science and Technology* 2007, 23, (3), 37-43.

² For a description of the various design options for a U.S. GHG regulatory program, see generally, Nordhaus, R.R.; Danish, K.W., Assessing the options for designing a mandatory U.S. greenhouse gas reduction program, *Boston College Environmental Affairs Law Review* 2005, 32, 97.

³ *Id.* at 127-129.

⁴ *Id.* at 129-133.

⁵ *Id.* at 133-134.

“During the early years of a cap-and-trade program... a tonne-for-tonne allowance credit... may not provide an adequate incentive to undertake CCS.”

or distributor is required to submit allowances to cover the carbon content of that fuel. The cost of allowances is built into the price of fuel sold to the downstream emitter. However, because the emitter has no allowance submission requirement, it has no incentive to sequester unless some form of sequestration credit is provided. For that reason, a well-designed upstream cap-and-trade program would provide a sequestration credit to downstream entities that sequester CO₂ produced from fuel that was subject to an upstream allowance submission requirement. As more fully described below, several current legislative proposals combine elements of upstream and downstream regulation.⁶

A cap-and-trade program, whether upstream or downstream, presents two further design issues related to CCS: financial incentives for CCS, and potential surface leakage.

Financial Incentives for CCS Under Cap-and-Trade: During the early years of a cap-and-trade program when allowance prices are relatively low and CCS technology presumably immature, a tonne-for-tonne allowance credit (or avoided allowance submission) may not provide an adequate incentive to undertake CCS. For example, if a CCS project costs \$50 per tonne to sequester CO₂ and allowance prices are \$20 per tonne, sequestering a tonne of CO₂ (at \$50) to avoid submitting an allowance (at \$20) is uneconomic.⁷ For that reason, a number of current legislative proposals provide for “bonus allowances” in the early years of the program.⁸ Bonus allowances can raise the ratio of allowances granted to tonnes sequestered (the “crediting ratio”) to well above 1:1.⁹

For example, if we were to assume a crediting ratio of 2:5, then sequestering one tonne of CO₂ (costing \$50) would earn 2.5 allowances (worth \$50), thereby covering the cost per tonne of CCS. Obviously, if allowance prices, or CCS costs, differ from those in the example, or a different crediting ratio is provided, the CCS project would be over- or under-compensated. We discuss below this possibility (Section 10.4.) and how current legislative proposals deal with this question (Section 10.3).

Surface Leakage: A second design issue for CCS is the regulatory treatment under a cap-and-trade program of surface (atmospheric) leakage of CO₂ injected into a geologic formation in connection with CCS projects. The literature surrounding this issue acknowledges that surface leakage of carbon

⁶ See *infra* Section 10.3.

⁷ In this example, for purposes of simplicity, we do not distinguish between cost per tonne sequestered and cost per tonne of avoided emissions. See discussion *infra* note 21.

⁸ See *infra* Section 10.3.

⁹ The Lieberman-Warner Climate Security Act of 2007, S. 2191, 110th Cong. § 3603 (2007), provided a bonus allowance rate of up to 4.5:1 (a “credit ratio of 5.5:1”). The Lieberman-Warner Climate Security Act of 2008, S. 3036, 110th Cong. (2008), a later version of the bill, lowered the bonus allowance rate to a high of 2 in calendar year 2012 (a “crediting ratio” of 3:1). S. 3036 § 1013.

dioxide from sequestration projects could trigger conventional tort liability if such leakage leads to personal injury or property damage.¹⁰ Less frequently addressed in the literature, but equally important in a cap-and-trade program, is how to approach surface leakage from a regulatory and accounting perspective under such a program. In a cap-and-trade system, emissions need to be monitored and reported for the program to work. If surface leakage of CO₂ occurs after sequestration, it raises the possibility that sources could earn credit for injection of CO₂ that is not permanently sequestered. Surface leakage, thus, becomes an accounting question for the regulators in addition to a liability issue for the trial lawyers. This regulatory accounting question is discussed in section 10.4 below.

CCS Under Other GHG Regulatory Regimes: GHG regulatory programs other than cap-and-trade present many of the same issues as those described above. For example, a carbon tax faces upstream regulation issues similar to those under a cap-and-trade system. Specifically, if the carbon tax is imposed upstream of the point of emission, a facility that sequesters CO₂ rather than emitting it, must be given a tax credit for sequestration in order for there to be any incentive to sequester. And, if the cost to sequester exceeds the carbon tax rate, financial incentives may need to be provided. Finally, potential leakage can be an issue.

Similarly, in the case of a “GHG emission performance standard” (where an

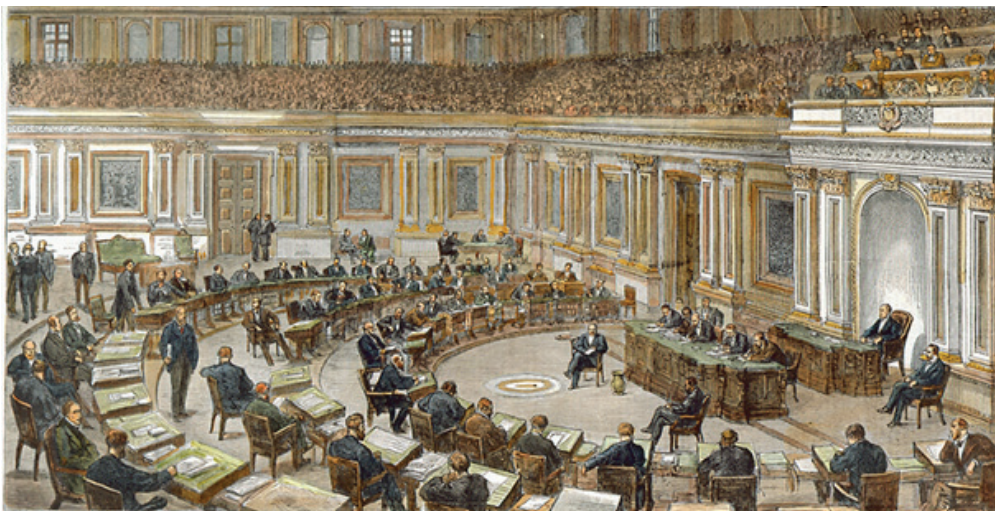


Figure 10.1: The details of each of the different approaches to limiting the emissions of greenhouse gases that are being considered by the U.S. Congress have implications for CCS. These should be considered carefully before making a final choice (photo source: U.S. Senate).

¹⁰ See, i.e., Mark DeFigueiredo, *The Liability of Carbon Dioxide Storage* (MIT) (2007).

electric utility must meet a performance standard based on maximum CO₂ emissions per megawatt hour from its own generation or long-term purchased power contracts),¹¹ proper accounting must be provided for sequestration, and potential leakage might need to be addressed. Financial incentives may or may not be necessary depending on the stringency of the performance standard.

Finally, if traditional command-and-control regulation is implemented—for example, in the form of a new source performance standard for CO₂ emissions by electric generators—sequestration by an entity other than the generator would need to be designated as a compliance option, financial incentives may or may not be needed (depending on the stringency of the standard), and potential leakage could be an issue.

10.2 Current Legislative Proposals

In the 110th Congress, a number of House and Senate proposals addressed the implementation of carbon capture and sequestration technology in the context of a national GHG reduction program. Two leading proposals are S. 3036, the Climate Security Act of 2008 (“Lieberman-Warner”),¹² and a discussion draft circulated by the House Energy and Commerce committee on October 7, 2008 (“Dingell-Boucher”).¹³ Both bills would establish cap-and-trade programs to limit emissions beginning in 2012 with continuing emissions reductions through 2050. CCS projects would qualify for sequestration credit and bonus allowances under both bills’ cap-and-trade schemes.

Lieberman-Warner: Under Lieberman-Warner, coal is regulated “downstream” at the point of combustion. Coal-fired power plants and other large coal-fired facilities must submit an emission allowance (or offset) for every tonne of CO₂ they emit. To the extent the facility captures and sequesters CO₂ produced at that facility, no CO₂ is emitted and no allowance (or offset) submission should be necessary for the sequestered CO₂.¹⁴ Oil and natural gas, on the other hand, are regulated “upstream,” at the point of refining or processing, rather than at the point of combustion. Facilities that sequester CO₂ from combustion of oil or natural gas are eligible to receive a credit for each tonne of carbon they sequester. The credit is equivalent to an emission allowance and equal to the quantity (in tonnes) of CO₂ sequestered.¹⁵

11 See, e.g., Emission Performance Standard, S.B. 1368, 2005-2006 Reg. Sess. (Ca. 2006) (limiting long-term investments in baseload generation by the state’s utilities to power plants that meet an emissions performance standard (EPS) jointly established by the California Energy Commission and the California Public Utilities Commission), codified at CAL. PUB. UTIL. CODE §§ 8340(h), 8341 (West 2008); *Order Instituting Rulemaking to Implement the Commission’s Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies*, CAL. PUB. UTIL. COMM., Rulemaking 06-04-009 (Jan. 25, 2007) (adopting an EPS as directed by SB 1368).

12 S. 3036, 110th Cong. (2008).

13 On October 7, 2008, Reps. John Dingell and Rick Boucher released a discussion draft climate change bill that is intended to stimulate discussion and serve as a basis for legislation that they plan to introduce in 2009 during the 111th Congress [hereinafter Discussion Draft].

14 The version of Lieberman-Warner finally offered on the Senate floor, if read literally, could be interpreted as requiring coal-fired power plants to submit allowances for CO₂ produced by combustion of coal even if the CO₂ is sequestered and no emission occurs. This is an apparent drafting error.

15 S. 3036, § 202(f).

Regulated entities are also eligible to receive a bonus allowance to account for the tonnes of CO₂ emissions avoided through capture and geologic sequestration of emissions by a CCS project that meets emission performance standards prescribed by EPA.¹⁶ The tonnes avoided, multiplied by that year's bonus allowance rate and a bonus allowance adjustment factor determines the allowance.¹⁷ There is a ten-year limit placed on the receipt of these allowances.¹⁸

As written, Lieberman-Warner does not provide EPA with explicit authority to address surface leakage from CCS projects under the regulatory provisions of the cap-and-trade program, and it is unclear whether EPA has authority to adjust sequestration credits to address surface leakage after the year of injection.

Dingell-Boucher: The Dingell-Boucher discussion draft establishes a cap-and-trade program that is similar to Lieberman-Warner, but differs in a number of key respects. Under both proposals, coal is regulated downstream, at the point of emission. However, in contrast to Lieberman-Warner where natural gas is regulated upstream, Dingell-Boucher regulates natural gas-fired sources downstream at the point of emissions.¹⁹ In addition, CCS projects are considered “covered entities,” and are required to account for any future leakage from the project.²⁰

The bonus allowance scheme under Dingell-Boucher represents a significant refinement. A certified CCS project would be allocated bonus allowances from calendar years 2012 through 2025. Electricity generators would be eligible for 75% of the available CCS allowances²¹ under the following formula:²²

$$\frac{(\text{Tonnes of CO}_2 \text{ emissions avoided}^{23}) (\text{bonus allowance value})}{(\text{Average value of an emission allowance during the preceding year.})}$$

The prescribed bonus allowance value for electricity sources is \$90 per tonne for early CCS projects, eventually dropping to \$50 per tonne.²⁴ These allowances are available to an electricity project for its first 10 years of operation.²⁵

¹⁶ *Id.* §§ 202(f); 1013 (a).

¹⁷ *Id.* § 1013(a).

¹⁸ *Id.* § 1014.

¹⁹ Dingell-Boucher Discussion Draft, §§ 712(a)(1), (5), (6). Electricity and industrial sources, including those sources that are natural gas-fired, are regulated downstream.

²⁰ *Id.* § 700(8)(D).

²¹ *Id.* § 724(a). The remaining 25% would be available for industrial sources that capture and sequester CO₂. *Id.* § 724(b).

²² *Id.* § 724(a)(7)(A). Allocation to industrial sources is pursuant to EPA rules. *Id.* § 724(b)(2).

²³ *Id.* § 724(a)(7)(A)(i)(1). The Discussion Draft does not define the concept of avoided emissions, but appears to recognize a distinct difference between tonnes sequestered and tonnes avoided. The concept of avoided tonnes can account for the significant energy penalty associated with CCS, and is discussed in Chapter 2. The proposed legislation requires EPA to promulgate rules establishing a methodology for determining the number of tonnes of CO₂ avoided. Discussion Draft § 724(a)(8).

²⁴ Discussion Draft § 724(a)(7)(B).

²⁵ *Id.* § 724(a)(11)(A). There is a built-in incentive to begin a CCS project sooner rather than later. While the bills commits to providing bonus allowances for 10 years, it will not allocate allowances to new projects if that would compromise the 10 years of guaranteed allowances to those projects already in progress. *Id.* § 724(a)(11)(B). For an industrial project, bonus allowances are only provided for the first five years of operation. *Id.* § 724(b)(5).

“There appears to be general agreement that some form of financial incentive... is appropriate for demonstration and initial commercial deployment of CCS.”

Both existing electricity and industrial sources would need to meet prescribed eligibility and performance standards to qualify for a bonus allowance. A new electric generating unit (EGU) would be required to capture and geologically sequester at least 60% of its total CO₂ emissions on an annual basis by January 1, 2025, or if later, the date four years after it commences operation.²⁶

Bonus allowances for new electricity projects would be cut off once cumulative generating capacity using CCS exceeded 60 GW, or if the bonus account would be oversubscribed.²⁷

10.3 Designing Financial Incentives for CCS

The issues of whether a cap-and-trade program should provide financial incentives for CCS and how to structure those incentives are particularly knotty ones. As we pointed out above, if allowance prices are low in the early years of a cap-and-trade program and costs per tonne sequestered are high, CCS will be uneconomic and is unlikely to be deployed on a commercial scale. Unfortunately, there is little agreement as to what the level of allowance prices are likely to be under current proposals,²⁸ and even less agreement as to the likely cost per tonne to sequester CO₂.²⁹ For these reasons (among others), policymakers are faced with difficult decisions on the scope of a CCS incentive program and how to structure it. There appears to be general agreement that some form of financial incentive under the cap-and-trade program (or other public subsidy) is appropriate for demonstration and initial commercial deployment of CCS.³⁰ However, questions can be raised on economic efficiency grounds as to whether long-term financial incentives should be provided for the continuing commercial deployment of CCS under a cap-and-trade program, particularly if other less expensive abatement opportunities are available.

Even if one were to assume that substantial public benefits from deployment of CCS justify long-term financial incentives, the further question arises as to how to design the incentive mechanism. The type of bonus allowance mechanism that appears in Lieberman-Warner runs the risk of under-compensating CCS projects if allowance prices are lower (or CCS costs higher) than the level assumed when the legislation was enacted, or, of overcompensating such projects if the opposite turns out to be the case. For example, if allowance prices are \$20 per tonne and CCS costs \$50 per tonne, a bonus allowance mechanism that provides 2.5 allowances for every tonne

²⁶ *Id.* § 812(b).

²⁷ *Id.* §§ 724(a)(10)(B), 724(a)(11)(B). There is no similar 60 GW limit for industrial projects, but a corresponding oversubscription limit exists if the full five-year distributions will not be provided to current eligible participants. *Id.* § 724(b)(6).

²⁸ For example, projections of allowance prices under the initial Lieberman-Warner bill vary from \$20/ton to \$70/ton in 2020. See Doug Carter, *CCS Incentives and S. 2191*, Presentation to the Coal Utilization Research Council (CURC) General Membership Meeting, Apr. 25, 2008, at 8.

²⁹ For current best estimates of capture cost, see Chapter 2. See also, *id.* at 12; George Booras, *Economic Assessment of Advanced Coal-Based Power Plants with CO₂ Capture*, Presentation to Electric Power Research Institute (EPRI), Sept. 16, 2008, at 17; Jared Ciferno, *Carbon Capture Technology Options and Costs*, Presentation at the National Energy Technology Laboratory (NETL), Sept. 3-4, 2008, at 29.

³⁰ See Carbon Capture and Storage Early Deployment Act, H.R. 6258, 110th Cong. (2008), introduced by Senator Boucher on Jun. 12, 2008.

sequestered will make the CCS project whole. But, that ratio will not provide sufficient incentive if allowance prices are at \$15 or CCS costs at \$60. And, if the allowance prices are \$40 or CCS costs \$35, the 2.5 ratio will provide the CCS project with a windfall.³¹

Moreover, this type of bonus allowance mechanism can have a particularly perverse effect if allowance prices under the cap-and-trade program turn out to be highly volatile. Bonus allowances have the least value to the CCS developer when allowance prices are low, which is precisely when the financial incentive is most needed. Conversely, when allowance prices are high and there is less need for the financial incentives, the value of the bonus allowances is highest.

If the objective is to provide financial incentives that are scaled to the reasonable needs of CCS project developers while avoiding potential windfalls, alternatives to the type of bonus allowance mechanism that appears in Lieberman-Warner could be considered. One alternative approach is presented in the Dingell-Boucher discussion draft. There, the quantity of allowances allocated to a certified CCS project varies according to allowance prices and, in any case, decreases over time as “bonus allowance value” decreases from \$90 to \$50 per tonne as more CCS projects are placed in service.³² The allocation formula, however, can lead to seemingly capricious results. For example, if bonus allowance value is \$90 per tonne for a particular project, and allowance prices are \$25 per tonne, the project receives \$360 per tonne in bonus allowances (on top of avoiding the basic requirement for allowance submission). It is unlikely that the level of financial incentive will be necessary even in the early years of the program.

For these reasons, policymakers may wish to give some further attention to bonus allowance formulae. For example:

- The incentive could be structured as a variable allowance allocation equal in value to the difference between estimated cost per sequestered tonne for CCS and current allowance price. EPA or another agency could make a periodic administrative determination of the likely cost per tonne for future CCS projects. This price per tonne and current allowance prices would provide the basis for determining the quantity of bonus allowances per tonne for CCS projects placed in service the following several years. For example, in 2020, if EPA determined that it costs \$50 per tonne to sequester

“...[a] bonus allowance mechanism can have a particularly perverse effect if allowance prices under the cap-and-trade program turn out to be highly volatile.”

³¹ As noted above, these are simplified examples that do not take into account the difference between sequestration cost and costs of avoided emissions.

³² See Discussion Draft § 724(a)(7)(B).

and allowance prices were \$20 per tonne, 1.5 bonus allowances per tonne sequestered would be allocated to projects in that year. This would provide allowances worth an incremental \$30 per tonne.

- Alternatively, the financial incentive could be provided in terms of dollars, rather than allowances. For example, the incentive could be a fixed or variable dollar payment, paid out of the proceeds of an allowance auction.

10.4 Regulatory Treatment of Potential Surface Leakage

In designing a cap-and-trade program, policymakers may decide to address potential surface leakage of sequestered CO₂, and to provide explicit direction and authority to regulators to account for it. Lieberman-Warner does not explicitly address regulatory accounting for surface leakage, but could be interpreted as providing authority to do so. Dingell-Boucher, at least in theory, addresses regulatory accounting for surface leakage from geologic sequestration projects by treating a geologic sequestration site as a “covered entity.”³³ In this section, we address the questions of whether the cap-and-trade program should explicitly require some form of adjustment in credit provided for sequestrations to reflect actual or potential surface leakage.

While the focus of this section is surface leakage of sequestered CO₂, many of the same issues are presented in connection with leakage or other releases from CO₂ pipelines. This is an issue that may also have to be addressed in the design of a cap-and-trade or other GHG regulatory program.

Potential for Surface Leakage: Creating a regulatory framework to account for surface leakage is complicated by the fact that large-scale CO₂ sequestration projects are at their early stages and the actual extent of surface leakage is not known. However, the Intergovernmental Panel on Climate Change (IPCC) Special Report on Carbon Dioxide Capture and Storage estimates that the fraction of injected CO₂ retained in appropriately selected and managed geological reservoirs is likely to exceed 99% over 1000 years.³⁴ This leakage estimate is similar to that of other organizations, including the Carbon Sequestration Leadership Forum (CSLF),³⁵ the World Resources Institute,³⁶ and the International Energy Agency (IEA).³⁷ Scientists caution, however, that the percentages are preliminary estimates and they should not be

³³ See Discussion Draft § 700(8)(D).

³⁴ Metz, B.; Davidson, O.; de Coninck, H., et al., *IPCC Special Report on Carbon Dioxide Capture and Storage*. Cambridge University Press: Cambridge, U.K., 2005; p 442. (hereinafter IPCC Report). See also Wilson E.J., et al., *Liability and Financial Responsibility Frameworks for Carbon Capture and Sequestration*, World Resources Institute Issue Brief, No. 3, 2007.

³⁵ The CSLF is an international climate change initiative comprised of 21 member countries and the European Commission, has sponsored several studies and reports on research, development and demonstration activities in CO₂ capture and storage technologies.

³⁶ Wilson E.J., et al., *Liability and Financial Responsibility Frameworks for Carbon Capture and Sequestration*, World Resources Institute Issue Brief, No. 3, 2007, at 2.

³⁷ International Energy Agency, *Geologic Storage of Carbon Dioxide Staying Safely Underground*, 2008 (hereinafter IEA Report).

used for assigning emission factors from geological storage reservoirs.³⁸

As we point out in Chapter 4, geologic sequestration is a promising means of lowering emission levels because numerous trapping mechanisms can act to permanently store CO₂ underground.³⁹ The greatest potential for leakage from geologic sequestration comes from improperly sealed and poorly documented abandoned wells⁴⁰ in sequestration sites near former oil and gas fields.⁴¹

As the IEA notes, the technology to store CO₂ underground should be considered proven technology, but questions remain whether and to what extent CO₂ will leak from underground storage sites back into the atmosphere.⁴² To investigate and determine the effectiveness of CCS, demonstration projects are occurring globally in the U.S., Canada, Australia, Asia, and Europe. The possibility of surface leakage is one factor that the projects will study. Data from these projects will be useful in determining the degree of risk of surface leakage.

Capability of Monitoring Surface Leakage: A key regulatory predicate for the U.S. acid rain program and other successful cap-and-trade programs has been that emissions can and will be accurately monitored. The conventional wisdom is that a market-based control system works only if regulators and market participants are confident that the “regulatory currency” (i.e., allowances) will not be debased by under-reporting of emissions or over-reporting of offsets. For that reason, some commentators are concerned that a cap-and-trade program that allows tonne-for-tonne or greater credits for sequestered CO₂ requires relatively precise monitoring technology that can determine whether the sequestered gas ultimately will leak back into the atmosphere.

But, in contrast to the well-developed technology for monitoring emissions from stationary sources (which can quantify emissions with a high degree of accuracy), the monitoring technology for surface leakage of injected CO₂ is less developed, and at this stage imprecise.

“... a market-based control system works only if regulators and market participants are confident that the ‘regulatory currency’... will not be debased by under-reporting of emissions or over-reporting of offsets.”

38 Benson, S. M., Monitoring Carbon Dioxide Sequestration in Deep Geological Formations for Inventory Verification and Carbon Credits. In *SPE Annual Technical Conference and Exhibition*, Society of Petroleum Engineers: San Antonio, TX, 2006. Scientists recognize that the full leakage potential is unknown until further studies are conducted. For example, the CSLF acknowledges that no party has completed a fully integrated CO₂ capture demonstration system and leakage rate data is still sparse. Carbon Sequestration Leadership Forum, Final Report from the Task Force for Identifying Gaps in Monitoring and Verification of Geologic CO₂ Storage, 2006.

39 The primary mechanism that acts to retain CO₂ in the subsurface is structural trapping under an impermeable caprock—i.e., a geologic formation presents a barrier to upwards migration of CO₂ in the subsurface. Through time, secondary trapping mechanisms improve the storage security. These include capillary forces in the pore spaces of the storage formation, dissolution in the *in situ* formation fluids, formation of mineral carbonates, and adsorption onto organic matter in coal and shale. *Id.*

40 *Id.*

41 Research is underway concerning abandoned wells, which may provide a pathway for CO₂ leakage. In a paper on the safety of CCS, the International Energy Agency Greenhouse Gas R&D Program noted that there is little evidence of leakage from abandoned wells in West Texas where CO₂ injection has been widely used for Enhanced Oil Recovery (EOR) since the 1970s. IEA Report, *supra* note 33, at 14. CO₂-flood EOR projects may not provide the best comparison, however. This technology has been developed from the viewpoint of oil recovery, not from the viewpoint of CO₂ storage. International Energy Agency *Prospects for CO₂ Capture and Storage*; International Energy Agency: Paris, France, 2004. [hereinafter IEA Prospects].

42 IEA Prospects, *supra* note 39, at 17.

As discussed in Chapter 4, it is currently infeasible to conduct direct measurement of surface leakage over the entire large land area overlying a formation in which CO₂ is sequestered. It is also infeasible to directly estimate the amount of CO₂ retained in the target formation since it is believed that the amount in place could not be estimated with greater than 20% precision.⁴³ This inability to meaningfully track the mass of CO₂ in-place will make it difficult to effectively verify whether the injected mass is escaping to the atmosphere.

Because there is no reason to believe that CO₂ would escape from a well-operated project, sequestering CO₂ in a properly selected target formation, a monitoring protocol that looks for signs of CO₂ escaping to overlying formations, and then—if there is evidence of escape—attempts to determine whether and to what extent surface leakage is occurring, may be the most feasible option at the present time. Monitoring methods available today (see Box 4.3) can detect, locate, and roughly quantify CO₂ leakage to the atmosphere from a small portion of the footprint of a sequestration project.

The method used to monitor leakage will depend on a number of factors, including: the phase of the sequestration project (i.e., injection or later); the type of geological storage reservoir used for sequestration (such as on-shore or off-shore); and, where the subsurface monitoring is to occur (within the target formation v. an overlying formation). It will be important to allow for flexibility in the implementation of any monitoring program as some sites may be better suited than others to detect and monitor CO₂ migration and a variety of technologies would be required, depending on whether the monitoring is of the subsurface or of surface-based emissions.

Options for Addressing Surface Leakage: The principal options for addressing potential surface leakage, and the pros and cons of each option, are summarized below.

Option 1—Full Credit: The first option is to provide full credit for sequestered CO₂, assuming the project complies with applicable siting requirements and engineering standards. (This is the apparent approach of Lieberman-Warner, although as noted, it could be read as giving authority to EPA to deal with leakage in connection with the cap-and-trade program.) If further research and site monitoring indicates that non-*de minimus* surface leakage of sequestered CO₂ is likely to occur, EPA would seek explicit statutory authorization to exercise one or more of the regulatory options discussed below (Options 3, 4, or 5). The imprecision of currently available monitoring techniques and the current scientific view that properly-engineered injection operations will not result in significant surface leakage both argue against attempting to impose a

⁴³ See Section 4.2 *supra*; Benson, *supra* note 36.

regulatory requirement with respect to leakage at the initial stages of the cap-and-trade program. If more precise, cost-effective monitoring techniques are perfected or if the cumbersome current monitoring techniques indicate that significant leakage is actually occurring, then the regulatory program can be modified appropriately.

Option 2—Full Credit with Back-up Regulatory: This option is the same as Option 1, except that EPA would have statutory authority—if it determined that significant leakage was occurring—to modify the cap-and-trade program *prospectively* to make sure that the leakage was taken into account under the program. This would provide injectors that complied with injection standards, and upstream facilities, with full assurance in the early stages of the program that they would receive full credit for injected CO₂ without being exposed to potential future liability if there is surface leakage. However, if new monitoring techniques became available or if existing monitoring techniques showed significant leakage, EPA could—without going back to Congress—take steps to deal with the problem on a prospective basis. Any one of the options discussed below (Options 3 through 5) could provide the basis for the back-up program.

Option 3—Allowance Repayment (in Tonnes of CO₂): A third option would be to require entities to submit emission allowances for each tonne of CO₂ that is determined to have escaped from the sequestration site. This is the apparent approach of Dingell-Boucher.⁴⁴ This system of addressing leakage would first require a reliable monitoring system that is able to determine, with some level of precision, the amount of CO₂ that has leaked into the atmosphere from the site. Any legislative provision also would have to specify the party that is responsible for monitoring the site, the frequency of monitoring, and other conditions.

Under an emissions allowance repayment scheme, the responsible party would have to submit allowances for leakage of CO₂ that already received sequestration credit. Presumably, the responsible party would be the party that received the sequestration credit under the program. As with long-term stewardship (as discussed in Chapter 7), policymakers will be concerned that the designated responsible party may not be in existence, or be solvent, well into the future when leakage may occur. Thus, financial responsibility provisions are likely to be necessary if an allowance repayment approach is adopted. Financial responsibility provisions could take the form of an

⁴⁴ See Dingell-Boucher, § 712(a)(4).

insurance requirement, surety bond, or contribution to a leakage reserve (see below).⁴⁵

Finally, a key issue in any allowance repayment scheme would be allocating liability for leakage among multiple responsible parties in circumstances where a number of entities injected CO₂ into the same reservoir and each received credit for the CO₂ they injected.⁴⁶

Option 4—Discounting Tonnes of CO₂ Sequestered: This option would account for surface leakage from CCS projects by up-front discounting of the tonnes of CO₂ sequestered.⁴⁷ For example, under this type of program, if an entity sequesters 10 million tonnes of CO₂, and a 10% discount factor is used, only 9 million tonnes would be treated as captured and sequestered and the entity would be required to submit emission allowances for the remaining 1 million tonnes. The most important aspect of this approach is determining the amount by which each sequestered tonne is discounted. Estimates of potential leakage from CCS sites vary: the IPCC projects less than 1% over 1,000 years; site-specific estimates will depend on the project design and site geology.⁴⁸ Lawmakers or regulators would have to decide on which estimate to base such a program. Further, it may be desirable to use a lesser discount factor—or none at all—in the early years of CCS projects in order to encourage deployment of CCS technology.

A discounting program could also address whether the discounted amount for which an entity has submitted allowances would be paid back or credited to the entity if leakage does not occur or if leakage occurs at a rate less than the discounted amount.⁴⁹ A discounted sequestration scheme could also address the possibility that leakage would occur at rates greater than the discounted amount and whether this situation would require additional allowance submissions.⁵⁰ Finally, as with any strategy to address surface leakage, a reliable monitoring program is a fundamental part of the program.

⁴⁵ A legislatively-established repayment program will have to identify the ratio of leakage amount to repayment liability. At least after the early years of any CCS program, the repayment amount presumably would be equal to the amount of leakage in order to fully account for the leakage of CO₂. However, a program to address surface leakage initially could impose a repayment ratio of less than one-to-one, to avoid discouraging widespread deployment of CCS technology.

⁴⁶ A further complication relates to the possibility that some sources may sequester directly and have zero allowance liability rather than receiving credits.

⁴⁷ For discussion of the efficiency implications of discounting see Ha-Duong, M.; Keith, D. W., Carbon storage: the economic efficiency of storing CO₂ in leaky reservoirs. *Clean Technologies and Environmental Policy* 2003, 5, (3-4), 181-189.

⁴⁸ See Benson, *supra* note 36.

⁴⁹ Lawmakers or regulators would have to consider the point in time at which repayment would occur, how repayment would be funded, and whether repayment could be in the form of emission allowances established under the cap-and-trade program.

⁵⁰ If allowances are required to be submitted to cover surface leakage, the program must specify the entity or entities that would be liable for this submission obligation. This could become particularly complicated if a storage site is utilized by numerous CO₂ emitters. Furthermore, as with the repayment liability option discussed above, a discounting program would have to determine how far into the future the obligation to submit allowances for leakage would extend, and which entities would be responsible.

Option 5— Leakage Reserve: A fifth option for accounting for surface leakage is a “leakage reserve.” A “leakage reserve” would be an allowance pool that could be drawn down if leakage occurs. The leakage reserve could be funded with a small proportion of the allowances that otherwise would be awarded to CCS projects as bonus allowances or sequestration credits. A small fixed or variable percentage of the allowances or credits awarded to each company could be treated as an insurance premium and placed into a leakage reserve to be used in the event that there is leakage from the CCS site. The “premium” amount could vary, depending on the risk of the specific project. For example, the percentage of bonus allowances and CCS credits placed in a leakage reserve could vary based on site suitability, with higher amounts required for those sites that encompass previously used oil and natural gas drilling wells, and lower amounts for geological formations that have not yet been penetrated.

A leakage reserve option would raise many of the same issues as the discounted sequestration or allowance repayment schemes discussed above, including the size of the reserve pool, and deciding on the entity to be responsible for initially submitting allowances or submitting additional allowances if the leakage exceeds the reserved amount for that site. Policymakers may also wish to consider whether, and when, these allowances would be repaid to the entity initially submitting the allowances, in the event that surface leakage does not occur or occurs at a rate that is less than the amount of allowances submitted.

Conclusions and Recommendations Respecting Surface Leakage: Because current monitoring technology cannot feasibly measure surface leakage of sequestered CO₂ with any degree of precision, Options 3, 4, and 5 appear to be difficult or impossible to implement at the inception of the cap-and-trade program. Moreover, current scientific assessments compiled by the IPCC suggest that the cumulative leakage may be less than 1% of injected CO₂ over the course of 1,000 years if the CO₂ is injected and stored properly.⁵¹ If the amount of potential leakage is as low as the IPCC estimates, the impact on atmospheric concentrations could be negligible, obviating any need to account for surface leakage emissions in a cap-and-trade system.⁵²

Thus, both the limitations on current monitoring technology and current scientific opinion as to the likelihood and magnitude of leakage argue against imposing a repayment, discount or leakage reserve requirement (Option 3, 4, or 5) at the inception of a cap-and-trade program. Rather, they suggest that the better course would be Option 1 or 2: that is to focus the initial regulatory

⁵¹ IPCC Report, *supra* note 32, at 197.

⁵² For a discussion of the climate efficiency of leaky storage, see Teng, F.; Tondeur, D., Efficiency of Carbon storage with leakage: Physical and economical approaches. *Energy* 2007, 32, (4), 540-548. and Ha-Duong, M.; Keith, D. W., Carbon storage: the economic efficiency of storing CO₂ in leaky reservoirs. *Clean Technologies and Environmental Policy* 2003, 5, (3-4), 181-189.

effort on selection of appropriate sequestration sites and postponing any regulatory requirement respecting leakage until either 1) cost-effective monitoring technology is available—in which case, any of the last three options could be implemented; or 2) existing monitoring technology indicates that surface leakage is a substantial problem—in which case Option 4 (discounting) could be implemented in some form.

Chapter 11: Next Steps

Our motivation is simple—we believe that climate change is a serious threat to the world, its peoples, and its ecosystems. We see no politically and economically plausible way to achieve an 80% reduction in the emissions of CO₂ over the course of the next half century without some use of fossil fuels coupled with CCS. Of course, fossil fuels and CCS are only part of a portfolio of solutions, which also includes dramatically increased energy efficiency and the adoption of a variety of renewable and other low-carbon energy sources.

This leads to an obvious desire to get a final and definitive regulatory framework for CCS in place as quickly as possible. Indeed, we note in Chapter 3 that it would be especially desirable to put a clear framework in place for the regulation of CO₂ pipeline rates and access so that project sponsors will have greater certainty about the ground rules by the time that the first commercial-scale CCS projects are ready for deployment.

However, at several places in this report, we also suggest that before finalizing a U.S. regulatory framework to govern the operation of CCS, it is important to gain substantial experience from a number of commercial-scale projects (i.e., ten or more) undertaken in a variety of geological settings both here in the U.S. and around the world. In the interim, existing regulations, perhaps augmented by the new rules now under development by the EPA, should be sufficient to allow initial large-scale CCS projects to go forward in the U.S. We term this strategy of learning from field experience a “two-stage” approach to regulation.

In a paper published in *Environmental Science and Technology* in the spring of 2008,¹ several of us outlined one way to implement such a “two-stage” approach with learning. In this paper, we noted that:

...there is considerable risk that after mounting a number of large demonstration projects, a transition to continued commercial development could occur without drawing on lessons learned and developing appropriate new national regulatory frameworks. To avoid this in the U.S., while assuring a rapid transition to a more permanent regime, we propose the creation of an independent Federal Carbon Sequestration Commission. This Commission should be given a fixed life, have a presidentially-appointed chair, and consist of approximately 15 members drawn from a wide range of relevant experts and public and private stakeholders. While it

“...before finalizing a U.S. regulatory framework to govern the operation of CCS, it is important to gain substantial experience from a number...of commercial-scale projects...”

¹ Wilson, E. J.; Morgan, M. G.; Apt, J., et al., Regulating the Geological Sequestration of Carbon Dioxide. *Environmental Science and Technology* 2008, 42, (8), 2718–2722.

“We hope that readers will assist us [with] ... critical comments ... and suggest arguments that should shape the final recommendations we develop”

would observe and comment, the Commission would not have administrative control over DOE or other injection projects and would have no regulatory authority.

The charge to this Commission should be to track all U.S. and international projects and gather data that can be used to develop recommendations for regulatory needs for commercial-scale operations. The Commission should make annual progress reports to the Administration and to Congress that includes recommendations on additional projects needed to gain insight... The Commission should be required to provide a report to the Administration and to Congress on the form that regulation for widespread commercial-scale operation should take on or before a specified sunset date (e.g., 2015).

Members of the CCSReg project continue to believe that the prompt creation of such a Presidential or Congressional Commission would be a good strategy and might have the added advantage of building informal international ties with other nations that are also engaged in building CCS programs.

Many general issues such as pipeline siting, access to pore space, and the approach to long-term stewardship can be addressed now. However, specific regulatory details should not be resolved until they can be informed by the Commission’s insights.

In this interim report, we have worked to frame the issues that we believe must be addressed if the U.S. is to develop an institutional, legal, and regulatory framework for the safe and effective adoption of a large commercial-scale program of CO₂ capture and deep geological sequestration. Over the coming months, we plan to use this report as the basis for a number of workshops and informal consultations with a wide range of experts and interested stakeholders with the objective of refining our thinking and developing a set of specific recommendations (that may include some draft language for new enabling legislation).

It is our hope that readers will assist us in this process by sending us critical comments on the way in which we have framed the issues, help us to identify things that we may have overlooked, and suggest arguments that should shape the final recommendations that we develop.

Contact information for us is provided inside the front cover of this report. Thank you in advance for any advice that you can offer.

Appendix A: Regulatory Developments in Other Nations

This appendix complements discussion of the U.S. regulatory framework for CCS, found principally in Chapter 6 of the body of the report. The goal of this chapter is to put regulatory developments in the U.S. in the context of those in the EU and Australia.

A.1 European Union Regulatory Proposal

After careful analysis of existing regulations, the European Commission (EC) concluded that new, freestanding rules were needed for geological sequestration (GS) of CO₂.¹ The proposed GS directive was introduced in the European Parliament in January 2008 as part of a comprehensive energy and climate legislative package.² The European Parliament has not yet brought the energy and climate package up for a vote. If it does pass, each member state would then need to pass legislation implementing the CCS directive.

Policy drivers for CCS in Europe are complex. Some Member States depend heavily on coal for electrical power generation. Anti-nuclear sentiment is also a factor. While Europe is a net coal importer, coal production is still important to some economies. The European Union (EU) is a signatory to the Kyoto Protocol, and a carbon market, the EU Emissions Trading System (EU ETS) is up and running. CCS is being considered for inclusion in Phase II of the EU ETS, starting in 2008, and the IPCC has published GHG inventory accounting guidelines for CCS projects.³ Recent activity in the European Parliament is aimed at facilitating CCS deployment. An amendment to the energy and climate package has been introduced that would create an emission performance standard for electrical power. Power plants built after 2015 with a capacity of more than 300 MW would be limited to emissions of 500 g CO₂/kWh. Another amendment would provide funding for 12 demonstration projects to be secured by ETS allowances.

The proposed EC GS directive would establish minimum permitting requirements to be implemented by Member States, much like the U.S. EPA Underground Injection Control (UIC) Program sets minimum standards to be implemented by the states. The proposed directive's goals are broad: it specifies that GS projects must show they would cause no significant negative health or environmental impacts, and that the injected CO₂ would be permanently contained with no significant risk of leakage.

Site characterization data gathering requirements in the EC proposed directive are comparable to the types of study called for in the WRI best practices guide. The EC directive, however, calls for site characterization data to be used for a comprehensive, quantitative risk assessment. Not only must all risks be assessed (not just risks to groundwater, as in the EPA UIC proposal) it requires a risk assessment that covers a range of scenarios and addresses both model uncertainty and parameter uncertainty. This intensity of risk assessment goes beyond what is called for in any of the current U.S. CCS regulatory proposals, and would represent a significant expense to implement.

Sequestration is the permitted activity under the EC CCS proposal, contrasting with the current U.S. regulatory framework that permits injection. The EC CCS proposal is primarily performance based—it lays out objectives for site performance and monitoring, as well as requiring plans for corrective measures and post closure actions. It does not, however, specify concrete technical performance standards for such things as reservoir performance (what level of retention constitutes permanent containment) or composition of the CO₂ stream. Unlike the U.S. UIC class VI proposal, that specifies detailed well construction and mechanical integrity testing procedures, the EC proposal is silent on well construction requirements.

Differences between property rights regimes between Europe and the U.S. means that issues of pore space ownership and long-term stewardship play out differently. In Europe, subsurface pore space is typically the property of the national government. The EC proposal envisions a period after injection ceases, where the operator retains responsibility for maintenance, monitoring, reporting

1 Zakkour, P. *Task 2: Discussion Paper, Choices for Regulating CO₂ Capture and Storage in the EU*; European Commission Directorate-General Environment: 04, 2007; p 23 [http://www.ecn.nl/fileadmin/ecn/units/bs/Transitiotechnologieen/Task_2_Choices_for_regulating_CO₂_capture_and_storage_in_the_EU.pdf](http://www.ecn.nl/fileadmin/ecn/units/bs/Transitiotechnologieen/Task_2_Choices_for_regulating_CO2_capture_and_storage_in_the_EU.pdf).

2 European Commission *Proposal for a Directive of the European Parliament and of the Council on the geological storage of carbon dioxide and amending Council Directives 85/337/EEC, 96/61/EC, Directives 2000/60/EC, 2001/80/EC, 2004/35/EC, 2006/12/EC and Regulation (EC) No 1013/2006*; 2008; http://ec.europa.eu/environment/climat/ccs/pdf/com_2008_18.pdf.

3 IPCC, Chapter 5: Carbon Dioxide Transport, Injection and Geological Storage. In *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Prepared by the National Greenhouse Gas Inventories Programme, Eggleston, H. S.; Buendia, L.; Miwa, K.; Ngara, T.; Tanabe, K., Eds. IGES: Japan, 2006; Vol. 2.

and corrective measures, but at the point where the operator can demonstrate that the stored CO₂ will be completely contained for the indefinite future, responsibility for long-term stewardship would be transferred to the national government.⁴ An amendment has been introduced that would hold operators liable for at least 50 years after injection stops. The EC proposal directs member states to ensure that operators make provisions for financial security to cover obligations during operations, and the post injection period. An amendment has been introduced that would require operators to pay into a fund set up in the Member State where the sequestration site is located, to cover the costs of long-term stewardship.

Cross border issues are addressed directly in the EC proposal, and provide useful analogs for approaching potential interstate issues in the U.S. The EC proposal requires member states take the necessary measures to ensure that potential users have fair and open access to CO₂ transport networks and CO₂ sequestration sites; it also requires that they have dispute settlement arrangements in place.⁵ The European Commission would act to coordinate CCS information between member states,⁶ a potential model for the inter-jurisdictional coordination necessary for basin-scale management of GS sites in the U.S.

A.2 Australian State of Victoria Regulatory Proposals

In 2005, the Australian Ministerial Council on Mineral and Petroleum Resources issued a set of guiding principles for geological sequestration of carbon dioxide.⁷ Two pieces of legislation have now been introduced that would implement these guiding principles.

- The Offshore Petroleum Amendment (Greenhouse Gas Sequestration) Bill 2008 is national legislation that would regulate offshore geologic sequestration.
- The Greenhouse Gas Geological Sequestration Bill 2008 is a proposal before the parliament of the southeastern Australian state of Victoria that would regulate onshore geologic sequestration.

Both proposals await action as of October 2008. Policy drivers for CCS in Australia include the facts that Australia has large coal reserves, it is the world's largest coal exporter, and it depends heavily on coal for electrical power generation. Australia is a Kyoto signatory, with a carbon market set to begin in 2010. The national offshore sequestration bill is a series of amendments to the Offshore Petroleum Act 2006 that would establish regulations for the transportation, injection and sequestration of CO₂ under the seabed. The decision was made to base these regulations on Australia's offshore oil and gas regulations because of similarities between petroleum exploration and extraction and geological sequestration, and because it creates a consistent regulatory framework to manage interactions between the two activities.⁸ The bill is silent on the question of long-term liability: this has proved controversial in hearings on the bill conducted by the Australian House and Senate.

On-shore GS is the focus in the U.S., so the rest of this section concentrates on the Victorian state proposal. Victoria has abundant coal, oil and natural gas resources and is pursuing policies to utilize these resources while managing GHG emissions (e.g., Strategic Policy Framework for near Zero Emissions from Latrobe Valley Brown Coal).⁹ The stated purpose of the proposed GS legislation is to facilitate and regulate permanent geologic sequestration of CO₂ as part of Victoria's commitment to GHG reductions. The specific objectives of this bill are to:

- encourage and facilitate GS
- create a fair, orderly, and simple permitting system
- establish legal framework that: minimizes health and environmental impacts; provides appropriate access to information about GS operations; rehabilitates land affected by GS; fairly compensates landowners; and, enforces license provisions
- ensure that GS is conducted in accordance with the principles of sustainable development
- enable the Crown to assume responsibility for long-term stewardship

⁴ EC proposed directive on the geological sequestration of carbon dioxide, Article 18(1)

⁵ Articles 20 and 21

⁶ Article 25

⁷ MCMR Carbon capture and geological storage: Australian regulatory guiding principles; Ministerial Council on Mineral and Petroleum Resources: 2005; p 64 <http://www.ret.gov.au/General/Resources-CCS/Pages/RegulatoryGuidingPrinciplesforCarbonDioxideCaptureandGeologicalStorageCCS.aspx>.

⁸ Senate Standing Committee on Economics, Inquiry into the Offshore Petroleum Amendment (Greenhouse Gas Storage) Bill 2008 & 3 related bills. In 2008.

⁹ Department of Primary Industries A Regulatory Framework for the Long-Term Underground Geological Storage of Carbon Dioxide in Victoria - Discussion Paper. <http://www.dpi.vic.gov.au/DPI/dpinenergy.nsf/childdocs/-3F827E74C37E0836CA25729D00101EB0-866B51F390263BA1CA2572B2001634F9-E3451377DF5BCEEDCA2573D0001A7241?open> (7 April 2008),

This is a distinctly different model than regulation of GS under the UIC in the U.S., where the single objective is protection of USDWs. The Victorian bill offers three types of permits: exploration permits; retention leases; and, injection and monitoring licenses, a system that protects operators' investments in site characterization studies, but allows the government to require that GS resources be put to use.

Before license approval for commercial scale injection, an applicant would need to submit site characterization results, proposed operating conditions, and estimates of available sequestration capacity. The injection and monitoring plan must also include an assessment of potential leakage or migration pathways, the effect of any leakage on public health, the environment or other resources, and the likelihood of leakage, as well as a risk management plan. This bill is less prescriptive than the European plan, in that it does not specify the methods by which the potential effects or likelihood of leakage must be assessed.

The procedure for approval of proposed injection and monitoring plans is somewhat complex. The Minister of the Department of Primary Industries (a natural resources regulator) must be satisfied that the planned project would not present a risk to public health or the environment, but he or she must also provide the Ministers administering the Environment Protection Act 1970 and the Water Act 1989 with the opportunity to comment on whether the proposed GS project presents risk to the environment. If they are of the opinion that the project presents environmental risk, they can make binding recommendations against approval. The approval process also contains a mechanism by which a project cleared of potential health or environmental risks, but which may sterilize other resources, can still win approval by providing compensation and obtaining consent from the affected resource authority holders.

Property rights issues are clearly delineated under this bill. The Australian government owns all underground geological sequestration formations, and retains this right when conferring a GS permit, lease or license (s. 14-15). Compensation is not payable for the value of the underground geological sequestration formation (s. 203). Details on what compensation is payable for (on both private and public lands) is clearly laid out, including payments for easements, surface damages, loss of amenity, and decrease in market value (s. 201, s. 204). Procedures are also laid out to compensate holders of other natural resource authorities if their resources are sterilized by GS operations (s. 48, 104). Access rights and compensation schemes are laid out for geophysical surveys or well installations that are necessary for site characterization, but that fall outside the license area (s. 124-146).

The bill provides that government will assume responsibility for long-term stewardship. After injection ceases, when the operator can demonstrate that the site is behaving predictably and that risks have been reduced to as low as is reasonably practicable, the Minister can consent to the surrender of the injection and monitoring license, at which point the government assumes ownership of the injected CO₂ (s.16). Operators must estimate the cost of long-term monitoring and verification, and pay these costs in annual installments (s. 112); they must also purchase rehabilitation bonds to cover costs of any necessary remedial activities (s. 219-222).

The bill also provides for unit development of geological sequestration formations. The Minister may require holders of GS injection and monitoring licenses within a basin to enter into cooperative arrangements in order to enable more effective injection and monitoring, maximize the sequestration capacity, and minimize the impact on the public (s. 119).

There are several aspects of institutional design worth noting in this bill. First, responsibility for granting permits rests with the natural resource regulator (Department of Primary Industries), but the environmental regulator (EPA) will administer monitoring and verification. Second, concerns over potential conflicts of interest in letting the regulator that has overseen operations decide whether to accept transfer of the site to public ownership are somewhat ameliorated by provisions for an independent panel to consider an application for surrender of authority (site closure) (s. 173).

This proposal is similar to the European proposal in that it is primarily performance based—it lays out objectives for site performance and monitoring, as well as requiring plans for risk management and post injection actions. It does not, however, specify concrete technical performance standards for such things as reservoir performance (what level of retention constitutes permanent containment) or composition of the CO₂ stream. It is entirely silent as to well construction requirements.

Overall, the Victorian legislative proposal is strongly focused on clarifying property rights issues, establishing rules for commercial entry into this new industry, and managing potential interactions between geological sequestration and other natural resources. It leaves tactical details of permitting site operations to be established by agency rulemaking processes.

Appendix B: Current Cap-and-Trade Legislative Proposals

In the 110th Congress, a number of bills in the United States House and Senate addressed the implementation of carbon capture and sequestration technology in the context of a national GHG reduction program. Of the various bills, only the Climate Security Act of 2008 (Lieberman-Warner),¹ was reported by the Senate Committee on Environment and Public Works (EPW) and considered on the Senate floor, where it died when a cloture motion failed. That bill is regarded by some observers as the starting point for the climate debate in the 111th Congress in 2009.

In the interest of brevity, we review the CCS-related provisions of Lieberman-Warner and a “discussion draft” version of another fully articulated economy-wide cap-and-trade bill, which includes CCS provisions to manage U.S. GHG emissions (Dingell-Boucher).² Both bills would establish cap-and-trade programs to limit emissions beginning in 2012 with continuing emissions reductions through 2050. CCS projects would qualify for sequestration credit and bonus allowances under both bills’ cap-and-trade schemes.

Neither bill fully works out the regulatory treatment of CCS, nor explicitly addresses regulatory accounting for a CCS project that experiences later surface leakage, although Dingell-Boucher comes closer than Lieberman-Warner.

B.1 Lieberman-Warner

Point of Regulation: Lieberman-Warner, as originally conceived, set forth two basic regulatory mechanisms to account for and credit sequestered CO₂ depending on the source of the CO₂. Coal is regulated “downstream” at the point of combustion. Coal-fired power plants and other large coal-fired facilities must submit an emission allowance (or offset) for every ton of CO₂ they emit. To the extent the facility captures and sequesters CO₂ produced at the facility, no CO₂ is emitted and no allowance (or offset) submission is necessary for the sequestered CO₂.³ Oil and natural gas, on the other hand, are regulated “upstream”, at the point of refining or processing, rather than at the point of combustion. Facilities that sequester CO₂ from combustion of oil or natural gas are eligible to receive a credit for each ton of carbon they sequester. The credit is equivalent to an emission allowance and equal to the quantity of tonnes of CO₂ sequestered.⁴

Bonus Allowances: Regulated entities are also eligible to receive a bonus allowance to account for the tonnes of CO₂ emissions avoided through capture and geologic sequestration of emissions by a CCS project.⁵ The tonnes avoided, multiplied by that year’s bonus allowance rate and a bonus allowance adjustment factor determines the allowance.⁶ There is a ten-year limit placed on the receipt of these allowances.⁷ The bill also authorizes the EPA to prescribe annual emission performance standards for CO₂ emissions from CCS projects.⁸ Only those projects that meet such standards will be eligible for a bonus allowance.

Regulation of CCS: Finally, the bill amends the Safe Drinking Water Act (SDWA) to add a subsection on CO₂ injection, and it directs the Administrator of the EPA to promulgate regulations establishing standards for permitting commercial-scale underground injection of CO₂ “for purposes of sequestration to address climate change.”⁹ The regulations would require injectors to “monitor and control

1 S. 2191, 110th Cong. (2007), introduced by Senators Lieberman and Warner on Oct. 18, 2007. The bill became S. 3036, which was a complete substitute of S. 2191. References in the text are to the “final” version of the bill that was released by Senate Legislative Counsel and filed for consideration on the Senate floor (June 4, 2008 draft). 110th Cong. (2008). The Senate failed to achieve enough votes to invoke cloture on a motion to proceed following debate, effectively killing it until the next Congress.

2 On October 7, 2008, Reps. John Dingell and Rick Boucher released a discussion draft climate change bill that is intended to stimulate discussion and serve as a basis for legislation that they plan to introduce in 2009 during the 111th Congress [hereinafter Discussion Draft].

3 The version of Lieberman-Warner finally offered in the Senate floor; if read literally, could be interpreted as requiring coal-fired power plants to submit allowances for CO₂ produced by combustion of coal even if the CO₂ is sequestered and no emission occurs. This is an apparent drafting error.

4 S. 3036 § 202(f).

5 *Id.* §§ 202(f); 1013 (a).

6 *Id.* § 1013(a).

7 *Id.* § 1014.

8 *Id.* § 1012(c).

9 *Id.* § 1021(a)(3). In July 2008, the EPA issued a Notice of Proposed Rulemaking to amend its regulations for underground injection wells, under its SDWA authority. The proposed rule creates a new class of injection wells, Class VI, which are used for geologic sequestration of CO₂ beneath the lowermost formation containing an underground source of drinking water. The preamble to the rule notes the importance of CCS project deployment as addressed by the Lieberman-Warner bill and the Bingaman-Specter bills. The preamble also notes that the EPA’s authority under the rule is limited to protecting sources of drinking water and does not include the regulation of CO₂ under the Clean Air Act. For that matter, the EPA’s proposal would not address accounting or certification for greenhouse gas reductions because the SDWA does not provide such authority. *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO₂) and Geologic Sequestration (GS) Wells*, 73 FR 43492 (July 25, 2008). The Lieberman-Warner language would remove this barrier.

the long-term storage of carbon dioxide; to avoid, to the maximum extent practicable, and quantify any release of carbon dioxide into the atmosphere...” in addition to protecting underground sources of drinking water, human health, and the environment.¹⁰ This section also authorizes the EPA to promulgate regulations addressing the financial responsibility for CCS site monitoring.¹¹

Liability for Surface Leakage: As written, the bill does not provide EPA with explicit authority to address surface leakage from CCS projects under the regulatory provisions of the cap-and-trade program. It allows a credit for sequestered CO₂ emissions calculated on the basis of tonnes sequestered in a particular calendar year.¹² While this credit is subject to verification and adjustment,¹³ the legislation does not specify whether adjustment authority extends beyond the year of injection.¹⁴ For this reason, it is unclear whether the SDWA amendments could provide EPA with authority to adjust sequestration credits to address later surface leakage.¹⁵

B.2 Dingell-Boucher

Dingell-Boucher, like Lieberman-Warner, would address the capture and sequestration of CO₂ as part of a larger economy-wide cap-and-trade program. However, it takes a different approach. Dingell-Boucher would regulate both coal and large-natural gas-fired sources of electricity downstream, at the point of combustion. Entities that engage in CCS projects are eligible for bonus allowance credits to provide incentives for the sequestration of CO₂. However, regulatory accounting for such credits is addressed more directly than in Lieberman-Warner.

Point of Regulation: Electricity sources (electric generators) and stationary industrial sources are regulated downstream and must hold an emission allowance for each ton of CO₂ equivalent (CO₂e) it emitted in the previous calendar year from the combustion of fossil fuels.¹⁶ Emissions from the combustion of petroleum-based liquid fuels are regulated upstream at the point of production or importation.¹⁷ Producers and importers of such fuels must hold allowances to cover the downstream CO₂ emissions of the fuel they produce. An entity regulated downstream need not hold emission allowances for those tons of CO₂ that it sequesters, as opposed to emits. Entities regulated upstream (including petroleum-fuel producers and importers and local distribution companies) must submit allowances regardless of whether the tons covered are sequestered further downstream.¹⁸

Bonus Allowances: To account for the high cost that may be associated with CCS, and to encourage the use of CCS technology, the proposed legislation also creates a bonus allowance mechanism for certain covered sources.¹⁹ Electricity and industrial sources (including coal, natural gas, and petroleum-fuel fired sources) that sequester their CO₂ emissions in eligible CCS projects may be eligible to receive a bonus allowance.²⁰ This includes petroleum refineries, which the proposal includes as industrial sources.²¹ No such bonus allowance exists for petroleum-based fuel producers and importers, to the extent that they are regulated upstream.²²

10 S. 3036 § 1021(a)(3). Read broadly, this provision could address regulatory accounting, although it is not explicit.

11 *Id.* § 1021(a).

12 *Id.* §§ 202(f); 1013(a)(1).

13 *Id.* §§ 1013(a)(2); 1013(b)(1).

14 As noted above, one reading of the allowance submission requirements for coal-fired plants requires the submission of allowances even if their CO₂ is sequestered. Were this the intended result, no adjustment for subsequent leakage of sequestered CO₂ would be necessary since no credit was originally given.

15 The bill also addresses safety risks associated with leakages. The bill directs the Secretary of Interior, acting through the Director of the United States Geological Survey, to assess the nation's capacity for CO₂ sequestration, including the risk associated with potential storage formations. *Id.* § 1022(b)(5). A risk includes “any risk posed by a geomechanical, geochemical, hydrogeological, structural, or engineering hazard.” *Id.* § 1022(a)(4). Currently, the EPA does not believe that the SDWA provides it with authority to regulate the atmosphere, only environmental and safety concerns as they pertain to water.

16 Discussion Draft §§ 712(a)(1), (5). The holding requirement excludes emissions resulting from petroleum-based or coal-based liquid fuels, biomass, petroleum coke, or emissions resulting from certain fluorinated gasses. For some industrial sectors, an industrial stationary source is not regulated as a covered entity unless it emits 25,000 or more tons of CO₂e, but this requirement is not universal. *See id.* §§ 700(8)(B)(E)-(G). The number of allowances available to such sources decreases steadily between calendar years 2013 and 2050, § 711(e), but the level of their distribution would vary based on four allocation options provided in the draft. *See id.* § 721.

17 *Id.* § 712(a)(2). Stationary sources that produce or import petroleum-based or coal-based liquid fuel are required to hold an allowance for each ton of CO₂e that will be emitted from that fuel's combustion or oxidation during the previous calendar year, if the combustion or oxidation of fuel from that facility will exceed 25,000 tons of CO₂e.

18 *See id.* §§ 712(a)(2) and (a)(7). Fuel producers and importers and local distribution companies, each regulated upstream, must submit allowances “assuming no capture and sequestration of any greenhouse gas emissions.”

19 The legislation appears to exclude fuel producers and importers from any CCS-related bonus allowance mechanism.

20 *Id.* § 724. The proposed legislation does not require electricity or industrial sources to hold emission allowances for coal-based or petroleum-based liquid fuels since those allowances are held upstream by the producer or importer. However, the proposed legislation does not limit electricity or industrial sources from obtaining bonus allowances for the sequestration of their resulting emissions.

21 Discussion Draft § 700(20). Petroleum refineries are members of the manufacturing section as defined in North American Industrial Classification System codes 32.

22 *See id.* § 724. The proposed legislation creates CCS incentives for electricity and industrial sources in the form of a Sequestration Bonus Allowance Account. Petroleum-based and coal-based fuel importers are categorically excluded from electricity sources. Further, they would not be considered industrial sources. The credits provided to industrial sources must be used to offset the CO₂ emissions produced at that source, not further downstream. *Id.* § 724(b)(3)(B). This reflects the difficulty associated with crediting upstream sources for future downstream emissions.

Assuming sequestration occurs in a certified CCS project site, certain covered entities may be eligible to receive CCS bonus allowances.²³ The eligibility and performance standard requirements will depend on whether the emission source is electricity or industrial. The draft bill provides an equation to calculate the allowance distribution amount for an eligible electricity source, identified in Chapter 10 of the report.²⁴ The draft defines “bonus allowance values,” which start at \$90 per ton for early CCS projects, and eventually drop to \$50 per ton.²⁵ A project is eligible for bonus allowances for the first ten years only.²⁶

Bonus allowances for new electricity projects would be cut off once cumulative generating capacity using CCS exceeded 60 GW, or if the bonus account would be oversubscribed.²⁷ An electricity source must also meet performance standards²⁸ and eligibility criteria.²⁹

For industrial sources, the draft bill does not provide a similar equation to calculate bonus allowance distribution; rather, they are calculated under EPA regulations.³⁰ Eligibility requirements are also prescribed by regulators. Industrial CCS projects would need to be in compliance with allowance regulations, sequester at least 85 percent of the associated industrial source’s total CO₂ emissions, and not receive other Federal or State financial incentives.³¹ The level of financial assistance for such projects, in the form of bonus allowances, would be limited to what is necessary to permit recovery of reasonable incremental capital and operating costs, and would not subsidize enhanced oil recovery operations.³² These projects would only qualify for the first 5 years of operation.³³

Liability for Leakage: Dingell-Boucher, by treating a geologic sequestration site as a “covered entity,”³⁴ creates an apparent mechanism to account for CO₂ leakage following its sequestration. As a covered entity, a CCS project would be required to hold an emission allowance for each metric ton of CO₂ it emitted in the previous calendar year.³⁵ For “certified geologic sequestration sites,”³⁶ Dingell-Boucher directs the Administrator of the EPA to prescribe regulations that establish a certification program for their regulation. Among the requirements, the EPA must create monitoring and reporting requirements for certified project sites.³⁷ The mechanics of calculating and implementing a repayment scheme to account for leakage in later years are unclear for those sites that are not certified.

Regulatory Requirement for CCS: Dingell-Boucher envisions a growing role for CCS in its GHG regulatory scheme. CCS would be a required component of any new electric generating unit (EGU) with a rated capacity of 25 MW or more on an annual basis that comes on line by January 1, 2025, or if later, the date 4 years after it commences operation.³⁸ The Administrator would be responsible for promulgating regulations implementing this CCS requirement.³⁹

23 *Id.* § 724. Dingell-Boucher determines the availability of bonus allowances by the emissions’ source. Seventy-five percent of the allowances available for CCS would be allotted to electricity sources, *id.* § 724(a)(1), which would include both natural-gas and coal-fired power plants. *Id.* § 712(a)(1). Industrial sources, again including emissions that result from the combustion of coal and natural gas, but including other causes of GHGs, *id.* § 712(a)(6), would be allotted the remaining 25 percent of available bonus allowances. *Id.* § 724(b)(1).

24 *Id.* § 724(a)(7)(A). Allocation to industrial sources is pursuant to EPA rules. *Id.* § 724(b)(2).

25 *Id.* §§ (a)(7)(B)(i)-(iii).

26 *Id.* § 724(a)(11)(A). There is an incentive to begin a CCS project sooner rather than later because the bills commits to providing bonus allowances for 10 years, but will not allocate allowances to new projects if it would compromise the 10 years of guaranteed allowances to those projects already in progress. *Id.* § 724(a)(11)(B).

27 *Id.* §§ 724(a)(10)(B), 724(a)(11)(B).

28 Those existing units that commence operation of CCS capture equipment before Jan. 1, 2016 must treat at least 100 MW equivalent flue gas stream and be designed to capture and sequester at least 85% of the CO₂ from the treated flue gas stream. *Id.* § 724(a)(5)(A). Any existing units that commence operation of CCS equipment after Jan. 1, 2016 must achieve an annual emission rate of not more than 1200 lbs CO₂/MWhr (~ 50% CO₂ capture). *Id.* § 724(a)(5)(B). New entrants (utility unit that begins operations after the date of enactment) must achieve an annual emission rate of not more than 500 lbs of CO₂/MWhr (~70% to 75% CO₂ capture). *Id.* § 724(a)(5)(C). Performance standards would be adjusted for coal type. *Id.* § 724(a)(6).

29 *Id.* § 724(a)(4). The project must have commenced CCS operations between Jan. 1, 2008 and Dec. 31, 2035, must have a rated capacity of 250 MW or more, and cannot receive other Federal or State financial incentives including loans, loan guarantees, grants or tax credits. Sequestration of CO₂ must also occur in a certified geologic storage site. *Id.* § 724(a)(4)(B).

30 *Id.* § 724(b)(2).

31 *Id.* § 724(b)(3).

32 *Id.* § 724(b)(4)(A).

33 *Id.* § 724(b)(5). Preference is also given to early projects. EPA cannot allocate allowances to new projects if it would compromise the 5 years of guaranteed allowances to those projects already in progress. *Id.* § 724(b)(6)(B).

34 *Id.* § 700(8). Covered entities also include electricity sources, fuel producers and importers, fluorinated gas producers and importers, geological sequestration sites, industrial stationary sources, and local distribution companies.

35 *Id.* § 721(a)(4)(A)(i). Emission allowances are a limited authorization to emit 1 ton of CO₂e of a GHG as part of the cap-and-trade program. *Id.* § 700(12). The discussion draft provides four options, A, B, C, and D, for allocating the bonus allowance amounts under sec. 721. Based on the option letter discussed and vintage calendar year addressed, the percentage allocation to CCS projects ranges from 2 percent of the emission allowances provided for that calendar year to a high of 5 percent of that year’s emission allowance pool.

36 *Id.* §§ 724(a)(4)(B), 724(b)(3)(B). The Administrator is directed to consider overlap between CCS and Safe Drinking Water Act regulations.

37 *Id.* § 832.

38 *Id.* § 812. A new EGU would be required to capture and geologically sequester at least 60 percent of its total CO₂ emissions if it derives at least 50 percent of its annual fuel input from coal, petroleum coke, or combination thereof. An extension of up to 18 months is available only if the EGU can demonstrate to the EPA’s satisfaction that it is unable to meet the standard due to technical infeasibility.

39 *Id.* § 812(c). There is no direct discussion of leakage penalties in the draft proposal.

