Carbon Capture and Storage

An Assessment

A V600 Capstone Course

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Executive Summary

This report examines the role of carbon capture and storage (CCS) technologies as part of a portfolio of carbon management strategies in the United States over the next 50 years. Based on the findings from the Spring 2009 V600 Capstone on *The Future of Electricity*, worldwide electricity consumption is projected to increase 350% from its current level over the next 50 years (Adamec et al., 2009). Alternative energy sources are projected to represent a greater percentage of electricity generation in the future. However, fossil fuels such as coal and natural gas are abundant resources that are expected to be extensively used in the next 50 years. Carbon management strategies must consider mitigation methods to combat emissions CO_2 from these fossil fuels.

This report finds that CCS technologies raise the levelized cost of electricity in coal and natural gas generating facilities by 1.3¢ to 2.2¢ per kWh (between 30% and 60%) depending on the capture technology used and the type of generating facility. Coal fired and natural gas facilities with carbon capture and storage were found to be more costly than nuclear power but were cheaper than renewable electricity sources such as wind, solar thermal, and photovoltaic.

If reducing atmospheric carbon dioxide emissions from the electric power sector becomes a national priority, we recommend policies that expedite CCS deployment. Federal funding for research, development and deployment will be crucial to implement CCS on a commercial scale. Our cost analysis demonstrates that fossil fuel technologies with CCS are cost effective approaches to reduce CO_2 emissions in the near- and medium-term future. We also find that legal considerations and public perception will require attention if CCS is to be successfully deployed. However, health and environmental effects, while necessary to acknowledge, were not found to pose a significant barrier to CCS deployment.

Key Findings

IGCC technology has the highest cost of electricity (COE) without carbon capture, but has the lowest incremental cost for adding capture. The COE for oxyfuel capture units becomes more cost-competitive with the addition of capture to fossil fuel units. With capture technology, natural gas combined cycles (NGCC) facilities and oxyfuel ultracritical process facilities emerge as the least-cost fossil fuel technologies.

This report recommends government cost-sharing of a portfolio of pilot projects to develop nascent carbon capture technologies. Capture technologies will benefit from learning-by-doing with improved performance and lower costs. Initial commercial-scale testing of CCS will improve the understanding of associated risks and costs necessary to develop long-term CCS policy.

Additionally, this report finds that IGCC and oxy-fuel plants have yet to achieve commercial-scale application. Our analysis indicates they are more cost-effective applications for CCS than conventional coal. Therefore the promotion of such advanced coal technologies at commercial-scale is advisable. Current domestic projects capture a fraction of the carbon necessary and thus need to be scaled-up to 80-90% capture rates.

Storage risks need to be investigated through pilot projects implementing actual geologic injection. The risks associated with increasing subsurface pressure from injecting massive amounts of CO_2 underground, including induced seismic activity and groundwater displacement, are not adequately understood by simulation and need further testing in the field.

The selection criteria and financing of the recently chosen Department of Energy (DOE) projects is an appropriate first step. However, the magnitude of expenditure and number of projects funded would need to increase modestly to be consistent with suggestions made by energy experts (NRC, 2008; Kuuskraa, 2007).

Course Information

A V600 capstone course at the Indiana University School of Public and Environmental Affairs (SPEA) is an opportunity for master's students to apply knowledge acquired from the specialized program concentrations in one comprehensive report. Capstone assignments require students to analyze technological, environmental, legal, social, and economic implications of the topic and recommend policies that incorporate them. Thus, capstone courses are designed to challenge students to comprehensively research a topic that they may have little knowledge or experience with, as well as make sound recommendations based on their analysis. The purpose of this 2010 V600 Capstone course is to analyze the role of carbon capture and storage technology as part of a carbon management portfolio over the next 50 years.

Key Acronym List and Definitions

BkWh-Billion Kilowatt Hour
Btu-British Thermal Units
CCS-Carbon Capture and Storage
CER-Certified Emission Reduction
CO_2-Carbon Dioxide
DOE-Department of Energy
EIA- Energy Information Administration
ECBM-Enhanced Coal-Bed Methane
EOR – Enhanced Oil Recovery
EPA-US Environmental Protection Agency
EPACT-Energy Policy ACT
EUA-European Union Allowance
EUETS-European Union Emissions Trading Scheme
GDP-Gross Domestic Product
GHG-Green House Gas
GW-Gigawatts
Gt – Gigatons
HVAC- Heating, Ventilating and Air-Conditioning
HVDC-High Voltage Direct Current
IDM- Industrial Demand Module
IEA-International Energy Agency
IGCC-Integrated Gasification Combined Cycle
IPCC-Intergovernmental Panel on Climate Change
ITC-Investment Tax Credits
Km-Kilometers
KW-Kilowatts
kWe-Kilowatt Electricity
kWh- Kilowatt Hours
MIT-Massachusetts Institute of Technology
MMBtu-Million British Thermal Units
MMV-mitigation, monitoring and verification
MPa – MegaPascals, Pressure
MW-Megawatts
NAICS- North American Industry Classification System
NEMS- National Energy Modeling System
NETL-National Energy Technology Laboratory
NGCC-Natural Gas with Combined-Cycle
NIMBY- Not In My Backyard
NO_x-Nitrogen Oxides
OECD- Organization for Economic Co-operation and Development
PC-Pulverized Coal
PM-Particulate Matter
PPM- Parts per million
PPP-Purchasing Power Parity
PTC-Production Tax Credits
PV-Photovoltaic
R and D-Research and Development
RCRA- Resource Conservation and Recovery Act
RCSP-Regional Carbon Sequestration Partnerships
RGGI-Regional Greenhouse Gas Initiative
UNEP-United Nations Environment Programme
SDWA-Safe Drinking Water Act
SECARB-Southeast Regional Carbon Sequestration Partnership
SO_2-Sulfur dioxide
TPC- Total Plant Cost
UIC- Underground Injection Control Program
UNFCCC- United Nations Framework Convention on Climate Change
USDW- Underground Sources of Drinking Water

Chapter I: Introduction and Background

Introduction

According to the U.S. Environmental Protection Agency (EPA), the United States emitted 5.9 billion metric tons of CO_2 into the atmosphere in 2008. Of that total, 2.3 billion metric tons can be attributed to burning fossil fuels for electricity generation, representing approximately 40% of the total U.S. carbon dioxide emissions in that year (EPA, 2010). Given projections on the increasing use of coal to generate electricity in the future, ways must be found to reduce atmospheric emissions of carbon dioxide while retaining the ability to harness the massive coal resources available in the United States and elsewhere in the world. The use of carbon capture and storage (CCS) systems on fossil-fuel electricity generating stations is one option that would allow the United States, and other countries, to continue coal use while reducing atmospheric emissions.[1]

Before large-scale deployment of carbon capture and storage (CCS) can occur, many challenges surrounding the use of such technology must be addressed. These challenges include cost-competitiveness, legal and regulatory obstacles, environmental and public health risks, and social resistance. The costs of CCS relative to alternative low carbon energy technologies will largely determine the extent of its deployment. Additionally, the deployment of CCS may disproportionately impact a variety of stakeholders in numerous ways. As a result, governments must carefully create policies that address all of these issues.

This report examines the possible roles for CCS, its impacts on various stakeholders and corresponding regulations and policies. The goal is to advise policymakers in the United States how CCS could best be incorporated into a carbon management strategy for the short, medium, and long term and serve as an example for other countries worldwide. The findings presented in this report will be of interest to CCS stakeholders, including the electric power industry, investors, insurance companies, public health and environmental organizations, regulatory agencies, local governments, and residents of communities with proposed CCS sites.

Background

Current and Future Fossil Fuel Use

Although the uses of alternative energy technologies are increasing, projected fossil-fuel use is not projected to decline in the near future. Specifically, the Energy Information Administration (EIA) predicts fossil fuel consumption will still account for 78% of domestic energy consumption in 2035. While this is down from 84% in 2008, the actual quantity of fossil fuels consumed is predicted to grow 14% overall due to increased energy demands (EIA, 2009).

EIA estimates coal and natural gas consumption to increase by 2035, with petroleum use staying relatively constant. This rise is due to increasing petroleum costs, increases in the number of coal-based power plants, and the expanding use of coal-to-liquid (CTL)

[1] The terms "sequestration" and "storage" are used interchangeably in the literature. We have chosen to use the term storage in this report.

technologies. Natural gas consumption is expected to increase 4% by 2035. The lower-cost potential for natural gas, when compared to petroleum prices, is the main driving force for growth in the long term. Consumption of liquid fuels, including both petroleum and biofuels, is predicted to grow 9% by 2035. Biofuels will account for the majority of this growth while petroleum use will remain constant (EIA, 2009). Excluding hydroelectricity, renewable energy production is predicted to grow 2.8% annually. EIA also predicts that international fossil-fuel energy consumption will increase 42% by 2030. Coal consumption will increase 47%, while renewable energy will increase 48% by 2030 (EIA, 2006).

Current and Future CCS Technology

Currently, there are no large-scale carbon capture projects operating in the United States. There are smaller projects capturing carbon in industrial processes, but carbon capture has not been applied to large-scale electricity generating plants (plants greater than 400 MW), primarily due to the absence of policies mandating reductions in carbon emissions. Some companies, however, are planning for regulations which will limit CO_2 emissions. In Edwardsport, Indiana, Duke Energy is constructing a 630 megawatt integrated gasification combined cycle (IGCC) coal-fired power plant. Once completed, the Edwardsport IGCC plant will be the third of its kind in the United States and the largest in terms of generation capacity. The plant offers state-of-the-art pollution control equipment and drastically reduces air pollutants through its gasification process. Also, this type of plant is ideal for the capture of carbon dioxide. In 2009, Duke Energy sought approval from the Indiana Utility Regulatory Commission to begin site surveys for potential geologic storage sites. The IGCC plant has an estimated completion date of 2012 and an estimated cost of three billion dollars.

While it is important to consider technological changes in newly constructed fossil fuel plants, it is also very important to examine existing plants. According to the EIA, there are 390 coal plants and 748 natural gas plants currently operating in the United States.[2] The Department of Energy's National Energy Technology Laboratory (NETL) has been leading research efforts into retrofitting existing plants for carbon capture and storage. This research has produced promising results on the future of retrofitting plants which could significantly reduce the costs of implementation. One of the primary technological challenges to large-scale CCS implementation is finding low cost methods for the capture of CO_2.

[2] These plants have a minimum summer capacity of 100 megawatts (EIA, 2010).

Chapter II: Carbon Capture

Carbon Capture Technologies

The carbon capture and storage process involves three separate, yet integrated processes of capture, transport, and storage. The capture stage of the process involves the physical separation of carbon dioxide from its source. The captured carbon dioxide is then compressed to produce a concentrated fluid to be transported and stored. The following section outlines various technologies for capture of carbon dioxide from electricity generating plants.

Of the stages involved in the carbon capture and storage process, the capture phase is the highest cost component representing as much as of 80% of the total cost (Folger, 2009). Capture costs are a combination of initial capital investment, operation and maintenance, and reductions in overall electricity output. Commercially available capture technologies, as well as those under development, require additional amounts of electricity to operate. Most also require significant amounts of heat and water for various chemical and other operating processes, thus adding to the operating costs.

Carbon capture technology is still in an early phase of development and has yet to be demonstrated on a large scale. Much of what has been done is preliminary research and smaller demonstration projects. While this early research has yielded valuable information on capture technologies, many questions remain regarding the costs associated with this technology.

Post-Combustion Capture Systems

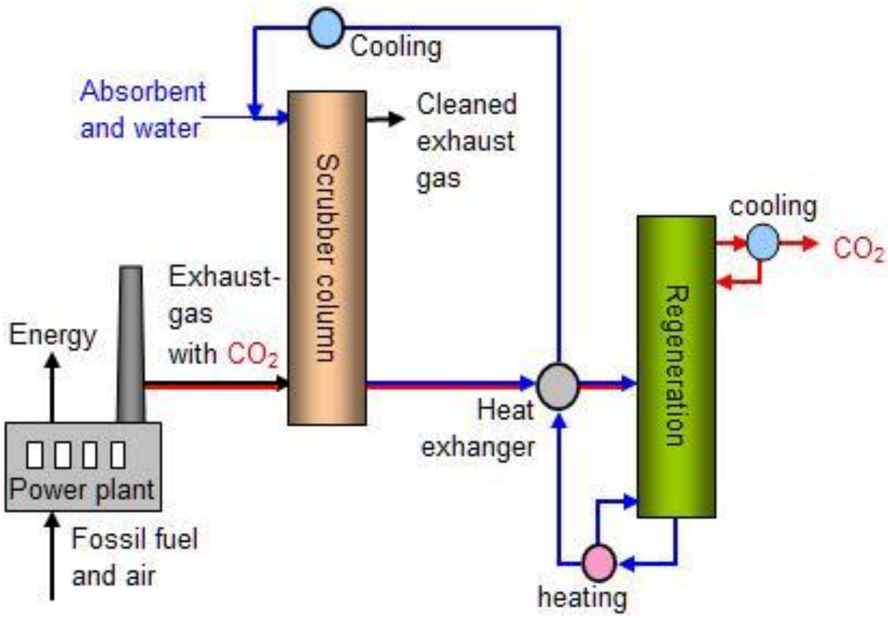
Post-combustion capture of CO_2 is the separation of carbon dioxide from the flue gas emission stream of a pulverized coal power plant. The separation can be done with solvents, membranes, absorbents, or cryogenic methods (Baker, 2009). The more fully developed technologies are discussed below. These technologies are applicable to the majority of existing plants through retrofitting options (Figueroa, 2008). A high concentration of CO_2 in the flue gas stream of approximately 15% aids the capture process (IEA, 2006). While several technologies are commercially available to capture CO_2 in this manner, no economic incentives or legal requirements exist to compel plants to implement such systems.

There are some significant barriers to the use of post-combustion capture. One problem is that the flue gas is at atmospheric pressure when it exits the stack; therefore has a very low thermodynamic driving force (Figueroa, 2008). This low pressure CO_2 requires considerable compression for storage. Compression occurs directly after capture and can represent a substantial portion of the cost of the storage process. Another barrier to the widespread use of capture technology is the necessity to scale-up from demonstration phase facilities to commercial power plants.

Amine-based Wet Scrubbing

Amines are organic compounds that react with CO_2 to create water-soluble compounds. Because CO_2 is an acidic gas, alkaline solvents such as monoethanolamine (MEA) form chemical bonds with CO_2 and can absorb it from a flue gas stream exiting the plant in an absorption tower. One major advantage is this absorption process offers high capture efficiency. The absorbed CO_2 solution must then be heated to a higher temperature to strip the amine solution from the CO_2. The amine is then recycled (a process called regeneration), and the highly concentrated CO_2 is compressed for transport and storage. The energy required for this process is attributed to the steam used to regenerate the amine solution (MIT, 2007). Further energy is required to compress the concentrated CO_2. The following diagram shows the amine-based scrubbing system.

Figure 1: Diagram of an Amine-Based Wet-Scrubbing System



Bellona, 2007

Amine scrubbing is currently the only technology for post-combustion carbon capture that is commercially available and fully developed for use. The most widely understood and used amine system involves monoethanolamine (MEA). While amine-based scrubbing systems may separate CO_2 from the flue gas streams of conventional coal plants, they are expensive and require significant amounts of energy. These systems also require large amounts of water to operate and can double overall water requirements. Furthermore, contaminants typically found in flue gases such as sulfur dioxide, nitrogen oxide, hydrocarbons, and particulate matter necessitate removal prior to capture as they may inhibit solvents' ability to absorb CO_2 (Anderson and Newell, 2003). The contaminants also pose other concerns in that they can cause impurities in the CO_2 stream to be subsequently stored.

Although amine-based scrubbing systems have been in existence since the 1930s, they have never been deployed on the scale required for a commercial power plant. Cost for implementation is in three primary areas: initial capital investment, operation and maintenance, and reduction in net plant output. The reductions in plant output are attributed to the level of CO_2 captured. For example, a 2007 National Energy Technology Laboratory (NETL) study revealed reductions between 10-30% of net plant output with systems that captured between 30-90% of CO_2 (Ramezan et al., 2007). Table 1 offers a breakdown of the costs associated with amine capture in 2001 and 2006.

Table 1: Costs of CO_2 Capture with MEA Systems

Year of design	2001	2006
MEA (weight percent)	20	30
Power used (MWh/ton)	0.51	0.37
@ $80/MWh ($/ton CO_2 removed)	41	29
Capital cost ($/ton CO_2 removed per year)	186	106
@16%/year ($/ton CO_2 removed)	30	17
Operating and maintenance cost ($/ton CO_2 removed)	6	6
Total cost ($/ton CO_2 removed)	77	52
Net CO_2 removal with power replaced by gas (%)	72	74

U.S. DOE/NETL, 2007b

Ionic Liquids

Ionic liquids are currently being evaluated as possible advanced solvents and to determine their chemical characteristics as they relate to the process of carbon capture. The benefits of using ionic liquids are possible reductions in cost through developing a process with higher CO_2 loading in the circulating liquid and lower heat requirements for regeneration (U.S. DOE/NETL, 2008). As ionic liquids are currently in the research and development phase, reliable cost estimates are not yet available. However, current research of ionic liquids demonstrates promise as an advanced solvent for CO_2 in the near future.

Carbonates

The University of Texas at Austin has recently developed a carbonate-based system for CO_2 separation. This system is based on a soluble carbonate reacting with CO_2 to form bicarbonate. When heated, the CO_2 is released and the bicarbonate reverts to its previous state (Figueroa, 2008). These types of systems, like ionic liquids, require less heating energy for regeneration. These systems also take advantage of a low heat of absorption and are also tolerant of sulfur dioxide, unlike current MEA systems (U.S. DOE/NETL, 2010a). Carbonate-based systems, like ionic liquids, are in developmental stages, therefore reliable cost estimates are not available at the time. Given initial research, however, these systems show the potential to reduce associated energy costs, particularly when compared with traditional MEA systems.

Metal Organic Frameworks

Metal organic frameworks are hybrid organic/inorganic structures made up of metal hubs linked together with struts of organic compounds to maximize surface area (U.S. DOE/NETL, 2008b). The structures have specifically sized cavities that have very high adsorption rates for CO_2. High storage capacity is possible and the heat required for recovery of the adsorbed CO_2 is low (Figueroa, 2008). Challenges for the use of metal organic frameworks as a CO_2 capture technology are problems of moisture and contaminants in the flue gas stream affecting adsorption (U.S. DOE/NETL, 2010a). Substantial research is underway to overcome these challenges.

Amine-based Dry Scrubbing

In an attempt to overcome the problems associated with large amounts of water needed for wet scrubbing amine systems, researchers are exploring the use of solids to react with CO_2 (Gray, 2005). These solids, mostly amine based, react with CO_2 to form stable compounds under one set of operating conditions and be regenerated in completely different conditions to form the same compounds (Figueroa, 2008). Currently, pilot scale tests are being conducted on a small number of these systems. The goal is to create a solid sorbent that will have a lower energy penalty than MEA systems.

Physical Solvents

Physical solvents are used in CO_2 capture due to their ability to selectively absorb carbon without a chemical reaction. The amount of carbon absorbed depends on the solvent being used, the pressure of the CO_2 gas in the stream, and the temperature (Figueroa et al., 2006).

Physical solvents have proven to be reliable with solvents, such as Selexol and Rectisol, having been used for SO_2 removal for over 30 years. Previously, the captured CO_2 was vented into the atmosphere while the captured SO_2 was scrubbed out of the stream. These processes are efficient in capturing CO_2, but are energy intensive due to the heat transfer involved. In order for these solvents to work, the pre-combusted pressurized stream of syngas must be lowered from a temperature of 500°F to 100°F or less. This lowers an IGCC plant's net efficiency by 3-8% (Ciferno, 2010).

Although using physical solvents for capture is a tested and ready-to-use system, it is still expensive and capital intensive. A new IGCC plant with no CO_2 capture has a total approximate plant cost (TPC) of $1,900/kWe, depending on the gasification system used. A new plant with CO_2 capture has an approximate TPC of $2,500/kWe. This raises the cost of electricity by an average of 37%, with an avoided cost of carbon at $43/ton for IGCC plants utilizing Selexol solvents (U.S. DOE/NETL, 2009a).

Permeable Membranes

Researchers are also examining the possible use of membranes to capture CO_2 from flue gas streams. These systems use permeable or semi-permeable materials that allow for the selective transport and separation of CO_2 from flue gas (Ciferno, 2009). These systems have demonstrated their most effective use in high-pressure applications, but have shown promise in post-combustion situations as well. In January 2010, the Cholla Power Plant in Holbrook, Arizona began testing a pilot membrane system using a series of inorganic membranes.

Membrane systems have many advantages. They would reduce costs by avoiding the expensive absorber system required with amine-based systems (U.S. DOE/NETL, 2008c).

The systems also involve no chemical reactions and no moving parts (U.S. DOE/NETL, 2010a). However, membrane capture systems are still in the early phases of development and will require more research prior to use on a large scale.

Polymer-based Membranes

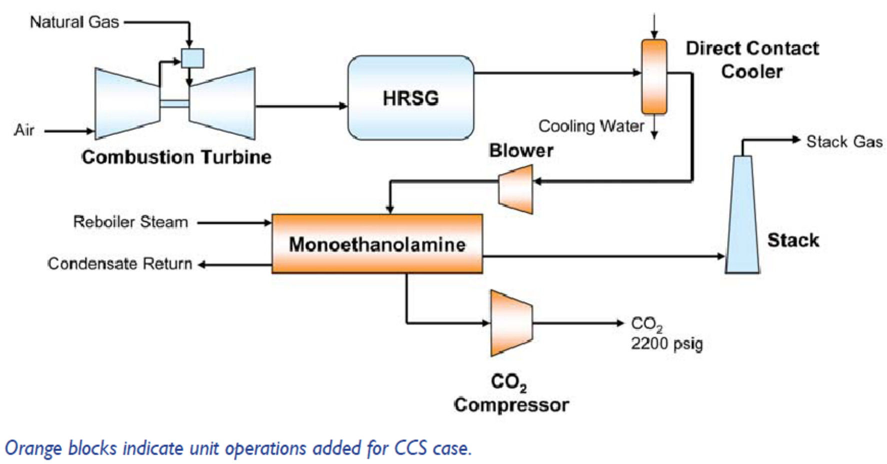
Polymer-based membranes are under research for the absorption of CO_2 from syngas streams. Membranes are less energy intensive than other types of capture, they require no temperature or pressure modifications, and they are typically low-maintenance operations (Figueroa et al., 2006). Commercially available membrane technologies are not stable in the harsh environments of IGCC plants. They are susceptible to chemical degradation by the process steam, a problem exacerbated by the plant's high temperatures (U.S. DOE/NETL, 2008c).

One membrane under development by NETL has demonstrated long-term hydrothermal stability, sulfur tolerance, and overall durability in a simulated industrial coal-derived syngas environment (Figueroa et al., 2006). Research and development of this type of membrane is funded by a $4 million grant from the Department of Energy as a non-DOE investment of $1.5 million (U.S. DOE/NETL, 2010a). This technology has been used in post-combustion capture with polymer-based and ionic liquid membranes, but it faces setbacks for use as a pre-combustion technology due to the large differences in environmental temperature and pressure. NETL has set a goal of producing a commercial-ready version of these membranes by 2012. These membranes will have a 90% capture rate with a parasitic power loss of less than 10% (Ciferno, 2010).

Natural Gas Combined Cycle (NGCC) Systems

In a natural gas combined cycle (NGCC) system, natural gas is first burned in a combustion turbine. The combined cycle process begins when additional energy is generated in the heat recovery steam generator. Following this process, an amine scrubbing system is used to capture the CO_2 prior to transport and storage. Figure 2 depicts the basic process.

Figure 2: NGCC Process with Carbon Capture



Nitrogen oxides control: dry low-NOx burner + selective catalytic reduction to maintain 2.5 ppmvd @ 15% oxygen

Carbon dioxide control: Monoethanolamine system for 90% removal

Steam conditions: 2,400 psig/1,050°F/950°F

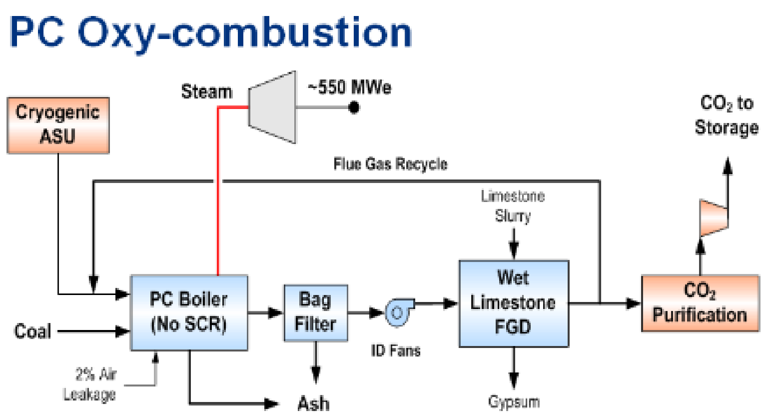
U.S. DOE/NETL, 2007e

Oxy-Combustion Systems

Oxy-combustion occurs when pulverized coal is combusted in an environment of pure oxygen diluted with recycled flue gas. Conventional coal combustion requires a combustion environment that is 80% nitrogen. Oxy-combustion produces flue gas composed primarily of CO_2 and H_2O. A concentrated stream of CO_2 is then produced by condensing and removing the water in the exhaust stream (U.S. DOE/NETL, 2008c).

Oxy-combustion has much potential for a step-change reduction in CO_2 separation and capture costs, as virtually all of the exhaust effluents can be captured and sequestered. Figure 3 depicts the oxy-combustion process (U.S. DOE/NETL, 2008c).

Figure 3: U.S. Department of Energy CO_2 Capture Program for Oxy-Combustion Processes



Ciferno, 2010

A 60 to70% reduction in NO_x exists in air-fired combustion when using flue gas recycling. There is also a reduction in the mercury emissions that must normally be removed from the flue gas. Other oxy-combustion advantages include direct application to new coal-fired power plants, conventional equipment used in the power generation industry, and proven process principles such as air separation and flue gas recycling (U.S. DOE/NETL, 2008c).

The oxygen-rich combustion environment creates temperatures that are much higher than for normal combustion, requiring a change in existing boiler and turbine materials. Increasing flue gas may lower combustion temperatures, but this increases parasitic energy loss and raises the overall cost of electricity. Air infiltration in the boiler dilutes the flue gas stream, which in turn increases the energy needed to filter the flue gas prior to mixing with oxygen for combustion. This technology has high capital costs due to the need for expensive air separation units (U.S. DOE/NETL, 2007c).

Despite the high initial capital costs, oxy-combustion has a potential cost of \$37/ton CO_2 avoided, making it one of the most inexpensive options for new and retrofitted coal-fired and natural gas-fired power plants. This low cost depends on the reliability of boiler and turbine technology and their ability to withstand significantly increased temperatures (Figueroa et al., 2008).

Chemical Looping with Oxy-combustion

A limestone-based oxygen carrier would create a highly concentrated CO_2 stream and allow for reuse of the flue gas stream in a loop that requires no new release of oxygen to facilitate combustion (Figueroa et al., 2008). Thus, there is no need for an oxygen plant to supply the oxygen for combustion. Research has shown that this technology has great potential to be the lowest-cost option for CO_2 capture and removal, with an increased cost of electricity (COE) at less than 20% (Ciferno, 2010). This process produces combustible gas and enough excess heat to power an auxiliary turbine by steam and thereby reduce the total COE. Obstacles for this option include developing an oxygen carrier material that can withstand high temperature conditions, transporting the solids in the stream, and advancing membrane and air separation unit technologies (Ciferno, 2010).

Pre-Combustion Carbon Capture Systems

Removing CO_2 from a pre-combustion stream is an efficient way of capturing carbon ready for storage. There are many different pre-combustion methods, some ready for use in electricity generation and others still in the laboratory test phase. Examples of these processes include integrated gasification combined cycle (IGCC) for synthesis gas (syngas) production, use of physical solvents, ceramic membranes, or sorbents to absorb the CO_2 from syngas, and a process of chemical looping combustion and gasification.

In pre-combustion capture systems, CO_2 is recovered from the process stream before the fuel is burned. Because the CO_2 is removed or diverted before combustion, the stream remains pure and highly concentrated, and requires little to no treatment before storage. Pre-combustion capture is more economical than post-combustion capture because flue gas contains only 14% CO_2. As pre-combustion capture involves converting fuels to a syngas, flue gases contain less concentrated amounts of CO_2 than the flue gases of non-gasified fuels (Figueroa et al., 2008).

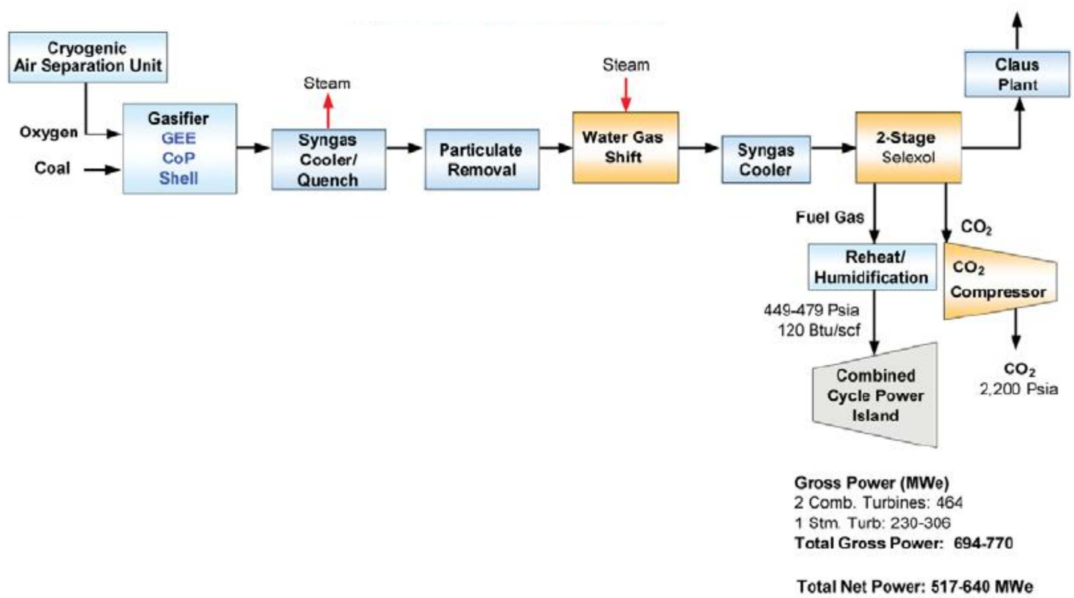
In the pre-combustion sorbent process, CO_2 is filtered through porous materials such as a lithium silicate, while kept at a high temperature and pressure. These materials are ideally suited for removal of CO_2 from syngas due to their ability to withstand high pressures and temperatures, and their ability to remove nearly all CO_2 from simulated syngas. Pre-combustion sorbents offer greater adsorption capacities at higher pressures than when chemical adsorbents are used. The sorbents are thereby more energy efficient as pressures do not need adjustment between the stages of syngas production, CO_2 removal, and combustion. Given that energy loss does not occur and that pre-combustion sorbents regenerating at a high rate require little replacement, this technology has a promising future. If current testing shows this material is able to perform on a commercial level, sorbents may quickly become one of the more economical choices for CO_2 removal from IGCC and other solid fuel gasification plants (Drage et al., 2010).

The costs of pre-combustion capture are still difficult to estimate. Although some of these technologies have already been tested and are available for use today, others will need more testing and pilot programs before commercial viability can be achieved.

Integrated Gasification Combined Cycle (IGCC) Systems

CO_2 capture prior to combustion depends on the coal gasification process. Coal slurry (coal and water) first reacts with oxygen at high temperatures to produce synthesis gas, which is a mixture of CO, H_2, and small amounts of nitrogen and sulfur. Steam is then added to the syngas and sent to a shift converter where the water-gas shift reaction converts CO to CO_2 and H_2. The H_2 is mixed with steam or nitrogen and sent to a combustion turbine while the CO_2 is separated. The CO_2 can then be captured, often in combination with sulfur removal, an operation mandated by the federal Clean Air Act. As in the NGCC process, the combined cycle occurs when a heat recovery steam generator (HRSG) acquires the exhaust heat from the combustion turbine that produces steam for the steam turbine. This produces additional power and increases overall process efficiency (Figueroa et al., 2008). By removing the emission-forming components from the syngas under pressure before combustion, an IGCC power plant produces very low amounts of air pollutants and volatile mercury.

Figure 4: IGCC Process with Carbon Capture



U.S. DOE/NETL, 2007c

Retrofitting Existing Coal-Fired Plants

An examination of carbon capture and storage in the United States would not be complete without a discussion of retrofitting existing coal-fired power plants for capture. Although construction of new coal-fired power plants has slowed in the last twenty years, the existing fleet is very large and likely to remain in use for decades to come. Given the size of the existing fleet and its assumed contribution to baseload generation in the near future, a greenhouse gas stabilization target cannot be met realistically without reductions from the existing fleet (MIT, 2009). According to the EIA, 76% of coal-fired carbon emissions will be attributed to existing coal-fired power plants in 2030 (EIA, 2007).

A survey of the existing coal-fired power facilities in the United States found 782 plants currently in operation with a summer capacity greater than 100 MW (EIA, 2010). The average age of these plants is approximately 40.4 years but that average is heavily influenced by the 50% of plants that are greater than forty years. The most important data for this analysis is the generation capacity by age: 70% of generating capacity is less than forty years old with 38.4% falling in the 31 to 40 year old range. This age group of plants will be crucial for retrofitting analysis, as many of these plants are candidates for retrofitting.

Table 2: Generating Units in the United States with 100 MW or greater Summer Capacity by Age of Unit (EIA, 2010a).

Age Range (years)	Number of Units	% of Total	Summer Capacity (MW)	% Of Total
0-10	11	1.4%	4,084	1.4%
11-20	29	3.7%	9,659	3.3%
21-30	134	17.1%	73,205	25.3%
31-40	210	26.9%	111,129	38.4%
41-50	194	24.8%	58,026	20.1%
51-60	203	26.0%	32,946	11.4%
61 and up	1	0.1%	110	0.0%
Total	782	100.0%	289,159	100.0%

There are a number of challenges to retrofitting existing units. Such challenges will reduce the total number of plants that are likely candidates for retrofits. First, space limitations are a significant challenge. Carbon capture infrastructure requires several acres of space and many plants do not have this space available. Second, other pollution control devices will need to be installed on those plants that do not have them currently installed. For example, current MEA systems are unable to process flue gas streams containing modest amounts of sulfur dioxide. These plants will have to be fitted with state-of-the-art pollution control systems.

Current capture technology requires a 40% increase in water use for operation, so supplying the retrofitted plant with adequate water will also be a challenge. The regeneration aspect of the capture process requires a large amount of water, as does the need for additional steam in the separation process. For a unit to be economically attractive, a sufficient water supply must be in the proximity of the generating unit. Other challenges to retrofitting existing units include engineering large modifications, proximity to storage options, and maintaining expected generation throughout the construction process (Ciferno, 2007).

The estimated additional costs required for retrofitting plants will vary depending on how these challenges are addressed. For example, from December 2005 to December 2006, the DOE funded a feasibility study at the AEP Conesville Plant near Conesville, Ohio. A 430 MW unit was retrofitted for a MEA capture system. This particular unit was originally constructed in 1976 and required a flue gas desulfurization unit. Capital costs were well below what was expected and totaled approximately $327,000,000 when completed (Ciferno, 2007).

The Conesville retrofit provided interesting results. First, no major technical barriers existed when retrofitting the unit with an amine-based capture system. Second, the retrofit additions consumed approximately four acres of land space. This study also revealed relationships between the percentage of carbon captured and the costs associated with capture. A linear relationship was found for the overall plant efficiency and the level of capture. The efficiencies range from 24.4% to 31.6% as the capture rate decreases from 30% to 90%. A linear relationship was also found for incremental investment costs. These costs ranged from $540 to $1319 per kWe as the capture rate increases from 30% to 90%. Finally, it should be noted that this study was conducted in 2007 and there have since been advances to these amine systems that would improve plant performance (DOE/NETL, 2007). However, it should also be noted that initial capital costs have increased significantly in recent years for power plant construction and the $327,000,000 cost for the Conesville facility is likely lower than current costs.

More research will need to be conducted to lower the overall costs of capture systems and to eliminate or reduce the challenges discussed above. Additional research will also need to be conducted regarding specific characteristics to narrow the list of plants most suited for retrofits. Those most likely retrofit candidates will have sufficient water supplies, will be close to suitable geologic storage sites, and will be larger plants of moderate ages.

Capture Risks

Human Health

Currently, little is known about health risks related to the amines used for large scale CO_2 capture. Some amines and amine degradation products can have negative effects on human health through irritation, sensitization, carcinogenicity, and genotoxicity.

These impacts represent worst-case scenarios, and the possible impacts are strongly dependent on the type of amines used in the CO_2 capture process and the actual amount of amine emissions. Currently, a wide range of research activities are continuing to develop new and improved amines, or mixtures of amines, for CO_2 capture. While the main purpose of this research is undoubtedly to reduce the energy consumption in the CO_2 capture process, and hence its cost of operation, it also has a clear objective to minimize health and environmental impacts (Shao and Stangeland, 2009).

Environmental

Environmental concerns also arise from the construction and operation of CO_2 capture systems. While offering considerable ecological benefits through a reduction in greenhouse gas emissions, the installation of capture units for post-combustion treatment could induce unintentional and potential burdens to the environment through four emission pathways: treated gas, process wastes, fugitive emissions, and accidental releases. For example, amines can also be toxic to animals and aquatic organisms, with eutrophication and acidification occurring in marine environments (Shao and Stangeland, 2009).

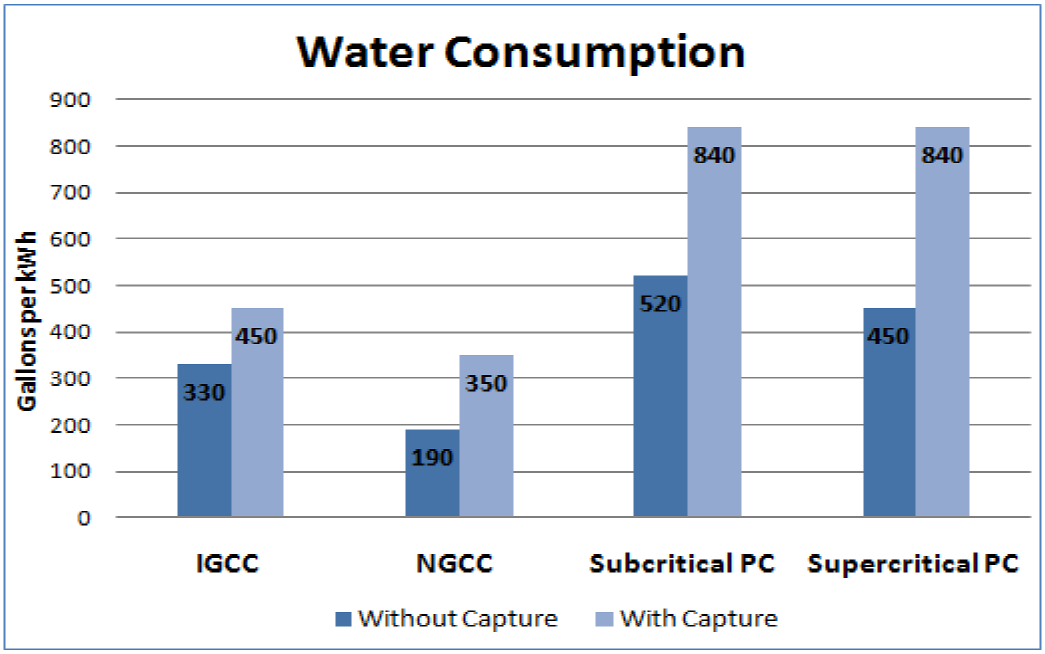
CO_2 capture systems also require significant amounts of energy for their operation. This reduces net plant efficiency, thereby requiring power plants to use more fuel to generate each kilowatt-hour (kWh) of electricity. The increased fuel requirement results in additional emissions per kWh generated relative to new state-of-the-art plants without CO_2 capture. In the case of coal, this also means proportionally larger amounts of solid limestone used by pulverized coal plants for nitrogen oxide and sulfur dioxide emissions control (Thitakamol et al., 2007).

Water Resources

Water withdrawal and consumption are important consequences of electric power generation and will change if carbon capture and storage is implemented. Water use is defined as the overall water supply that is impacted through water withdrawal. Water consumption is defined as the water lost from a water source, which typically occurs through evaporation. A plant using a once-through cooling cycle withdraws water from a source, applies it in the once-through cycle, and then returns it to its source. An estimated 1% of water is lost, or consumed, through evaporation or leaks during this process. If a plant uses cooling towers which re-circulate the water, less water is withdrawn but more water is consumed through evaporation. Water consumption through this process is estimated at 70-90% of the water withdrawn. Although a once-through system withdrawals significantly more water from a source, a re-circulating system consumes approximately ten times more (Hoffman et al., 2004).

In Figure 5, water consumption is illustrated for four electricity generating technologies with and without capture of CO_2. All facilities are assumed to be 500MW plants. NGCC is the lowest consumer of water, meaning that out of the four technologies compared, it loses the least amount of water to evaporation or leaking (DiPietro, 2009).

Figure 5: Water Consumption with and without Carbon Capture



*Water consumption is calculated for a 500MW plant using wet re-circulating cooling towers.

Although most water is used for cooling, power plants use water for blow-down of boilers, flue gas desulfurization units, washing of stacks, sanitation, and waste water treatment. Waste water is typically sent to public waste water treatment facilities or the plant's onsite waste water facility. Therefore, the capacity of local waste water treatment facilities needs to be considered.

Water resources are becoming increasing important, beyond the traditionally arid western United States. For example, the drought of 2007 in the southeast U.S. forced nuclear plants to decrease output by up to 50% due to a decrease in river water levels. In addition, plants' water use may be regulated by the EPA under the Clean Water Act, which will set requirements on design, location, and capacity of cooling water systems to use the best technology available, with the intent to minimize negative environmental impacts (DiPietro, 2009).

Capture Externalities

Carbon capture requires an increase in amount of coal used to produce a given amount of electricity. According to the IPCC, coal plants should be expected to use 10-40% more energy per unit of electricity produced. IGCC is the lowest option at 14-25% energy increase, and pulverized coal power plants would use 24-40% more, with mineral carbonates using 60-180% more (IPCC, 2005). This higher energy use will lead to environmental impacts from increased coal mining, higher coal prices, and faster exhaustion of the resource (Pehnt and Henkel, 2009). If both IGCC and pulverized coal power plants used carbon capture, then domestic consumption of coal resources would increase from 20.6 quadrillion BTU to 25.75 quadrillion BTU, an average increase of 25.75% (EIA, 2008).

Other externalities of carbon capture include the potential of more mountaintop removal mining and the degradation of water in coal mining areas that accompany an increase in mining (Derbach, 2009). In addition to mining, there are environmental impacts along the process chain, such as solvent production and disposal, energy requirements for solvent regeneration, and energy requirements for CO_2 transportation.

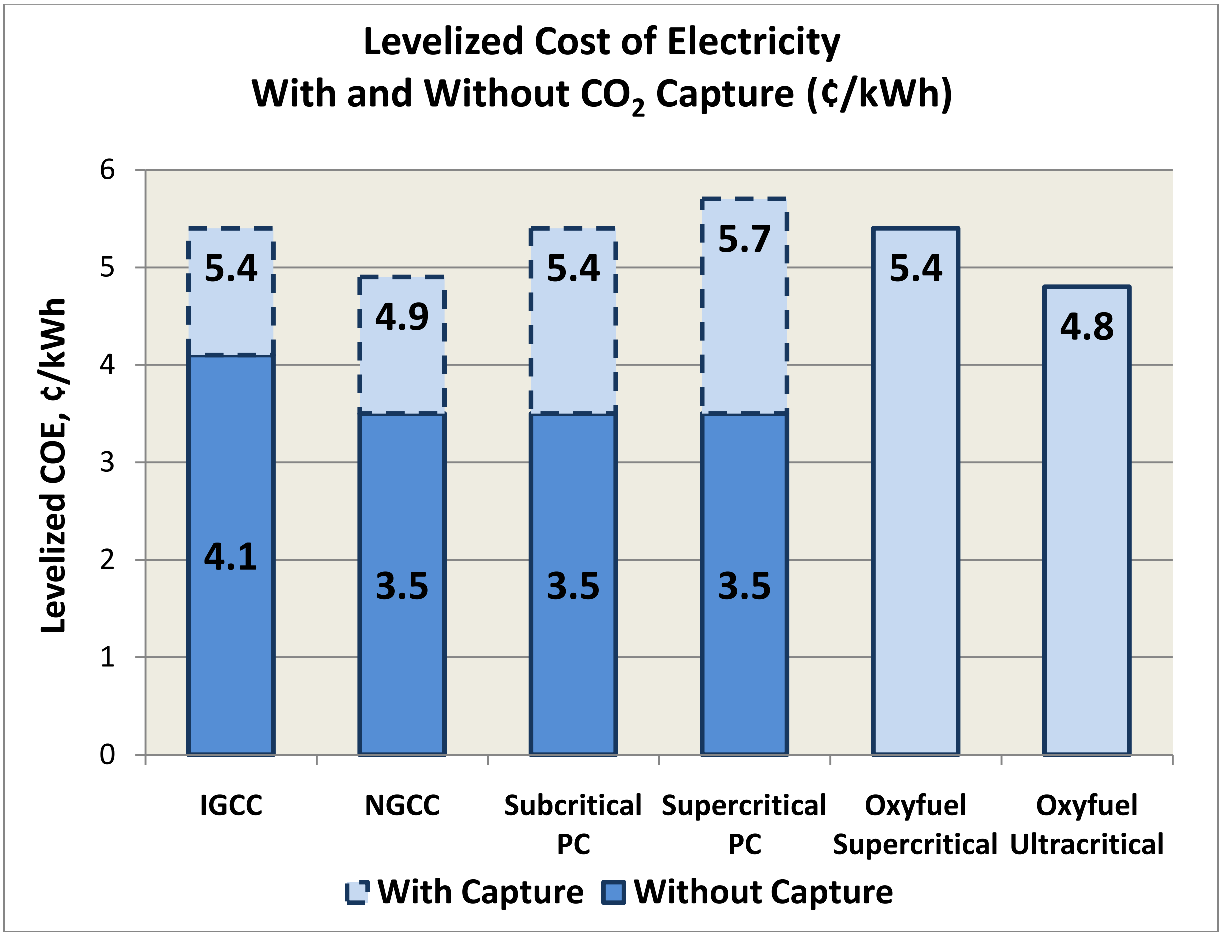
Capture Cost Analysis

The plant size and lifetime parameters in this cost analysis were based on expected levels for commercial-scale facilities with conventional technology. The plant types included in the base analysis are: IGCC, NGCC, subcritical pulverized coal, supercritical pulverized coal, oxy-fuel ultra critical, and oxy-fuel ultra supercritical (Figure 6).

The cost analyses include the reduction of net plant output and added energy costs, often referred to as energy penalties. For amine-based systems energy penalties have been estimated between 15% to 30% for natural gas and 30% to 60% for coal (Herzog, Drake and Adams, 1997; Turkenburg and Hendriks, 1999; David and Herzog, 2000). The capture technologies currently in development seek to reduce these penalties to less than 20% through better integration of capture systems and improvements in absorption of CO_2 (Anderson and Newell, 2003). The Department of Energy (DOE) estimated in 2009 that the sum of all energy for carbon capture application to existing coal-fired power plants could equal 20% to 30% of the plants' output without capture (Myhre and Stone, 2009).

Additional cost analyses presented later in the report (Chapter VII) include low carbon alternative plant types such as nuclear, on-shore wind, on-shore wind with NGCC backup, on-shore wind with NGCC backup plus capture technology, off-shore wind, solar thermal, and solar photovoltaic.

Figure 6: Levelized Cost of Electricity with and without CO_2 Capture



IGCC – integrated gasification combined cycle; NGCC – natural gas combined cycle; PC – pulverized coal

It is important to note that this cost analysis does not include water consumption, criteria pollutants, release of non-carbon greenhouse gas emissions, transmission costs, and power dispatch characteristics. These factors could play an important role when choosing power generation technologies, carbon capture and storage technologies, and the regional placement of power plants (U.S. DOE/NETL, 2007b). Unlike coal technologies, the combustion of natural gas emits negligible quantities of SO_2 and particulate matter. Likewise, IGCC emits substantially less SO_2 and particulate matter than pulverized coal options.

Chapter III: Carbon Transport

Carbon Transport Technologies

Current carbon transport options are limited to land transport, including pipeline, highway and rail, and water transport by ship. At this time, unlike carbon capture and storage technologies which are still in the development process, carbon transport technologies are fairly well known and developed. The current issues associated with the transportation of CO_2 are concerned with the proximity of storage facilities to CO_2 generating sources. New policy and regulations may be needed in order to deploy CO_2 pipeline transportation and storage infrastructure on a large scale.

Land Transport

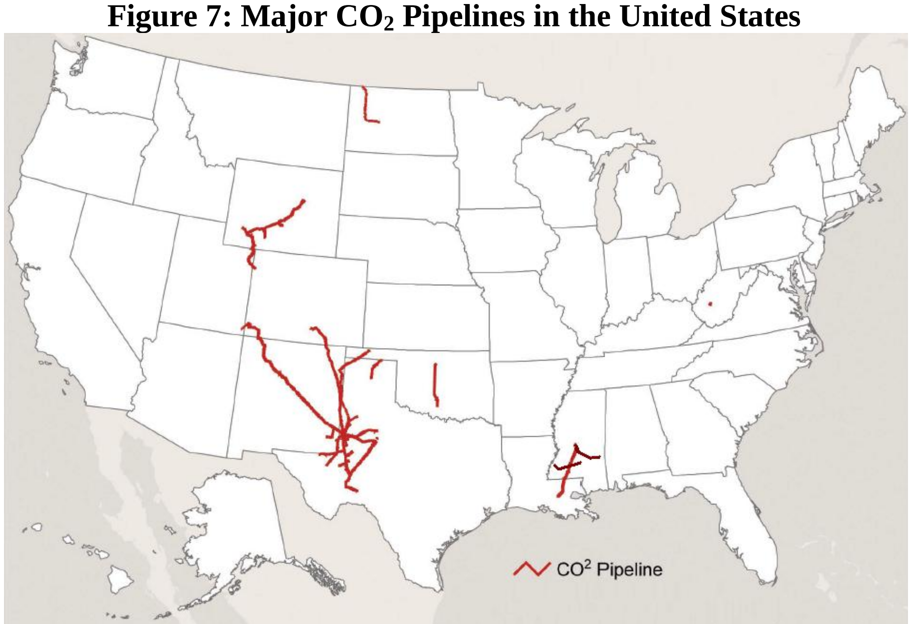
Captured CO_2 can be transported over land through the following methods:

1. Low-pressure CO_2 gas pipelines operating at a maximum pressure of 4.8 MPa (maximum pressure);
2. High-pressure CO_2 gas pipelines operating at a minimum pressure of 9.6 MPa;
3. Refrigerated liquid CO_2 pipelines;
4. Highway tank trucks and rail tankers.

Pipelines

Pipeline transportation technology for CO_2 is similar to that of natural gas; therefore pipeline infrastructure currently exists throughout the U.S. (Folger, 2009). In 1972 the first long-distance (225 km) pipeline was built to transport CO_2 for enhanced oil recovery (EOR) in West Texas oil fields (Kinder, 2007). Figure 7 shows major CO_2 pipelines in the United States, totaling approximately 5,800 km (3,600 miles) in length (Folger, 2009).

Figure 7: Major CO_2 Pipelines in the United States



Denbury Resources Inc, 2005

Although capable of handling higher volumes of CO_2, refrigerated liquid CO_2 pipelines are unlikely to be used because of the high cost and technical difficulties associated with liquefaction. Transporting CO_2 as an intermediate pressure gas (between 4.8~9.6 MPa) is not currently an attractive option because of the potential for CO_2 to flow in two phases, gas and liquid, simultaneously. High-pressure CO_2 gas pipelines are the most likely to be used because the compressed CO_2 volume is smaller during transportation and high pressure also is needed to inject CO_2 in the storage (IPCC, 2005).

Truck and Rail

Liquefaction facilities will be required to reduce the CO_2 volume for truck or rail transport. Although CO_2 transport by both truck and rail tankers is technically feasible, the large amounts of CO_2 that will need to be transported make these options not cost effective; thus, neither are likely to be used to any extent.

Ships

When suitable storage sites are located in or across an ocean from the sources, it is possible that CO_2 would be transported by ship. The transport cycle requires storage, loading, and liquefaction facilities to reduce the CO_2 volume for ship transport. Transporting CO_2 by ship is similar to that of liquefied petroleum gas (LPG); therefore, current technologies can be applied to new infrastructure for CO_2 transport (IPCC, 2005).

Liquefied food-grade CO_2 is transported from large point sources, such as ammonia plants, to northern Europe for distribution. Norway and Japan are currently designing larger CO_2 carrying ships and associated liquefaction and intermediate storage facilities. Historically, operating oil and gas ships, and marine transportation have been susceptible to various accidents; and therefore, methods need to be thoroughly researched before they can be fully implemented (IPCC, 2005).

Transport Risks

Pipelines

Pipeline routing, construction, and maintenance can have an impact on the environment, as well as pose a threat to local health and safety should a CO_2 leak occur. Risks to local populations and ecosystems range from asphyxiation of flora and fauna to the acidifying effects on soil, surface, and groundwater. If substantial quantities of impurities, particularly H_2S, are included in the CO_2, this could affect the potential impacts of a pipeline leak or rupture. The exposure threshold at which H_2S is immediately dangerous to life or health is 100 ppm, compared to 40,000 ppm for CO_2 (IPCC, 2005).

In terms of pipeline failure, an incident is defined as an event that released gas and caused death, in-patient hospitalization, or property loss of at least $50,000. Pipeline failure incident rate of approximately 0.001 km per year in 1972 fell to below 0.0002 km per year in 2002. Most of the incidents refer to very small pipelines, less than 100 mm in diameter, principally applied to gas distribution systems. The failure incidence for 500 mm and larger pipelines is much lower, 0.00005 km per year. From 1997 to 2001, the related incident frequency for western European oil pipelines was 0.0003 km per year^{-1}. The related figure for U.S. onshore gas pipelines was 0.00011 km per year from 1986 to 2002. The difference in the reporting threshold is thought to account for the difference between European and U.S. statistics (IPCC, 2005).

Ships

The total loss of CO_2 to the atmosphere is between 3-4 % per 1000 km traveled by ship, counting both boil-off and the exhaust from engines. Boil-off could be reduced by capture and liquefaction, and recapture would reduce the loss to 1-2% per 1000 km. Shipping systems can fail in various catastrophic ways: through collision, foundering, stranding, and fire (Barrio et al., 2004). Liquid CO_2 is not as cold as liquefied natural gas (LNG), nor is it flammable, though it is denser. In the case of a collision, the possibility of fire or explosion is thus lower than with LPG, LNG, and oil carriers. Due to its density, however, CO_2 can cause asphyxiation as well as stop the ship's engine. As a result of the immediate and long-term effects of CO_2 liquid leakage, further research is needed (IPCC, 2005).

Transport Cost Analysis

Pipelines

This cost analysis focused on CO_2 pipelines as the primary method of transportation. Pipelines are expensive to build, but operate at substantially lower costs when compared to ship, rail or truck transport. Costs associated with pipeline transportation systems are composed of three major elements: 1) construction costs (e.g., material, labor, and possible booster station), 2) operation and maintenance costs (e.g., daily operation, monitoring), and 3) other costs (e.g., insurance, fees,) (IPCC, 2005). According to a study analyzing the construction costs for pipelines built in the United States between 1991 and 2003, on average the material costs accounted for approximately 26% of the total construction costs, while labor, right of way, and miscellaneous costs made up 45%, 22%, and 7%, respectively (Parker, 2004). This study estimated average total construction costs for the pipelines constructed between 1991 and 2003 as $800,000 per mile in 2002 dollars (Parker, 2004).

The total construction cost is dependent on the length of the pipeline. One study analyzed 2,082 sources of CO_2 (i.e., power plants, natural gas processing plants, refineries, and other industrial plants), and estimated that it is possible to store 77% of the total annual CO_2 captured, beneath the respective plant (Dahowski et al 2005). If so, a smaller number of long-distance pipelines would be needed and as a result, transport costs would contribute a relatively small amount to the total carbon capture and storage costs.

A Massachusetts Institute of Technology (MIT) 2007 analysis estimated that the majority of coal-fired power plants are located in regions with storage sites nearby. Therefore, the cost of transport and injection of CO_2 should be less than 20% of total cost for capture, compression, transport, and injection (MIT, 2007). Figure 8 shows the locations of major coal-fired generating plants overlain with potential carbon storage reservoirs.

Figure 8: Location of Coal-fired Generating Plants Relative to Potential Storage Sites

MIT, 2007

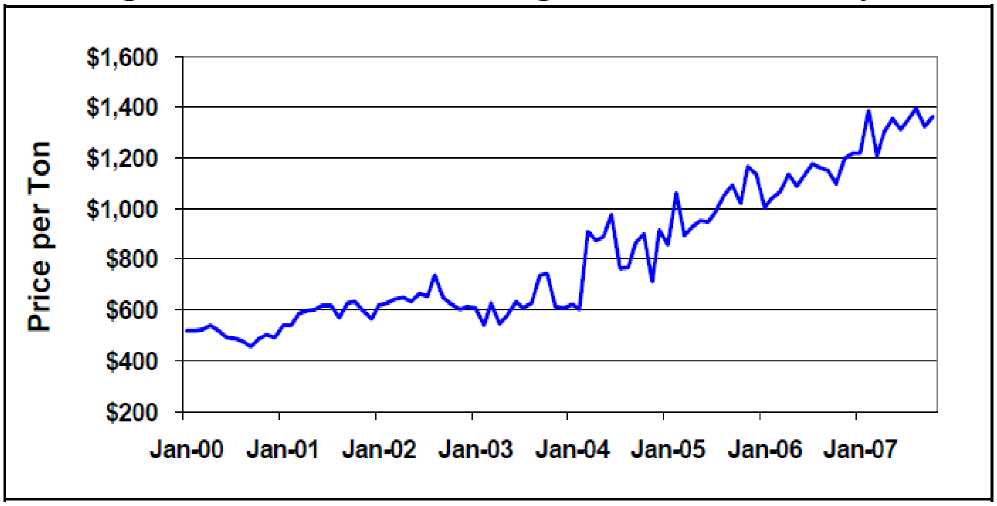
However, other analysts (Stevens and Van Der Zwaan, 2005) suggest that captured CO_2 may need to be stored, at least initially, in more centralized reservoirs to reduce the potential risks associated with CO_2 leaks. If this is the case, then many long-distance pipelines would be necessary to connect sources to centralized storage, therefore requiring a large-scale, interstate CO_2 pipeline network.

The pipeline's location and topography significantly affect the cost. Special land conditions such as heavily populated areas, protected areas (e.g. national parks), or crossing major waterways may also have a significant impact on overall cost. It is important to note that offshore pipelines are approximately 40 to 70% more costly than onshore pipes of the same size (IPCC, 2005).

Another major cost factor is the quantity of CO_2 being transported. The International Panel on Climate Change analyzed the cost of pipeline transport between 1 to 8 U.S. \$/tonne CO_2 for a nominal distance of 250 km, with the cost highly dependent on the CO_2 mass flow rate (IPCC, 2005). The MIT report also concludes that transport costs are highly non-linear for the amount transported, with economies of scale being realized at about 10 Mt CO_2/yr (MIT, 2007).

The price of steel, the pipe diameter, and pipe quality with regard to corrosion are significant factors affecting pipeline material costs. The MIT 2007 study stated that the transportation of captured CO_2 for a one Gigawatt coal-fired power plant would require a pipe diameter of about sixteen inches and a transport cost of about \$1per tonne of CO_2/100 km (MIT, 2007). It is necessary to take the rising steel pipe cost into consideration when looking at overall implementation costs. The price of large-diameter pipe was around \$600 per ton in late 2001, whereas by late 2007 it had increased to \$1,400 per ton. This substantial increase in price is the result of a strong demand for and increased production costs of carbon steel plate, used in making large-diameter pipes. These costs, particularly if they keep increasing, may alter the costs of CO_2 pipeline projects (Parfomak and Folger, 2008). Figure 9 shows the upward trend of steel pipe prices during from 2000 to 2008.

Figure 9: Prices for Large Diameter Steel Pipe in the United States



Preston Pipe and Tube Report, 2007

Pipeline quality, including the ability to endure corrosion, is crucial to preventing accidents. Dry CO_2 does not corrode the carbon-manganese steel used for pipelines, as long as the relative humidity is less than 60%, even if the CO_2 contains contaminants such as oxygen, hydrogen sulfide, and sulfur or nitrogen oxides. However, moisture-laden CO_2 is highly corrosive; a CO_2 pipeline must be made from a corrosion-resistant alloy or be internally clad with an alloy or continuous polymer coating (IPCC, 2005). The material costs for corrosion-resistant alloy increase significantly in comparison to carbon-manganese steel.

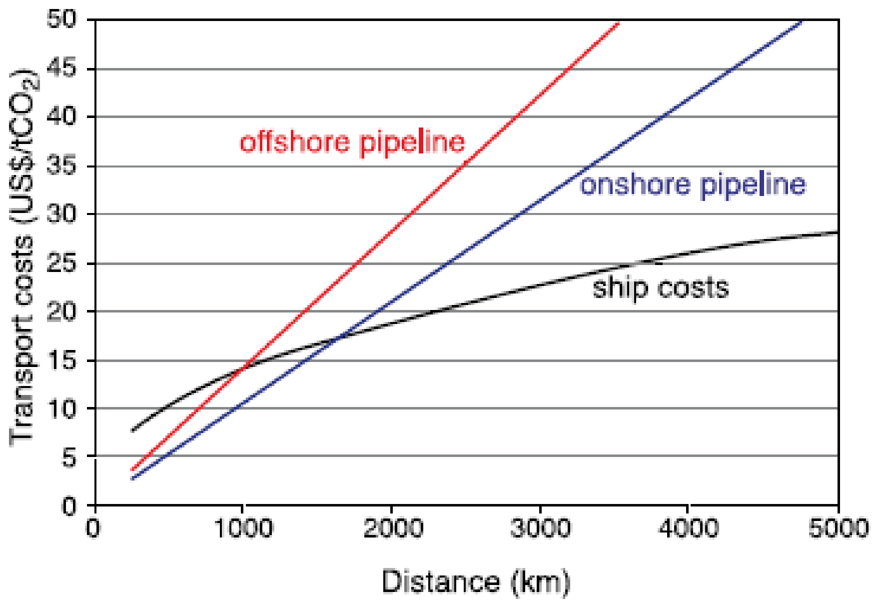
Ships

There are several key factors determining overall CO_2 transport costs in marine-based systems: the tanker volume and the characteristics of the loading and unloading systems. According to an IPCC report, if marine transport becomes a viable option, it is likely to be cheaper than using pipelines to transport CO_2 over distances greater than 1000 km and for amounts smaller than a few million tons of CO_2 per year (IPCC, 2005).

Ship transport may be useful in longer distances; however, it induces more associated CO_2 transport emissions than pipelines because of the additional energy used for liquefaction and fuel. The International Energy Agency (IEA) Greenhouse Gas R & D Program estimated an extra 2.5% in CO_2 emissions for a transport distance of 200 km and about 18% for 12,000 km (IEA, 2006). The extra CO_2 emissions for each 100 km pipeline are approximately 1 to 2% (IPCC, 2005). As the quantity transported becomes larger, the break-even point moves toward longer distances. In addition to construction costs, loading terminals and other various factors should also be considered to evaluate exact costs.

Figure 10 illustrates costs that include: intermediate storage facilities, harbor fees, fuel costs, loading/unloading activities and costs for liquefaction compared to compression. There is also a capital charge factor of 11% for all transport options (IPCC, 2005).

Figure 10: Transport Cost by Ship and Pipeline as a Function of Distance



Chapter IV: Carbon Storage

Carbon Storage Technologies

Carbon dioxide storage technologies include geologic, carbonate mineralization, and oceanic processes.

Geologic Storage

There are five main geological formations into which CO_2 can be injected and stored:

1. Oil and gas reservoirs
2. Deep saline formations
3. Un-mineable coal seams
4. Oil and gas rich shale
5. Basalt formations

Each of these formations has a different capacity for holding and trapping CO_2, and each method of geologic storage has different cost components and projections. The storage of CO_2 can occur in a variety of geologic formations chosen for their ability to effectively trap CO_2, the capacity of the formation to accept the intended volume of CO_2, and the area's ability to limit the extent to which it migrates throughout the formation.

Achieving geologic storage involves injecting fluids into wells, located on or offshore, that are perforated or covered with a porous screen to allow the carbon dioxide to enter the formation. The CO_2 first must be compressed to a dense, fluid state before it can be injected into the ground; the density required will increase with the depth of injection. Depending on the site and the formation, the screen will provide different capping capabilities because pressure buildup varies with each storage site. Pressure buildup allows CO_2 to enter porous spaces in the formation into which it is injected, thus enabling it to displace other fluids already occupying those spaces. The amount of distribution and pressure buildup depends on the injection rate, the permeability of the formation, and the presence or absence of permeable barriers within it, as well as the geometry of the regional underground water system (IPCC, 2005).

Carbon dioxide can be transported via pipeline to offshore sites; however, much of the sediment at offshore sites is thin and impermeable, making storage more difficult. A number of onshore locations in the U.S. and North America have been identified as potential sites for storage, with deep saline formations holding the majority of storage capacity (Dooley et al., 2004).

Oil and Gas Reservoirs

Oil and gas reservoirs contain porous rock that once held crude oil and/or natural gas. An impermeable rock formation overlays the well and acts as a seal to trap the oil and gas. It is possible to apply this same mechanism to trapping injected CO_2. In addition to long-term storage, the process of injecting CO_2 into these reservoirs aids in recovering difficult to reach oil reserves. Enhanced oil recovery (EOR) occurs when CO_2 is injected into wells that hold otherwise unreachable reserves. The carbon dioxide acts buoyantly to push the crude oil toward the top of the well making it easier to recover. This not only makes for a more efficient recovery of the resource, but it also requires less energy to power the oil recovery process. The EOR process is relatively well developed, but the amount of CO_2 that is offset by the process is minimal compared to what could be stored in saline formations and long-term storage technologies in oil and gas reservoirs are less certain (EPRI, 2007).

Saline Formations

Saline formations that can be used as potential CO_2 storage sites consist of porous rock saturated with brine with a cap of impermeable rock formations to serve as the trapping mechanism for the CO_2 once it is injected. These types of formations have a higher storage capacity and are more widespread in terms of their location in comparison to oil and gas reservoirs and coal seams. However, the ability of saline formations to trap CO_2 and keep it from migrating is less understood than the capabilities of other geological formations; still, these formations are often considered the most promising option for storage today. There are several reasons for this; first of all, saline formations are the most abundant of the viable geologic formations in the U.S. Additionally, these formations have several voids partially filled with brine which will allow more CO_2 to be injected. This additional storage capacity comes from the ability of the CO_2 to move into the spaces previously occupied by the brine and dissolve in the water. Eventually, it would form stable, solid compounds that would permanently isolate the CO_2 (EPRI, 2007).

Un-mineable Coal Seams

Un-mineable coal seams are those found beyond typical recovery depths. Most coals are capable of adsorbing CO_2 resulting in release of previously stored methane. This process, called Enhanced Coal-Bed Methane (ECBM) recovery, is an added benefit to the storage process because it creates a lower net cost option because recovery can take place at shallower depths than EOR. In order to use un-mineable coal seams more research is needed to fully understand this option. NETL lists these as: 1) storage capacity in coal seams, 2) geologic and reservoir data defining favorable conditions for injection sites, 3) additional understanding of the interactions between CO_2 and coal, 4) reliable, high-volume injection strategies, and 5) integrated CO_2 storage and ECBM recovery (U.S. DOE/NETL, 2007b).

Shale and Basalt

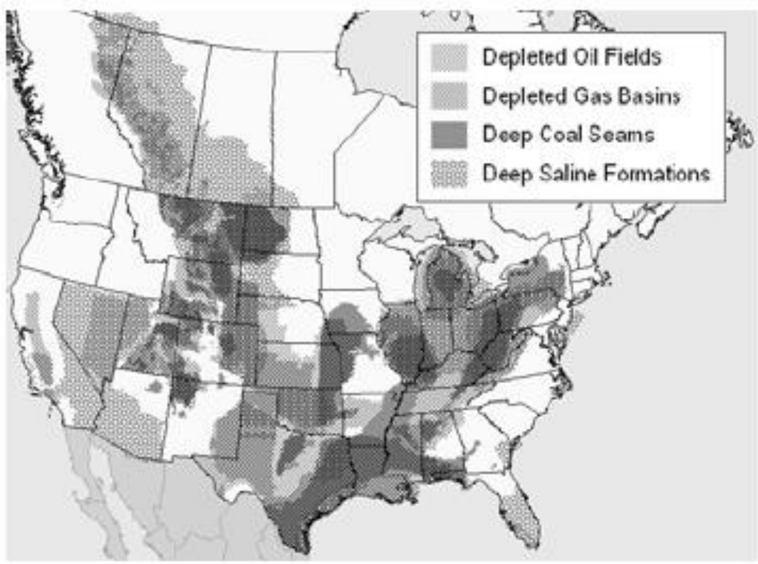
Shale and basalt formations offer additional geologic storage options due to their relatively common occurrence throughout the U.S. Shale is the most common type of sedimentary rock and is comprised of thin horizontal layers of rock with low vertical permeability. The organic materials found in these layers provide a means for CO_2 adsorption through a process similar to ECBM in which shale-gas production is enhanced and the overall cost for CO_2 storage is reduced. It would be difficult to inject large volumes of CO_2 because of low permeability of shale.

Additionally, basalt, created from lava formations, has a chemical makeup that increases the potential to convert all injected CO_2 into mineral form or "carbonate minerals." This process would essentially permanently isolate the CO_2 from the atmosphere. Research on this technology is still very new, but it is understood that the process of mineralization takes thousands of years (U.S. DOE/NETL, 2007b). Basalt is also very porous, posing the potential for leaking before mineralization can take place, and therefore a caprock would be necessary. According to the IPCC, storage in basalt formations is unlikely due to the lack of understanding about the technology and its high cost relative to other storage options (2005).

Geologic Storage Capacity

According to Dooley et al. (2004), the United States will need approximately 62.5 gigatons (Gt) CO_2 of geologic storage capacity over the course of this century with their projections of actual capacity in North America, at 3,800 Gt CO_2, far exceeding the needed capacity. Other estimates, such as those from the IEA (2009), project that North America has a geologic storage capacity of anywhere between 2,170 and 4,650 Gt CO_2. Figure 11 depicts potential storage reservoirs.

Figure 11: Potential Storage Reservoirs in North America



Dooley et al., 2004

Based on a review of 14 different capacity assessments that take into account several different factors, the full worldwide range for geologic storage capacity is estimated at 200-56,000 Gt CO_2, with the lower range number for storage in only deep saline formations. However, given this very large range, the IPCC developed estimates that storage capacity in deep saline formations is at least 1,000 Gt CO_2 worldwide (2005). It is estimated that deep saline formations worldwide have a capacity between 100 and 1000 Gt CO_2 (Herzog, 2001). Depleted oil and gas reserves have the potential for sequestering hundreds of Gt $CO_{2,}$ and coal seams, tens to hundreds Gt CO_2. Although there is a wide variation in the ranges of potential storage capacity estimates, all estimates are well over the estimated *need* in terms of capacity, indicating that the U.S. and the world would have more than enough space to store its emissions over the next 100 years and beyond.

Deep saline formations present the highest geologic storage capacity in the United States. Saline formations account for approximately 97% of the total identified onshore capacity (Dooley et al., 2004). Additionally, these formations are so widespread that transport requirements are minimized, thus decreasing the costs further. Depleted oil reservoirs account for 0.3% of storage capacity in North America, equating to 13 $GtCO_2$ of additional capacity.

Once carbon dioxide has been injected into geological formations, it has a tendency to remain at the subsurface, and can potentially remain there for millions of years. Based upon natural gas storage operations, some areas can store oil and natural gas for 5-100 million years (IPCC, 2005). Natural gas storage projects have been operating around the world for over 100 years (Bachu, 2007). This technology offers experience similar to CO_2 storage, particularly because natural gas has been stored in depleted oil and gas reservoirs and saline formations – the storage options identified as most viable for CO_2 storage. These projects have been successful due largely to appropriate site selection, proper design, monitoring, and maintenance of injection wells, and proper assessment of risks in the reservoir (IPCC, 2005).

Storage in oil and gas reservoirs is a well-developed technology that is presently ready for CCS application. EOR methods have been used for over 30 years in the U.S. with the first example occurring in the 1970s in Texas and continuing to today. Oil and natural gas reservoirs are considered lower risk due to the fact that they previously stored gases for millions of years. Currently, many EOR projects in the U.S. are taking place in the Permian Basin in West Texas where CO_2 is transported along a pipeline network from sources mainly in New Mexico and Colorado. Upon arrival, it is subsequently injected into the oil field (Bachu, 2007).

Additionally, different projects have been developing in various locations. In September 2009, the Mountaineer Power Plant in West Virginia announced plans to become the world's first coal-fired power plant to capture and sequester its CO_2 emissions. Beginning in late 2009, the project is estimated to have captured anywhere from 15-30% of the CO_2 emitted and sequester it in a layer of sandstone 7,800 feet below the surface. The project, owned by American Electric Power will inject approximately 100,000 tons of CO_2 annually for two to five years (Wald, 2009).

The DOE, through its Regional Carbon Sequestration Partnership (RCSP) initiative, has selected seven partnerships to explore approaches to capturing and storing CO_2. RCSPs are comprised of state and local agencies, coal, oil, and gas companies, electric utilities, and many other entities as part of a network working to address the issues of suitable technologies, infrastructure needs, and regulation for carbon storage. One such partnership is the Southeast Regional Carbon Sequestration Partnership (SECARB) involving 11 southeastern states. As of April 2009, the project was in its validation phase: assessing injection capacity and containment, advancing monitoring technology, and fostering public awareness and education programs. Using four field studies that store carbon in oil fields overlying deep saline formations along the Gulf Coast, SECARB estimated 34 billion tons of potential storage capacity in the region. Already, one of the four sites, located in Mississippi, has injected 3,000 tons of CO_2 into a deep saline reservoir (U.S. DOE/NETL, 2009e).

While many projects and research focus on onshore storage sites, there also exists a successful example of offshore carbon storage, which began in 1996 at a site in the middle of the North Sea. The Sleipner Project, operated by Statoil, has been injecting CO_2 into deep saline aquifers below the ocean floor since the mid-1990s and monitoring of storage has been carried out since 1996. The IEA Greenhouse Gas R and D Program has arranged monitoring activities and report that approximately 1 Mt CO_2 is removed from the natural gas produced at the Sleipner West Gas Field and injected annually into the formation (IPCC, 2005).

Technological development in the realm of geologic carbon storage involves gaining a larger understanding of the reservoirs into which the carbon dioxide is to be injected as well as the flow and trapping of the gas. The DOE has identified areas into which further research is necessary for each type of geologic storage. For oil and gas reservoirs, shale, basalts, and saline formations, an improved understanding of the trapping mechanisms, the potential for chemical alterations in the geologic formation, and improved predictive modeling for injection have been identified. Additionally, an improved understanding of coal properties and predictive modeling are necessary for research into storage in un-mineable coal seams (U.S. DOE/NETL, 2007a).

In 2006, DOE selected nine projects to develop "novel and cost-effective" technologies for capture and for storage. In terms of storage, researchers are looking into membranes and mineralization technologies, as well as a project that creates microbes that could potentially biologically sequester CO_2 and convert it for use in other areas such as agriculture and food production (U.S. DOE/NETL, 2007a).

Carbonate Minerals

Carbonate mineral storage is another possible option for carbon storage. Mineral storage of CO_2 involves aqueous mineral carbonation reactions that take advantage of the natural alteration of ultramafic or igneous and meta-igneous rock (rock with low silica content, SiO_2, but high magnesium and iron content), a process called serpentinization. At high pressure and moderate temperatures water that comes into contact with the ultramafic rocks alter the serpentine (Gerdemann et al., 2003). Carbon is sequestered naturally in geologically stable mineral magnesite ($MgCO_3$). Two primary classes of magnesium silicate minerals are olivine (Mg_2SiO_4) and serpentine ($Mg_3Si_2O_5(OH)_4$). These are converted into magnesite through time intensive geologic processes. Eventually, serpentine (and other minerals) turn into olivine, making it more prevalent than any other mineral in geologic formations.

These geologic processes can be accelerated by increasing the surface area, the activity of CO_2 in the solution, the reaction temperature, and the pressure, while decreasing the particle size, changing the solution chemistry, and using a catalyst. Studies have shown that conversions of magnesite or calcite formations of over 80% are possible in less than an hour (Gerdemann et al., 2003; Herzog, 2002). In this method, CO_2 is injected and dissolved into a mixture of water and a mineral reactant, such as olivine or serpentine. This mixture of CO_2, water and minerals react forming carbonic acid. The hydrogen cations are consumed by the carbonic acids and solid minerals, therefore liberating the magnesium cations (Mg^{2+}). These Mg^{2+} further react with HCO_3^- to form magnesite ($MgCO_3$). The forming of carbonic acid continues under supercritical CO_2 pressures. The following equations depict these reactions.

$$\underset{\text{Forsterite}}{Mg_2SiO_4} + \underset{\text{Carbon Dioxide}}{2CO_2} + \underset{\text{Water}}{2H_2O} \rightarrow \underset{\text{Magnesite}}{2MgCO_3} + \underset{\text{Silicic acid}}{H_4SiO_4}$$

$$\underset{\text{Serpentine}}{Mg_3Si_2O_3(OH)_4} + \underset{\text{Carbon Dioxide}}{3C0_2} \rightarrow \underset{\text{Magnesite}}{3MgC0} + \underset{\text{Silica}}{2SiO_2} + \underset{\text{Water}}{2H_2O}$$

Fouth et al., 1996

There is approximately 39 million gigatons (Gt) of carbon currently present in carbonate rocks within the Earth's crust. The atmosphere holds approximately 800 Gt of carbon; a relatively small amount in comparison to the geologic formations of the Earth's crust. As described above, the process of forming carbonate minerals from atmospheric CO_2 is a natural part of the long-term global carbon cycle. Roughly 0.1 Gt of carbon is sequestered globally by silicate-mineral weathering. It would take 8,000 years to sequester the existing 800 Gt in the atmosphere through this natural process (Oelkers et al., 2008).

The North Cascades of Washington State contain large deposits of ultramafic rock. The Twin Sisters deposit alone is estimated to contain over two billion tons of unaltered dunite, an ultramafic type of rock that is over 90% olivine. This is enough to carbonate 100% of CO_2 emissions from 8-10 GW coal fired power plants for approximately 15 years (Norman and Storman, 2007). Conversely, open-pit mining at this level would result in significant environmental impacts and require the disposal of large amounts of resulting carbonate minerals.

An advantage of carbonate mineral storage is that it is "permanent," at least in terms of geologic time. This permanence differentiates mineral storage from other storage methods such as terrestrial, geologic, and oceanic. Over time however, these methods have potential for leakage; creating uncertainties and environmental health and safety concerns (Herzog, 2002). The second advantage is that carbonates have a lower energy state than CO_2. The carbonation process actually produces energy, releasing heat. Naturally, both magnesite and silica are found in serpentinized ultramafic rocks. Additionally magnesite is a stable geologic formation that "is not likely to release bound CO_2" (Herzog, 2002). Finally, the raw materials necessary for storage are abundant. Serpentine, olivine and magnesite are found naturally in large quantities all over the world estimated to exceed "even the most optimistic estimates of coal reserves" (Fouth et al., 1996).

Although the reactions given above are stable and thermodynamically favorable, this technology has yet to be developed (Oelkers et al., 2008). Further research and development is needed to speed up the reactions enough to make this technology cost competitive with other storage options. Herzog (2002) points out that studies showing increased reaction rates need to be read with caution. In some cases, the process included "pretreatment" of the minerals, thereby drastically improving the kinetics, but at the cost of increased energy consumption. The kinetics improvements have to be balanced with energy needs.

Oceanic Storage

Deep-sea (or oceanic) injection storage employs features of geologic storage and geochemical storage but does not have some of their problems (House et al., 2006). Carbon dioxide becomes denser than water at high pressures and low temperatures. Due to pressure and temperature changes, when the CO_2 is injected into the deep sea at depths more than 3,000 meters, it sinks to the seafloor. As ocean currents change, the CO_2 mixes with the current and effectively is released. To avoid mixing, the injection must take place below the sea floor.

When CO_2 is injected into the deep sea at a depth of at least 3,000 meters, the CO_2 will be denser than the surrounding pore fluid (the fluid that occupies the pore space within the rock). This pore fluid, due to its lower density, acts as a cap (commonly referred to as a boyancy cap) providing "gravitational stability." This gravitational stability is what differentiates deep sea geologic storage from terrestrial geologic storage.

Preliminary tests have shown that the kinetics of the mineralization reactions are slow at ambient temperature and subcritical CO_2 pressures. In order for this technology to be cost effective, the speed of the kinetic reactions needs to increase by orders of magnitude. O'Connor et al. (1999) have shown that the process speeds up when the temperature and pressure are increased in combination with stirring of the slurry and gas dispersion with the water column. In this situation, the conversion to carbonate minerals occurs at approximately 90% in 24 hours at a temperature of 185° C and partial pressure of CO_2 (P_{co2}) at 11.6 MP_a (O'Connor et al., 1999). In addition, this study demonstrated that there are essentially no very slow reactions when at ambient or elevated temperatures if the P_{co2} is below its critical point of 7.4 MP_a. A test designed to replicate that of an *in situ* situation set the MP_a at 5.2, and temperature at 150° C; this resulted in 10% conversion after 144 hours (O'Connor et al., 1999). Studies have concluded that when temperatures and pressures are increased past the critical points, to supercritial, the rate of conversion will increase as well. Furthermore, this process improves the kinetics of the reactions; with more R & D the process could improve enough to begin projects at the industrial level (O'Connor et al., 1999).

Some literature suggests a potentially more cost effective process would be to store other wastes with the CO_2. For example, it may possible to store CO_2 along with hydrogen sulfide (H_2S), sulfur dioxide (SO_2) or nitrogen dioxide (NO_2). This type of system requires more extensive research, currently the process is too complicated, expensive and the consequences of the stored combinations are unknown (IPCC, 2005).

CO_2 injected into deep oceans has the capability of remaining in place hundreds or thousands of years. If technology can improve the kinetics of the storage processes, then it is possible that deep sea storage will play a large role in carbon storage. Furthermore, the buoyancy cap guarantees that even if the sediment column is disrupted and forms fractures, these fractures will not serve as conduits for CO_2 migration. The CO_2 will not be able to migrate upward for eventual release back into the atmosphere (House et al., 2006). The combination of the buoyancy cap, hydrate formation and carbonate dissolution acts as a nearly full proof system, relinquishing the need for MMV. Finally, within the ocean boundaries 200 meters off the U.S. coast, the storage capacity is predicted to be large enough to store thousands of years of CO_2 emissions (O'Connor et al., 1999).

Storage Risks

Geologic

The main risks associated with geologic carbon storage center around the issue of carbon dioxide leakage. Carbon dioxide can escape from a geologic site through one of the following main mechanisms: the pore system of the caprock; openings within the caprock, fractures, and faults; and man-made wells or injection sites (IPCC, 2005). The types of hazards associated with a leakage vary greatly depending on if the event is a short, abrupt occurrence, or a long-term gradual leak. This section will analyze the risks associated with these different leakage types and the corresponding local and global impacts of such situations.

The main local concern resulting from an abrupt leak is the resulting immediate danger to surrounding life forms. Normal atmospheric conditions contain CO_2 concentrations around 0.038%. Higher concentrations become problematic, with concentrations around 3% resulting in hearing loss, impaired vision, and mental disorientation. At concentrations between 7-10%, carbon dioxide causes asphyxiation and can be fatal (Bachu, 2008).

Should a leak occur, CO_2 would have a tendency to flow towards lower-lying areas because it is 50% denser than air. As a result, shallow depressions and confined areas are at much higher risk for CO_2 concentration build-ups compared to areas with open terrain (IPCC, 2005). Low-lying life forms and small animals may also suffer as a result of CO_2's natural migration tendencies. Occupational standards have been developed for CO_2, and acute exposure safety risks are considered to be similar to those of the oil and gas industry, if not lower because CO_2 is not flammable (Bachu, 2008).

The main determining factors in carbon dioxide concentrations are the size and speed of a leakage. Large and fast leaks have a greater ability to cause atmospheric mixing, reducing carbon dioxide buildup in a small area. Small leaks may disperse slow enough to prevent any drastic carbon dioxide concentration changes and therefore potentially pose very little risk. Therefore, the greatest hazard comes from moderately sized leaks where CO_2 either collects in a confined space or does not sufficiently mix (Bachu, 2008).

Long-term exposure to elevated carbon dioxide levels can overtime also negatively impact ecosystems. Carbon dioxide will most likely lower soil pH and alter ground chemistry. While plants may be able to handle such changes for short periods of time, extended exposure can eventually limit respiration in the roots of plants. Mammoth Mountain California experienced large tree kills when soil concentrations of carbon dioxide were between 20-30% due to volcanic off-gassing (Damen et al., 2006). Monitoring of carbon dioxide near storage areas would be necessary to ensure levels remain at acceptable concentrations.

Another major local concern with geologic storage is the potential contamination of groundwater. Specifically, an increase in dissolved carbon dioxide concentrations has the potential to alter groundwater chemistry. The IPCC explains possible alterations as "dissolved CO_2 forms carbonic acid, altering the pH of solution and potentially causing indirect effects, including mobilization of (toxic) metals, sulfate, or chloride; and possibly giving the water an odd odor, color, or taste. In the worst case scenario, contamination might reach dangerous levels, excluding the use of groundwater for drinking or irrigation" (IPCC, 2005). The risk of groundwater contamination from metal leaching is very low because most storage sites do not contain mineral compositions that CO_2 could alter (IPCC, 2005).

The injection of carbon dioxide will also result in the displacement of brine. Displaced brines have the potential to migrate into shallow aquifers, thus increasing the salinity. Again, such changes could make the groundwater unsuitable for drinking and agriculture. Yet, current industrial analogs involving ground injections of different waste fluids reveal groundwater contamination from displaced brines to be very rare. These low rates are estimated to be similar to those that would occur with large-scale geologic storage (IPCC, 2005).

Induced seismic activity is the final local concern from large-scale carbon dioxide storage. As carbon dioxide is pumped underground, pressure greatly increases within the rock formation. If the pressure becomes too great, ground fractures and movement can occur. These fractures can cause small, micro-seismic events that would result in new pathways for carbon dioxide to migrate and potentially leak back into the atmosphere (IPCC, 2005). Greater seismic activity can also result due to the activation of faults from increased pressures. Activated faults have a greater potential to cause earthquakes, with surface damage and carbon dioxide leakage potentially occurring as a result.

Industrial analogs from natural gas storage and deep waste injection show that seismic risk is minimal, and is not a limiting factor for large CCS deployment (Bachu, 2008). Monitoring is crucial in the vicinity of injection wells because it can indicate if pressures have exceeded safe levels. Regulatory limits can also be imposed on injection pressures to ensure they are kept at safe levels to avoid induced activity (IPCC, 2005).

On the global scale, the primary long run issue with geologic storage is the potential for leakage to counteract global warming mitigation activities. Therefore, if leakage from storage is too great, the storage's effectiveness diminishes, while also potentially negating other mitigation activities. Even though some leakage will be unavoidable, it is crucial to ensure that the majority of captured carbon dioxide remains securely stored overtime to have a lasting impact (Damen et al., 2006).

While leakage risks are very important to consider, many studies have been conducted to estimate the probability of leakage from geologic sites. Specifically, IPCC evaluated data from natural systems, engineered systems, physical, chemical and mechanical processes, models of CO_2 transport, and results from current geologic storage projects (2005). From these studies, leakage risks appear very low given that the proper storage site is selected.

Three crucial elements that effect leakage potential include: the geological characteristics of a selected storage site and its overall storage system design, the injection system and reservoir engineering, and abandonment methods including well seals. If all of these elements are properly addressed, current evidence suggests, it is likely the fraction of stored CO_2 retained is more than 99% over the first 1000 years (IPCC, 2005). These preliminary results indicate that risks from geologic storage very minimal, as long as proper monitoring techniques are established.

Carbonate Minerals

The mineral carbonation process requires combining CO_2 with metals to form carbonate minerals. The majority of required metals are divalent cations, including calcium (Ca^{2+}), magnesium (Mg^{2+}), and iron (Fe^{2+}). The most abundant source of cations is in silicate minerals. To retrieve these minerals, large scale mining is required. The amount of minerals that would need to be mined is estimated to be larger than the mass of coal used as fuel, by a factor of six (Herzog, 2002; Oelkers et. al, 2008). Similarly, 2-2.6 tons of ultramafic rock would be needed in order to bind one ton of CO_2 (Norman and Storman, 2007). The entire mining process will require environmental alterations including land removal and the storage of silica and carbonates on site. The IEA Greenhouse Gas R and D Program, attempted to address these environmental concerns and concluded that “the methods for mineral storage of carbon dioxide present significant potential for adverse environmental impacts, which are comparable with the issues faced by similar sized modern quarrying/mining operations” (Herzog, 2002). Mineral storage costs should be evaluated using an avoided costs basis because energy intensive processes, such as mineral pretreatment, and environmentally taxing processes, such as mineral mining, most likely have a significantly larger cost per tonne sequestered than cost per tonne if processes were avoided (Herzog, 2002).

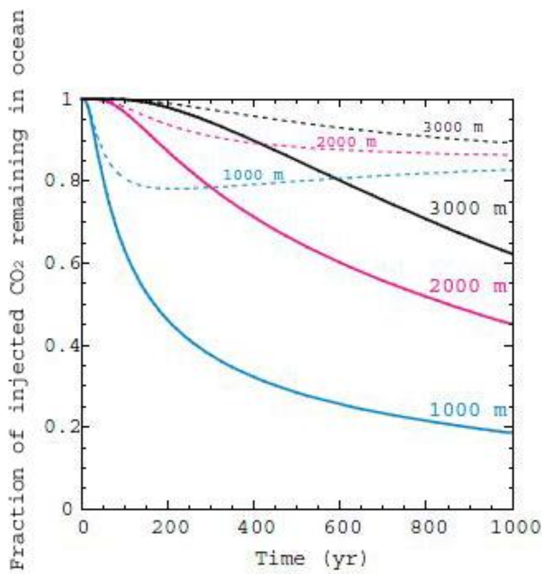
Oceanic

One disadvantage of direct deep-ocean injection is that it may not actually be permanent. Due to ocean currents and local supersaturation, CO_2 could be released back into the atmosphere after a few hundred years. The ocean’s total carbon storage capacity has been estimated between 1000 and 10,000 gigatons (Socolow, 1997), which ostensibly means recent annual anthropogenic emissions of 6.2 gigatons (Davis and Caldeira, 2010) could be stored for roughly 200 to 1500 years.

However, leakages at different depths and rates could take place. Several model results have indicated that retention improves with depth, with retentions of over 70% expected for injections beneath 3000m after 500 years (Orr, 2004; Herzog et al., 2003; Adams and Caldeira, 2008). Even in the near term, when annual leaks of 0.1% are projected at depths beneath 3000m, an injection of 500 gigatons during one century would leak 0.5 gigaton per year (Baer, 2003; Herzog et al., 2003).

Ocean storage under the most favorable conditions simply delays release of a portion of the original CO_2 injection. Figure 12 shows the gradual nature of leakage as the fraction of injected CO_2 remaining in the ocean at three different depths as predicted by a simple ocean carbon-cycle model. Solid lines represent simulation results for injected carbon remaining in the ocean, excluding CO_2 that has leaked to the atmosphere and been reabsorbed by the ocean. Dashed lines represent the amount of injected CO_2 remaining in the ocean, including what has leaked to the atmosphere and been reabsorbed.

Figure 12: Gradual Leakage of CO_2 from Oceanic Storage



Caldeira, 2003

At the lower ocean depths, where injection would likely occur, the environment is extremely stable and physiochemical characteristics scarcely change throughout time. Marine animals' ability to adapt is therefore less vital as is the ability to tolerate severe environmental disturbances, such as a prominent change in pH levels. Increases in CO_2 will lower pH, which could at once alter the productivity of algal and heterotrophic bacterial species, the biological calcification processes, and the metabolism of numerous marine species (IPCC, 2005).

Furthermore, species diversity increases at lower depths while species density decreases, leaving deep-sea populations more vulnerable to extinction than those closer to the surface (Shirayama, 1997). Ocean floor species are especially vulnerable as CO_2 injections intended to form a lake would either prevent species beneath from fleeing or kill those that accidentally entered the area (IPCC, 2005). However, due to anthropogenic CO_2 emissions, the pH of the upper ocean has acidified by -0.1 units. Deep sea carbon injections could possibly reverse the trend (Adams and Caldeira, 2008).

Depth also dictates CO_2 levels prior to injections. Species living near the surface within the intertidal zone may have high resistance to CO_2 due to more consistent exposure, yet species in the open ocean are less exposed and could be more susceptible to increased injections of it. Even in the intertidal zone, however, response to long-term exposure is likely harmful (Shirayama, 2004).

A recent experiment concluded that deep-sea injections could negatively affect the environment, as temperature alone may strongly influence marine animals' CO_2 tolerance. CO_2 injections would take place in the cold temperatures of lower depths, where experiments have revealed that cold temperatures directly lower CO_2 tolerance (Ishimatsu et al., 2008).

Lessened productivity and life spans could accompany ocean storage along with a reduction in biodiversity. The food chain structure may be detrimentally altered, with less food available for higher trophic levels, which would thereby negatively impact the fishing industry (IPCC, 2005).

Without complete knowledge of the consequences of CO_2 release on marine life, this option may not be environmentally sound and could face political challenges (House et al., 2006). The largest challenge for chemically transforming the minerals is the acceleration of the kinetic reactions. Processes that increase it successfully, have not been demonstrated on an industrial scale and as it stands would not be economically feasible (Herzog, 2002).

Storage Cost Analysis

Costs associated with geologic, carbonate mineralization, and oceanic carbon storage processes are discussed below without consideration of the CO_2 source, capture technology, or transport type used. Additional cost analyses presented later in the report include conventional coal and natural gas facilities, as well as low-carbon-alternative plant types such as nuclear, on-shore wind, on-shore wind with NGCC backup, on-shore wind with NGCC backup plus capture technology, off-shore wind, solar thermal, and solar photovoltaic.

Geologic

Much of the technology required for large-scale carbon storage in depleted oil and gas fields already exists, such as drilling and injection techniques, thus potentially decreasing the overall costs of the storage process. The costs of geologic storage of CO_2 are based largely on injection pressure, which determines the amount of electricity needed for the pressurization of CO_2. This figure is a function of injection depth and the formation's pressure profile. In all cases, storage in saline aquifers requires the least amount of pressure, particularly compared to EOR and ECBM (Gielen, 2003). However, storage through EOR and ECBM recovery processes adds another revenue stream to the process, essentially lowering the net costs of the two processes.

Many cost estimates include site appraisal, well drilling and completion, facilities, site closure, well-plugging, and operating costs, such as monitoring, technology, and insurance (IEA, 2009d). Using these estimates, the IEA predicts that a saline storage site receiving 5 $MtCO_2$ each year for 25 years, will cost between \$0.60 and \$4.50 per ton of CO_2. Still, in 2005, the IPCC estimated the cost range to be between \$0.50 and \$8 per ton of CO_2 injected. When combined with EOR, an economic benefit of between \$10 and \$16 per ton of carbon was estimated (IEA, 2005).

Table 3 shows cost estimates for each type of geologic storage in the context of an Integrated Gasification Combined Cycle (IGCC) plant that delivers 7,389 tons of CO_2 per day (Heddle, et al., 2003). They estimated costs from a basecase and found low case and high case costs.

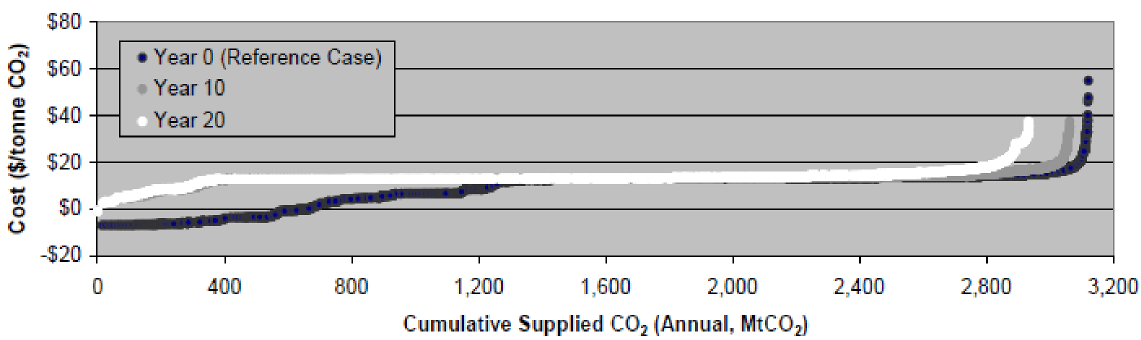
Table 3: Estimated Costs for Each Type of Geologic Storage

Type of Geologic Storage	Cost Range
EOR	$-91.26 - $73.84
ECBM	$-25.72 - $18.88
Depleted gas reservoirs	$1.20 - $19.43
Depleted oil reservoirs	$1.21 - $11.16
Deep saline formations	$1.14 - $11.71

In looking to the future of storage technology, it likely that as storage capacity is reached in less costly reservoirs, such as deep saline formations, storage will move to more costly reservoirs and technologies.

Dooley et al. (2004) used an economic model to predict the influence of higher or lower prices for oil and natural gas on the cost curve of CO_2 storage. While higher prices for energy shift the cost curve down and lower prices shift the curve to the left and upwards, the model showed a modest impact on the cost of using CCS in the long term in either high or low-price energy scenarios, as shown in Figure 13.

Figure 13: Reservoir Filling, Year 0, 10, and 20



Dooley et al., 2004

Carbonate Minerals

Costs associated with mineral storage of include costs of energy and transport of mining materials for a carbonation reactor (although most literature suggests that this would have to be done on site), grinding materials, and heating needs for reactions and storage for byproducts. One study completed by Gerdemann et al., estimated a total price of approximately $54 per ton of CO_2 sequestered (2007). This study considered the reactions of Ca^{2+}, Fe^{2+}, and Mg^{2+} silicate minerals, resources of these minerals, and kinetics for the process (which would have to be greatly improved in order to make the process cost competitive). As Oelkers et al. (2008) point out, this study did not include the scale of operations needed for mineral carbonation using CO_2 from a 1 GW coal fired power plant. This type of operation would entail moving 55,000 tons of material per year. The moving of that material includes mining, transport and storage.

Mineral storage proponents estimate costs at \$70 per tonne of CO_2 sequestered if the reaction processes described above where increased to a larger scale (Herzog, 2002). Costs could be reduced to \$30 per tonne of CO_2 sequestered if problems such as expensive pretreatments and dewatering problems were solved.

The IEA Greenhouse Gas R and D Program Report estimates the cost of current mineral storage processes at \$60-100 per tonne of CO_2 sequestered. One should note that all of these costs estimates are exclusive to only the storage aspect of CCS. These estimates do not include capture and transport (Newall et al., 2002).

An overall cost estimate of CCS according to IEA, averages the options to reduce CO_2 emissions to between \$50 and \$100 per tonne of CO_2 (2009a). The more expensive options would have a cost up to \$200 per tonne CO_2. The R and D and deployment of technologies will require an increase of \$2 trillion and \$2.5 trillion, respectively, before the year 2050.

Oceanic

The cost of the current technology for oceanic storage is estimated to be approximately three to ten times higher than terrestrial geologic storage (House et al., 2006). The IEA Greenhouse Gas R and D Program Report suggests costs for ocean storage at approximately \$1-5 per tonne of CO_2 sequestered; a significantly lower cost estimate than other options such as mineral storage.

Monitoring, Mitigation and Verification

The key components to establish CCS as a successful carbon mitigation technique are being able to determine (1) its effectiveness in capturing CO_2 and (2) reliability in keeping CO_2 stored. Monitoring, mitigation, and verification (MMV) techniques help to assure that CCS is accomplishing its goals and ensure that it does not pose a threat to public health or the environmental. The purpose of CCS is to reduce CO_2 emissions to the atmosphere. MMV techniques must therefore monitor discrepancies throughout the CCS process from the amount of carbon emitted from a source, to the amount captured, and finally, to the amount stored. Furthermore, it must be shown that the amount injected is able to stay in the ground or ocean indefinitely, without leaking back into the atmosphere.

While the entire CCS process can create greater CO_2 emissions by requiring more energy, CO_2 can also be lost through an imperfect capture process, distribution losses through pump stations and points of transfer, and possible leakage from storage sites. The possibility of such leakage events solidifies the importance of MMV technology. A significant amount of the current technology and understanding of geologic storage and its costs, stem from conclusions drawn from the North American field test sites supported by the DOE's Core R and D program. These test sites "contribute towards gaining the knowledge necessary to one day employ [geologic storage] of CO_2 commercially across various geologic and regional settings" (U.S. DOE/NETL, 2009f).

Monitoring technologies developed by DOE's Core R and D program along with the RCSP Program are divided into four monitoring phases reflecting the process of geologic storage: pre-operation, operation, closure, and post-closure phases. In each of these phases different technologies are utilized to "address specific atmospheric, near-surface hydrologic and deep-subsurface monitoring needs" (U.S. DOE/NETL, 2009f). These technologies are further categorized as either primary or secondary technologies. The goal of these programs that monitor CO_2 retention and leakage is to determine the appropriate site-specific combination of protocols and technologies to guarantee 95% retention of stored CO_2 by 2008 (primary) and 99% by 2012 (secondary). These goals are essential to the successful implementation of geologic storage in order to demonstrate to regulatory authorities and to the general public that CCS is a viable, safe, and economically efficient way to reduce atmospheric CO_2 emissions. Furthermore, MMV programs also use modeling to evaluate the possible environmental and human health effects in the event of a leak as well as how to mitigate CO_2 in the event of such a leak (U.S. DOE/NETL, 2009f).

The Frio Brine Pilot in Texas is one of the first Core R & D field test locations to help determine the capacity of brine formations to store CO_2 and also attempts to monitor the subsurface movement of CO_2. Several monitoring techniques are utilized in this location, "including baseline aqueous geochemistry, wireline logging, crosswell seismic, crosswell EM imaging, and vertical seismic profiling (VSP), along with hydrologic testing and surface water and gas monitoring" (U.S. DOE/NETL, 2009f). Knowledge gained from the testing in this location is useful and can be transferred to assist in the preparation of CO_2 storage in similar high-permeability sediments in other various locations within the United States and internationally (U.S. DOE/NETL, 2009f).

The goal of these DOE-sponsored projects is to provide the research that will assist in making CCS a safe and economically viable commercial application for mitigating CO_2 from coal-fired power plants. These projects test a wide range of technologies over various geologic conditions in order to provide a greater understanding of trapping mechanisms and to determine the most effective monitoring techniques and protocols for different circumstances (U.S. DOE/NETL, 2009f). Furthermore, the benefits of these MMV techniques, which work to solidify CCS's place among the commercially viable CO_2 mitigation tools add minimal additional cost to CO_2 storage. According to the IPCC (2005), monitoring costs contribute only an additional $0.01-$0.03 to total storage costs per ton of CO_2 injected in saline formations and depleted oil and gas fields.

Chapter V: Legal and Regulatory Aspects

CCS presents new challenges for the United States legal institution. Crafting a regulatory regime that effectively apportions liability may be especially difficult due to the fact that CO_2, once geologically sequestered, will be in the earth indefinitely. Consequences of geologic storage are not fully understood. Since geologic storage entails permanent isolation of CO_2 from the atmosphere, there may always be some risk associated with CO_2 injection sites (EPA, 2008). Therefore, the primary issue for a body charged with regulating geologic storage is how to assign responsibility for the long-term stewardship of these sites, especially since the required site-monitoring period could far outlast the life of the typical firm. For example, requiring the owner or operator to monitor the site on a permanent and indefinite basis post-injection could discourage investment in CCS technology, while liability rules that are too lax could reduce industry incentive to provide effective monitoring. Complicating the regulators' task is the fact that CCS is a relatively new technology; while the oil and gas industries have been injecting CO_2 as part of enhanced oil recovery operations for decades, CCS operations are still considered experimental and there has been little commercial deployment (IEA, 2005). There has not been enough experience with CCS to collect the type or amount of data that would lend itself to a thorough, broad-scope approach to sorting through the long-term legal complications that CCS presents.

While the short-term liabilities associated with CCS can be placed under existing regulatory structures, the long-term liabilities, on the other hand, do not have an existing legal framework. Therefore, questions have arisen as to how liability should be apportioned for long-term impacts, such as whether to rely on state law or federal law, whether to create new federal statutory law or rely on state common law, and determining which approach offers the most equitable solution for industry and private citizens. This section will address the key concept of liability followed by subsurface property rights. Following that is a discussion of the current regulatory environment followed by short-term and long-term liability. Finally, the EPA's proposed rule for geologic storage is outlined. While not final, this proposed rule can provide valuable insight into the way the agency intends to regulate geologic storage.

Apportionment of Liability for Geologic Storage

Introduction to Liability

Liability is any legal responsibility, duty or obligation. It is the state of one who is bound in law and justice to do something, which may be enforced by action (Lectric Law Library, 2010). The purpose of establishing a liability regime for geologic storage is two-fold. First, geologic storage has risks that require parties to be responsible if damages were to occur. A failure to assign liability for potentially risky activities will result in a lack of accountability, and thus less incentive to protect others from harm. Therefore, the assignment of liability protects individuals or entities from damages resulting from negative externalities by 1) creating a legal responsibility for ones actions and 2) providing remedies for damages such as compensation or an injunction, a court order to perform or stop some action.

Second, a liability regime is essentially a risk indicator for industry. Risk adverse firms would be reluctant to enter a market if the liability for potential risks is unknown or too great.

At the time of this report, the Department of Energy is entering its third phase of experimental geologic storage research, which will study geologic storage on an industry scale (U.S. DOE/NETL, 2010a). Until this research is complete the full extent of the risks involved in large-scale geologic storage will remain unknown. Consequently, in its current state, the market is not ripe for significant commercial scale CCS advancement unless state or federal government offers financial incentives along with a liability threshold to the CCS industry.

The assignment of liability for both the capture and transportation stages can be expanded from existing regulatory frameworks. Injection, however, has few regulatory analogues that mirror the entire range of risks resulting from geologic storage. While EPA's 2008 proposed rule on geologic storage offers some predictability in terms of liability, several risks are not considered. For instance, risk of seismic activity, CO_2 migration underground, and surface leaks remain unaddressed leaving unknowns for industry and a lack of liability for potentially risky activities.

Temporal Issues of Liability

Short-term Liability

Liability for CCS projects can be separated into short and long-term. For the short-term phases of CCS projects, one of the key issues is operational liability, which concerns environmental, health, and safety risks associated with the CCS process. Short-term liability is considered to be less problematic than long-term liability. Many issues regarding operational liability associated with CCS are similar to those already faced by the oil and gas industry. Therefore, the immediate actions necessary for regulating CCS primarily concern long-term liability (Robertson et al., 2006).

Long-term Liability

Most CCS research considers the period of long-term liability to begin anywhere from 50 to 200 plus years after site closure. There are three primary types of long-term liability for CCS projects: environmental, in situ, and trans-national. Environmental liability, also called climate liability, is associated with leakage from geologic storage reservoirs. In situ liability is associated with public health risks and environmental or ecosystem damage caused by CO_2 leakage or migration resulting from the various phases of CCS operation. Trans-national liability issues can be evoked when CCS projects affect more than one country such as projects employing offshore storage, involving CO_2 migration across national boundaries from original source reservoirs, or situations in which leakage can affect global climate (U.S. DOE/NETL, 2006).

The Challenges of Assigning Long-term Liability

There are three main challenges associated with liability assignment. The first challenge concerns the difficulty of detecting CO_2 leakage and assigning responsibility for damage resulting from the injection of CO_2. Also, it will be difficult for a plaintiff to pinpoint the source of the problem if there were several possible sources. These issues will rely on technical solutions, such as post-closure monitoring that is well tailored to the characteristics of the site (Benson et al., 2004). Moreover, if a single operator is responsible for ensuring the integrity of the storage facility, the multiple-source issue will not be a problem.

A second challenge presented by the assignment of liability involves the length of time between cause and effect. For example, there could be an extended latency period before any underground seepage or surface leaks occur. There are several problems that may arise as a result of this latency period. Not only does it decrease the operator's incentive to ensure the long-term integrity of the storage facility, but the responsible party may no longer be able to address the damage by the time the problem arises (U.S. DOE/NETL, 2006).

A third challenge is the significant financial cost associated with remediation. It may not be possible for a firm to adequately rectify damages resulting from its CCS operations. In the event that an operator goes bankrupt, there will be no funds available to continue site monitoring and maintenance, or to address any problems that subsequently arise from the project. This can be a serious problem in cases where firms become insolvent as a result of their financial responsibility for environmental or safety mishaps (U.S. DOE/NETL, 2006). Furthermore, since the risk associated with CCS has not been thoroughly quantified, it may be difficult for projects to acquire the appropriate insurance.

In the long run, the respective legal responsibility of CCS operators as well as federal and state governments may be interrelated, as long-term liabilities could eventually become government responsibilities after the contractual lifetime of a project. Thus, setting up the procedures or guidelines for determining the lifetime of a project is very important. If responsibility for CCS risks does transfer from the private to the public sector after a specified period of time, determining when this switch will happen is critical for the development of the CCS legal framework.

Challenges of Addressing Liability for Geologic Storage

Liability is clear in that it assigns responsibility for potentially damaging activities. What is less clear, however, is the method(s) to be chosen to assign liability for the risks not addressed in the EPA's proposed rule on geologic storage. The proposed rule indicates EPA's intention to regulate site selection, area of review, well construction, monitoring, and post-closure care of CO_2 injection wells (EPA, 2008). Despite its comprehensiveness, the Safe Drinking Water Act (SDWA), the framework for the proposed rule, is not comprehensive in the authority it provides the EPA to regulate geologic storage. The purpose of the SDWA is to protect public health by regulating the nation's drinking water supply through activities that protect drinking water and its sources (EPA, 2004). Other sources of harm from geologic storage such as surface leaks of CO_2, migration of CO_2 from its designated formation, and induced seismicity are left unaddressed under existing federal statutes. The result is less protection from geologic storage activities that may result in damages associated with public health impacts, property disputes, and environmental damage (Heinrich, 2003).

Establishing a Liability Regime for Geologic Storage

EPA's final rule governing geologic storage, once promulgated, will dictate the actions taken by industry and the states as well as the protections awarded to private citizens. The proposed rule does not address certain risks associated with geologic storage and may allow states to retain primacy over these risks. However, as more research becomes available the EPA may decide to draft additional legislation to cover those risks. At this stage in the development of geologic storage, two scenarios are important to consider: 1) state primacy in the absence of federal legislation and 2) new federal legislation covering the liability for the unaddressed risks.

Responsibility for the geologic storage risks not addressed in EPA's proposed rule can be apportioned in one of two ways – either through statutory or common law. While private insurance has been considered as a tool to manage liability, this section is limited to the role of government. Both the federal and state governments may create statutory law by enacting legislation. The federal government, however, is in a much better situation to deal with the unaddressed risks statutorily. The SDWA is an established framework that the EPA plans on using to regulate geologic storage. Therefore, any additional risks not addressed under the Act could potentially be added to it, thereby increasing the authority granted to the EPA. Additionally, if the states chose to codify their own legislation for the unaddressed risks, they would have to start from scratch, resulting in high transaction costs. In the absence of additional federal legislation to cover the risks, state authority and the common law system will address liability. This system relies on previous case decisions that are applied to present cases with similar facts. For the purposes of this paper, then, the term 'legislation' refers to federal action and 'common law' will refer to state primacy in the absence of federal action concerning the unaddressed risks of geologic storage.

The method chosen to apportion liability for the remaining risks, whether through federal legislation or state common law, will affect two issues: 1) the extent of redress granted to individuals that have experienced damages and 2) the effect of liability on industry. Ideally, a liability regime would provide maximum protection to individuals while fostering the most advantageous economic environment for geologic storage operations. Ultimately, the method chosen to assign liability should attempt to balance the interests of both geologic storage developers and private citizens.

Common Law Approach to Apportioning Liability

In the absence of federal legislation, the state common law system could become the primary method of apportioning liability for the risks associated with geologic storage. Common law is uncodified and relies on previous case precedent to make decisions regarding liability. Both the states and the federal government may choose a common law approach; however, states tend to dominate common law application. Common law differs from statutes in terms of the intent. Statutes are created to assign liability for specific activities that result in specific externalities whereas common law covers a broader range of legal issues and is not bounded by a particular situation, such as clean air or water.

The finding of liability for damages under common law depends on the outcome of similar cases in the same jurisdiction. Additionally, lower courts are bounded by decisions made by higher courts. Common law encompasses broad areas of law such as property, contract, and tort law (Wilson, 2007). Of primary concern in the case of injected CO_2 is tort law, which is the body of law that allows private parties to obtain relief from the person or entity who caused an injury (Duhaime, 2009). In the absence of a statute, it is tort law that protects the public from damages. Torts are brought to court through "causes of action," which is the act that resulted in damages. Causes of action can include trespass, negligence, nuisance, and strict liability with potential remedies being monetary or injunctive relief (Duhaime, 2009). Unlike contract law, tort law does not require an agreement between the two parties. This is important because an individual that is injured by injection of CO_2 does not have an agreement with the party that injured them. Under tort law a private citizen can obtain compensation in the form of monetary and or injunctive relief for damage to oneself or property.

Statute Approach to Apportioning Liability

As mentioned previously, the EPA's proposed rule already identities the underground injection control program framework under the SDWA as desirable for regulating injected CO_2. If the risks that remain unaddressed in the proposed rule are to be addressed within the final rule, new legislation adding to the SDWA will be required. In this case, new legislation would explicitly mandate that certain activities take place to reduce the risks. A failure to comply with the mandate may result in a court injunction to comply or criminal sanctions. Assigning liability for activities through legislative mandates changes the way industry operates.

The ability for private citizens to seek redress for a cause of action is dependent on a citizen suit provision within the statute. A citizen suit provision allows private citizens to file a lawsuit against industry for engaging in conduct prohibited under the statute. A common remedy may include an injunction. Most federal government environmental statutes contain citizen suit provisions. Under the SDWA, for example, a citizen is allowed to file a lawsuit if the EPA fails to act within 60 days from the date of notice. If successful, the citizens are entitled to compensation for legal fees, but any further pecuniary award is not applicable under the statute (EPA, 2010).

Recommendations for Assigning Liability

While a common law approach to apportioning liability is important for state sovereignty, it may impede the development of the CCS industry. Each state differs in its approach to common law. This inconsistency is not attractive to the development of any large-scale industry, including CCS. For example, as the CO_2 reservoir extends beyond state borders, a geologic storage operator would be concerned about the difference in law between the states. Unless neighboring states create a similar common law system, a geologic storage operator would incur significant transaction costs in order to comply with the differing laws. Furthermore, case precedents are less explicit in their assignment of liability, leaving unknowns for industry. Case precedents can also be overturned adding to the unpredictability of the common law approach. Therefore the extent that case precedent can be used to assign liability for all the risks discussed here is difficult to determine. As a result, knowledge of the extent and apportionment of liability to industry is less predictable, and consequently less attractive to industry.

In addition to the potential that common law may impede the development of the CCS industry, this form of law may not provide more protection than a statute approach to apportioning liability. A common law cause of action carries a high burden of proof on the plaintiff who has experienced damages. In the case of geologic storage, that burden of proof may result in high transaction costs. For example, a trespass cause of action, in the case of CO_2 underground migration, requires that one prove an intentional and unauthorized physical entry of the CO_2 and that the entry caused harm. Under a nuisance claim, a plaintiff must prove a substantial interference with the use and enjoyment of one's property. Under a negligence cause of action one must prove that a defendant had a duty of care, a breach of that duty by unreasonable conduct occurred, harm was caused by that breach of duty, and that damages resulted from the harm (Figueiredo, 2007a). The issue is that subsurface pore space is not accessible except through drilling apparatus. And while modeling can be used to determine risks, the proof of actual harm, or even migration of CO_2 for that matter, is made much more difficult underground. Therefore proving a cause of action involving the subsurface could be more difficult under common law. In contrast, the burden of proof is less of an issue on the surface where damages can easily be assessed and linkages are more easily understood.

The statute approach has the potential to provide greater benefits to industry as well as private citizens. By adding legislation to the SDWA to include the unaddressed risks, industry would benefit from an explicit liability regime in which most of the risks can be accounted for in the production function. Such an approach would therefore facilitate development. Another benefit of a statute approach is that it lessens the transactions costs for private citizens. Bringing suit against an entity for damaging the subsurface may result in high transaction costs for private citizens. Under a statute approach, however, the burden placed on private citizens is reduced compared to the common law approach. A citizen must prove harm and proof that the statute was violated. Therefore, the less a citizen needs to prove, the lower the transaction cost to that individual. Under the statute approach, however, injunctive relief is the only means of redress available to the citizens. While the ability to acquire compensation would seal the deal for comprehensive federal legislation, the need to provide for monetary compensation is not as necessary for the subsurface. Unlike the surface, the subsurface is used much less often, therefore, making monetary relief less necessary.

Approaches to liability apportionment represent a dynamic process. Ultimately, the regime chosen must be equitable in providing private citizens rights for redress in addition to avoiding high costs on industry that would prevent the development of CO_2 storage technology.

Current Legal Framework

While the oil and gas industries have been injecting CO_2 as part of enhanced oil recovery for decades, the geologic storage of CO_2 as part of CCS is still a relatively new concept. As such, a comprehensive legal framework has not yet been developed to deal with the short-term risks presented by CCS projects. Short-term risks are those that occur during the operational stages of a CCS project, or during the period between the commencement of the project and the point at which the firm stops injecting CO_2. The primary operational stages are transportation, injection, and post-injection storage prior to injection cessation. As previously indicated, until proposed legislation is passed, existing laws, including those that regulate underground injection and pipeline transport of other materials, could provide some measure of regulation.

Recent developments have laid the foundation for federal regulation of CO_2 emissions. In April 2007, in *Massachusetts v. EPA*, the Supreme Court ruled that the EPA must regulate CO_2 under the Clean Air Act, if a review of the scientific evidence proved that CO_2 emissions pose a risk to public health and welfare. In December 2009, the EPA finalized its endangerment finding, stating that the CO_2 and other GHGs brought under scrutiny by *Massachusetts v. EPA* do indeed threaten health and welfare, and therefore, can be regulated by the EPA under the Clean Air Act (Walsh, 2009). The endangerment finding announcement is a landmark development for organizations concerned about the harmful effects of CO_2 on the environment, and paves the way for future legislation that would limit CO_2 emissions. If this legislation calls for energy producers to cut their CO_2 output or face large penalties, CCS becomes a viable and possibly essential part of any large-scale effort to reduce emissions.

Both the federal and state governments can potentially regulate CO_2. Currently, there are no federal laws regulating any stage of the CCS process, including capture, transport, injection, and post-injection storage. However, current federal legislation regulating interstate pipelines and underground injection wells is fairly comprehensive and components of this legal framework could be used to regulate CCS. Additionally, some states have crafted their own legislation to regulate the capture, transport, and injection activities undertaken by the oil and gas industries. These state laws are also potentially applicable to CCS. The matrix of state and federal laws that apply to CCS activities may create a complicated and burdensome task for regulators. The distribution of authority between the federal government and the states, respectively, will be a fundamental issue to resolve when crafting a workable regulatory framework (IEA, 2005).

Several state and federal laws currently regulate the underground transport of gas and liquid fuels. These laws could be used to regulate CO_2 transport until a legal framework is designed to address the risks posed by CCS. The siting of pipelines that transport CO_2 to EOR sites are typically regulated by state law; however, if these pipelines cross federal land, the Bureau of Land Management has jurisdiction over pipeline placement under both the Federal Land Policy and Management Act and the Mineral Leasing Act. The Federal Energy Regultory Commission (FERC) influences siting as well as the rate companies can eventually charge for energy produced using EOR, and the Department of Transportation monitors the safety of fuel transport under the Hazardous Liquid Pipeline Act. It is reasonable to assume that these agencies and the laws by which they operate would also apply to the transport of CO_2 for CCS projects, and, in the case of FERC, the rate charged for energy whose production involves CCS. However, laws that were originally created to regulate gases and liquid fuels cannot be expected to adequately substitute, on a long-term basis, for legislation created specifically for CCS. Federal legislative action addressing CCS is needed (Mack et al., 2009).

There are several federal provisions that could potentially regulate the CO_2 storage that takes place during the operational life of a CCS project. These provisions are found in the Safe Drinking Water Act (SDWA) of 1974. The SDWA requires the EPA to oversee state monitoring of drinking water quality and to enforce minimum federal drinking water quality standards. While states generally enforce the provisions of the SDWA within their respective boundaries, the EPA can assume enforcement responsibility if state's actions are inadequate. The SDWA houses the Underground Injection Control Program (UIC), which protects underground sources of drinking water (USDW) from contamination by injection wells. The UIC also standardizes the injection of all fluids, including liquids, gases, and slurries (Figueiredo, 2007b). The EPA is currently working on an amendment to the UIC that would protect USDWs from contamination by geologically sequestered CO_2.

Geologically sequestered CO_2 may also be subject to provisions contained in the Resource Conservation and Recovery Act (RCRA), under which the EPA monitors the treatment and storage of hazardous waste. In response to public inquiry, the EPA is currently considering if and how it will regulate injected CO_2 under both the SDWA and the RCRA. In order to avoid regulatory overlap, the EPA may decide to issue "conditional exemptions" to RCRA's requirements (EPA, 2004). The proposed rule regarding how EPA plans to divide regulatory authority between the SDWA and the RCRA is expected in September 2010.

The current legal and regulatory framework for the capture and transportation of other materials is analogous to CCS and could be used to address most risks, at least in the short term. CO_2 storage, however, lacks a sufficient liability framework of its own. Comprehensive federal legislation that includes CO_2 storage would provide a reliable framework for companies interested in developing CCS projects. However, under this approach, the federal government would likely preempt existing state laws that conflict with federal laws.

Environmental Protection Agency Proposed Rule for Geologic Storage

Given the growing concern about resource scarcity and the current political emphasis on achieving greater energy independence, CCS is poised to become an important technology in the effort to mitigate climate change while still meeting increasing energy demands. In anticipation of increased deployment of CCS technology, the EPA has issued a proposed rule for the regulation of geologic storage of CO_2. This proposed rule is extensive in scope and comprehensive in its approach. If the final rule resembles the proposed rule, it will play a key role in regulating the various legalities associated with the long-term storage of CO_2.

Therefore, this section examines the portions of the rule that are most relevant to long-term liability concerns and analyses their applicability to future CCS projects.

The EPA's proposed rule would regulate CO_2 geologic storage under the UIC program, contained within the SDWA. The UIC program currently delineates five classes that specify different well requirements and the type of fluid most appropriate for each class. The proposed rule would create a sixth category of well designed specifically to receive injected CO_2. Currently, geologic storage of CO_2 is carried out under the Class II and Class V categories of the UIC. Since the UIC is contained within the SWDA, the primary focus of the new CCS regulation would be the protection of underground sources of drinking water (USDW) from contamination by injected CO_2. Although the focus on USDWs precludes the EPA from specifically addressing other long-term risks induced by CO_2 injection, such as potential damage to the ecosystem or risks to public health, the proposed rule creates a "net" of regulation that promises to tangentially address other risks posed by CCS. In other words, assuring that CO_2 storage is executed properly and so as not to endanger USDW will also ensure that other potential problems are avoided. For example, the proposed rule requires the owner/operator to properly plug all on-site wells and perform adequate post-injection monitoring; such provisions would also ensure that CO_2 does not migrate to the land's surface, where it could endanger human health and negatively impact ecosystem functioning (EPA, 2008).

Long-term responsibility for CCS sites is rooted in the documentation that the prospective owner/operator must submit before injection even begins. The documentation must specify the parameters of the area in which injection will take place and provide a detailed assessment of the geological formation into which the CO_2 will be injected, computational models of the injection area, mechanical details of the actual injection operation, emergency procedures, and a post-injection site monitoring plan. Solidifying the CCS project's details prior to its operational stage is important, because the initial plan will serve as a base of reference for interactions between the EPA and the owner/operator over the duration of the project. The plan acts as a continuous-feedback model, in that the EPA requires that changes made to the project be incorporated into the model and the model reconfigured to account for these changes (EPA, 2008). The preliminary post-closure plan ensures that the owner/operator will be able to properly close the site earlier than scheduled in the event of unforeseen problems or complications.

The proposed rule focuses on requirements for the post-injection site care plan that the owner/operator must submit to the Director at the time of the initial permit application. The plan must include information on the geological position of and pressure induced by the CO_2 plume at the time of injection cessation, as well as the post-closure monitoring schedule, a description of monitoring activities, and location of monitoring sites. At the actual time of closure, the operator must either demonstrate to the Director that the original plan is still adequate or modify the plan to reflect changes made to the operation during the injection period (EPA, 2008). The initial post-injection plan is an important component of the project, because it sets the stage for those site maintenance and monitoring activities that the EPA will require the owner/operator to perform. It also specifies the scope of responsibility for the CCS operation, at least during the immediate post-injection period.

A second essential component of the rule's post-injection proposed requirements is determining the period of time for which the original owner/operator will be legally and financially responsible for the site. According to the proposed rule, many environmental programs use 30 years as the default liability period. However, because of the unique physical properties of CO_2, the EPA has determined that owner/operator liability should extend at least 50 years past the time of injection cessation. The proposed rule also recommends a performance component, whereby the Director could lengthen or shorten the period of liability at his/her discretion. If the owner can demonstrate that the site no longer endangers USDWs, he or she may request that the Director authorize site closure before the 50-year period is complete; conversely, the Director may lengthen the period of liability beyond 50 years if the owner cannot prove that the site does not poses a threat to USDWs. EPA considered several factors before arriving at this hybrid solution. First, the potential for migration of the CO_2 plume beyond its originally projected boundaries is greater than for other injected fluids, due to the buoyancy and viscosity of CO_2 and the pressure required to inject it. Second, the risks associated with geologic storage of CO_2 are highly site-specific, making the designation of a generic default liability period inadvisable. Post-injection monitoring procedures should be crafted and implemented on a case-by-case basis. This is important to account for the unique features of each operation and the specificities of the geological formation, as well as the relative newness of CO_2 geologic storage technology itself. Furthermore, the proposed rule would require that owners/operators demonstrate the financial capability to perform post-injection maintenance and monitoring at the outset of the operation (EPA, 2008).

The timeframe specified as part of the rule's post-injection requirements represents a compromise between two options. A liability period that is too short could result in damages from improperly maintained or remediated geologic storage sites; one that is too long could require owner/operators to expend significant resources on needless site maintenance and monitoring. Studies cited in the proposed rule claim that CO_2 plumes generally stabilize within 10 to 100 years of injection cessation (EPA, 2008). The 50-year rule strikes in the middle of this range, giving the EPA a comfortable margin of safety on the lower end while allowing owners/operators to avoid unnecessary site responsibility on the higher end. The performance component, whereby the Director can lengthen or shorten the timeframe, is meant to account for uncertainty over the appropriate amount of time to require owner/operators to retain legal responsibility for the site and engage in maintenance and monitoring. The performance component is basically a tool that the EPA can use to tailor the 50-year liability period to fit the specific features of a given CO_2 geologic storage operation, so that efficiency is maximized and waste is reduced.

Perhaps most importantly, under the current proposed rule, owners/operators of geologic storage sites would not be financially responsible for site monitoring or remediation "after the post-injection site care period has ended and the Director has authorized site closure" (EPA, 2008). However, given the final rule would regulate CO_2 geologic storage under the SDWA, Director-authorized site closure does not exempt owners/operators from liability for future problems resulting from the operation, such as negative public health effects or ecosystem damage, that are unrelated to USDWs (EPA, 2008).

Legal Constraints of Subsurface Property Rights

The injection of CO_2 for geologic storage has raised questions as to whether the existing property rights regime in the U.S. is sufficient for advancing the industry's development. Two issues dominate the literature regarding the existing regime – acquisition of property rights and differing state laws. The proposed CO_2 reservoirs are expansive and therefore project developers will encounter many property interests including interests in the surface, subsurface, and minerals. These rights will have to be acquired before geologic storage operations can proceed. In the absence of geologic storage specific property legislation, however, each property right must be acquired through voluntary means. This approach, some argue, is likely to result in significant transaction costs for geologic storage developers.

In addition to issues of property acquisition, geologic storage developers face a federal system in which state laws are not in harmony. Traditionally the states have authority over the allocation of property rights, and each state differs in its approach. Therefore, in the likely event that a CO_2 reservoir crosses state boundaries, project developers will have to abide by a mix of state laws. Undoubtedly, this would complicate the development process.

A third issue involving is that the existing property rights regime in the U.S. can be viewed as an impediment to geologic storage development. However, private property rights provide valuable benefits to land owners by protecting them from activities that interfere with reasonable use or damage to their property. It is important, then, to consider geologic storage development from the private property owner's perspective in addition to the industry perspective.

Current Property Rights Regime in the U.S.

Background

In the U.S., property rights are managed by the states with rules governing access, ownership, and transfer of property varying considerably by state jurisdiction. Generally, two options for assigning subsurface rights are considered by the states: 1) sever the subsurface and surface rights or 2) assign subsurface rights to the surface owner in a fee simple ownership. Overtime most states have adopted what has been referred to as the "American Rule," which grants ownership of the subsurface geological formation to the surface owner. Several states have begun to assign pore space rights specifically for geologic storage. For example, Wyoming, North Dakota, and Montana have created statutes that designate pore space ownership to the surface owner (CCSReg Project 2008). These proactive states, however, could be preempted with federal legislation should the federal government decide to take an active role in assigning property rights for geologic storage. It should be noted that ownership of the geologic formation usually excludes mineral rights. That is, the mineral rights may be "severed" from the surface rights. In the case of severance, the owner of the mineral rights still has a property interest in exploring for and removing minerals (Figueiredo, 2005).

Property interests that need to be acquired for geologic storage are a function of: 1) whether the reservoir is depleted of minerals and 2) whether the mineral interest has been severed from the surface (Figueiredo, 2005). Under the conditions that a severance has not occurred, the surface interest only needs to be acquired since the mineral interest is explicitly attached in the deed. However, under the condition that a severance has occurred, it needs to be determined whether the minerals have been depleted. If mineral depletion has occurred only the surface interest needs to be acquired. If minerals are still present, then both the surface interest and mineral interest needs to be acquired.

Relevance to Geologic Storage Developers

Progressive states have codified geologic storage legislation granting subsurface rights to the surface owner. Under this legal regime, geologic storage developers need only acquire the surface rights, since the subsurface rights are included in a fee simple ownership. The condition of mineral rights would likely differ by state. While this system makes acquisition much easier for geologic storage developers, it will only benefit the industry if states with connected reservoirs have similar laws. Otherwise, geologic storage developers will be faced with a patchwork of legal arrangements.

Even if the states create a comprehensive and cohesive property rights regime, geologic storage developers are still likely to run into high transaction costs for property acquisitions. Under the current system, acquisition of property interests for geologic storage must occur through market transactions between buyer and seller. For a typical geologic storage reservoir, the number of acquisitions could reach into the thousands. Additionally, there is a likelihood of "hold outs," where the property owner waits until the price rises before selling. States could, however, take an advanced step by crafting geologic storage legislation allowing for the condemnation and or unitization of the subsurface. This intervention into the market eases the burden of acquiring hundreds or thousands of rights by condemning the property as part of the public good. This assumes, however, that geologic storage of CO_2 is considered to be in the public interest. If so, more options for acquiring property become available.

Relevance to the States

While the current property rights regime may pose some challenges for geologic storage development, the states benefit from retaining the authority and thus flexibility for making decisions for the good of its own citizenry. If a state has a powerful mineral interest due to vast mineral deposits, the potential conflict geologic storage poses to those interests may deter its development. However, if a state has a subsurface that contains less valuable or worthless material, geologic storage may gain acceptance as a desirable use of the subsurface. As mentioned, a consistent legal framework is needed for geologic storage development, at least on a regional level. The future of state property rights for geologic storage then will depend on whether states can coordinate their property laws for carbon storage. For example, compacts in which states agree on a regional approach to dealing with property rights would result in a much-needed consistent regime for industry. Western states have a spatial advantage in that storage reservoirs will cross fewer state boundaries, and thus fewer states will need to come to an agreement. Eastern states, because of their density, will have storage reservoirs that span many states. Therefore, extensive cooperation will be needed for the eastern states to agree on a regional approach. Consequently, eastern states are more likely to require federal intervention to create a consistent property rights regime.

Under the current property rights regime states would continue to have the flexibility to change laws to either promote geologic storage development or impede it. For example, those states that have already codified statutes for geologic storage property rights are doing so because they want to foster an environment that creates certainty for the CCS industry or to protect the mineral interest. States that enact such legislation will most likely set a precedent for other states to follow or possibly influence the EPA decisions to regulate property rights. On the downside, state flexibility for property rights subject to a race-to-the-bottom. A race-to-the-bottom occurs when states set minimal standards in order to attract economic development. For example, a state could transfer liability for subsurface trespass of CO_2 to the public, thus lessening the burden on industry. Industry, in this case, may take fewer safeguards to prevent damages from occurring. Such a move by the state would do plenty to attract industry; however, the public would lose if a tragic event caused widespread damages in which the public would incur the costs. Additionally, the more liability the public incurs, the more likely innovation will be stifled. Whatever approach the states take, there is little doubt that time is limited. The EPA plans on promulgating its final rule by 2011 or 2012, leaving little time for state cooperation.

Relevance to Private Property Owners

Under the existing property rights regime, owners maintain the ultimate authority over their land. Any request from geologic storage developers for acquisition would take place through normal market transactions in which the owner is compensated as they see fit. Property owners continue to be protected under common law torts in the event of a subsurface trespass. In the end, the decision to sell or not to sell is up the landowner.

Government Intervention of Property Rights

Given the interstate nature of geologic storage the federal government may regulate property rights for this purpose. If the states cannot agree on a comprehensive and cohesive property rights regime government intervention may be necessary for the good of the public interest. It could be argued that geologic storage of CO_2 is in the public interest, thus opening the door for. The oil and gas industry, utilizing the public interest argument, gained the power of government backed unitization and eminent domain. Unitization in the oil and gas industry is the grouping of oil or gas field leases for resource development that create a consistent field-wide operation. It is a means by which developers can work together in order to maximize the efficiency of the well. Unitization statutes are often accompanied by a "compulsory joinder of interest" clause, which allows for unitization to take place once a certain percentage of owners agree to a deal. The remaining owners, or "hold outs," are subject eminent domain.

Eminent domain, or condemnation, is the power possessed by the state or federal government to appropriate land for public use (Larson, 2007). In the case of eminent domain, the private right holder must receive at least fair market value for their property. If not, then the act constitutes a "taking" within the meaning of the Fifth Amendment of the U.S. Constitution. If geologic storage of CO_2 is found to be in the public interest, the state or federal governments could create unitization and eminent domain legislation for purposes of subsurface acquisition. In doing so, geologic storage developers can acquire property rights at reduced transaction costs. Without this legislation, geologic storage developers would be forced to acquire each property right separately at variable costs and over a longer period of time.

While the states have the authority to grant both unitization and eminent domain, they would have to agree on a consistent approach. If not, a comprehensive federal approach may preempt the states. For example, if a geologic storage reservoir spans two states and one state authorizes the use of unitization or eminent domain to acquire property rights for geologic storage, but the neighboring state does not, this inconsistent approach will impede industry development.

Federal Ownership of Pore Space

In the event that the states cannot agree on a consistent legal regime for property rights, the federal government has the option of acquiring pore space rights for geologic storage to the public good. Under this scenario, only the portion of the subsurface that stores carbon would be under federal ownership, while the state would maintain the mineral rights. Since the government owns the pore space, a permit would be required to characterize a site for geologic storage of CO_2, which is likely to be a less costly option.

Chapter VI: Public Perception and Acceptance

Public perception could play a substantial role in the success of CCS policy. Similar to electicity generating plant site selection, CCS projects will require community stakeholders and general public acceptance (Nugent, 2001; Parfomak, 2009). In contrast to broader power plant issues, CCS's need for geologic storage sites on public and private property means that public opinion will have an even greater potential to either help or hinder its development (Bachu, 2008).

In order to encourage that public perception help CCS development, some suggest employing a social site characterization along with the required technical characterization of the storage site. This is a process in which the company proposing the CCS facility seeks to understand who the relevant stakeholders are, how the local community perceives risks, what experiences the local community has with these types of facilities, and how strong the media presence is (Wade and Greenberg, 2009). This section of the report seeks to support this recommendation along with two others:

1. Organize public information campaigns using multimedia to provide facts and figures regarding CCS development in each region; and
2. Discuss CCS as an option in a portfolio of carbon management strategies, providing proportional information on CO_2 mitigation and public funding.

Role and Influence of the Public

The role and influence of the public and stakeholders is vital when considering the implementation of CCS technologies. The unit of analysis can range from the individual citizens to local coalitions and regional movements. The following paragraphs provide real-world examples of the type of influence the public has had on CCS implementation.

The first example is a success story at the FutureGen site in Mattoon, Illinois. FutureGen Alliance is a public-private partnership established between the DOE and a coalition of coal producers in order to test and demonstrate the technologies necessary to fully implement CCS. The FutureGen project includes construction of an IGCC power plant with post-combustion capture. In selecting the site to build FutureGen, DOE used a competitive selection process that allowed different sites to bid for the project. In the end, seven states turned in bids for 12 potential sites, with four selected as semi-finalists before DOE finally chose Mattoon, Illinois (Bielicki and Stephens, 2008).

According to the Illinois State Geological Survey, the public's response to the FutureGen project was overall very positive because of increased public engagement through a state-wide CCS awareness campaign. The public viewed the project as a potential source of economic development for the state of Illinois, due to the high prevalence of saline aquifers that are perfect for deep saline geologic storage found throughout the region. They saw both an opportunity to revive the struggling state coal industry and to bring researchers and scholars to the newly developed world-class research facility (Bielicki and Stephens, 2008).

The media in the Mattoon community has continued to portray the FutureGen project in a positive light, which, in addition to the competitive site selection process, has helped keep public opposition at bay (Bielicki and Stephens, 2008). When federal funding was pulled due to a cost overrun in 2008, the Alliance members nevertheless continued working hard to see the project come to fruition (Biello, 2008; Buchsbaum, 2008). In 2009, DOE reached an agreement with alliance members to recommence the project. This showed that positive attitudes of industry representatives, local and state government officials, and Illinois citizens can keep a project alive that otherwise would have been abandoned (FutureGen, 2009).

However, there are a number of examples that offer precautionary tales of the consequences of a misinformed and oppositional public. One is the failed PurGen plant proposal for Linden, New Jersey (Applebome, 2009). This project proposed a 750 MW pulverized coal plant with post-combustion capture technology and oceanic storage. A number of environmental groups including the Sierra Club, Edison Wetlands Association, New Jersey Environmental Federation, and others formed a new coalition called the Arthur Kill Watershed Alliance to oppose the plan. The Linden Council voted down a memorandum for the plant which further encouraged the environmental groups prompting them to declare a win for public health, the environment, and renewable energy (Green Jersey, 2009).

Even though the carbon dioxide would have been pumped underground through a 100 mile pipeline for storage 70 miles off the New Jersey shoreline, the environmental groups found reasons to oppose it (Green Jersey, 2009). Former N.J. DEP commissioner Bradley Campbell is a consultant on the project and warned that environmental groups should learn to compromise. "One of the difficult challenges that climate change presents is that environmental groups are very good at opposing projects, and not very good at making compromises in supporting projects," he told the New York Times. "We need to get beyond the mind-set that there's a perfect alternative if we ever hope to avoid the worst impacts of climate change" (Applebome, 2009).

Another example of public skepticism is the Twin River Energy Facility, a proposed coal and wood gasification plant in Wiscasset, Maine. In this case, an educational campaign helped gain public acceptance for CCS in general, but mismatch between the developer and local stakeholders led to further distrust of storage on site within the community. Developers chose this site due to the community's existing infrastructure from a nuclear power plant that once operated in the area (Bielicki and Stephens, 2008).

The Chewonki Foundation, a local environmental education nonprofit organization, organized a seminar on CCS in order to educate the community on the role the technology may potentially play in the Wiscasset community. This seminar gave the community members an opportunity to ask questions and interact with experts on CCS. In a survey taken after the seminar, participants reported that their support for CCS increased because of what they learned throughout the seminar; however, their concerns about the technology remained the same. The resulting consensus is that Wiscasset citizens support CCS as a part of a larger carbon mitigation strategy with the understanding that there is no potential for carbon dioxide storage in or near Maine (Bielicki and Stephens, 2008).

Current Public Perception

According to a 2003 study by the MIT Laboratory for Energy and the Environment, the American public knows little about mitigating global climate change or CCS technology (Curry et al., 2004). A follow-up study in 2006, however, showed that the American public's awareness of the problem of global climate change and their willingness to pay for solutions increased 50%. Despite these increases over the three-year time span between studies, researchers found that the overall knowledge of available solutions had remained unchanged (Curry et al., 2007).

The 2006 study questioned a pool of 1,596 people, with demographics representative of the United States as a whole, in order to reveal the public's comprehension of carbon capture and storage in terms of the environment and energy generation. Responses revealed that respondents rank the environment eleventh out of twenty-two overall issues, and within this category, rank global warming first out of ten. This ranking is improvement change from the 2003 survey results that place the environment 13 out of 22 and global warming sixth out of the ten environmental issues listed. The survey also divulged that a large majority of the respondents were unaware of the existence of CCS and carbon storage, particularly when these technologies were described using these names. However, people have a tendency to exaggerate their recognition of items in order to provide what they expect to be the desired response. Therefore, the actual recognition rates of CCS among survey respondents may in fact be lower than the numbers reported (Curry et al., 2007).

In order to learn respondents' willingness to pay to solve climate change, they were asked how much each would be willing to pay every month in addition to their normal electric bill ($5, $10, $25, $50, or $100). What researchers found was that individuals had an average willingness-to-pay of an additional $14 per month, an increase from the 2003 result of $6.50 per month (Curry et al., 2003, 2007). In a follow up question, researchers provided the same individuals with information regarding the cost of various sources of energy (see Appendix A) and asked the same willingness-to-pay question. The results showed that there exists a maximum willingness-to-pay for curbing carbon emissions and global warming. Based on the results, researchers concluded that they expect public support to decline if people became aware of the large discrepancies in price and there exists an option to choose a cheaper electrical source (Curry et al., 2003). Interestingly, the public's support for CCS as a carbon mitigation strategy declined from 6% in 2003 to 3% in 2006 (Curry et al., 2007).

The information generated from this survey combined with the examples above is important for CCS developers to understand. The examples demonstrate the ability the public has to make or break a project's implementation and the survey gives insight into how the public views CCS as well as why pilot projects have failed in certain locations. While it seems that much of America believes that water merely comes from turning on the faucet and electricity from wall sockets, the opinions generated by this uniformed portion of the public still has the ability to stall or completely prevent a large scale project, like CCS, from coming to fruition. With greater media coverage of environmental issues, especially climate change, the government and CCS supporters have the opportunity to introduce a relatively ignorant public to the emission reduction technology.

Despite the increased exposure CCS and other environmental issues have had within recent years, public opinion studies have continued to report that most individuals remain uninformed about CCS (Malone et al., 2009). The public thus ranks CCS technology near the bottom of potential solutions for global climate change (Bachu, 2007). Before CCS technology becomes a climate mitigation strategy, the public will need two basic questions answered:

1. Will the CO_2 leak from its storage site?
2. What will happen if it does? (Bachu, 2007)

Several cases suggest that improved public knowledge of CCS increases its public acceptability, particularly when presenting the technology as a portion of a larger plan for climate change mitigation. However, as more costs are transferred to the public, the overall approval rate begins to decrease again. The public perceives risk much differently than the firms and engineers planning and implementing CCS technology. The public is concerned with accountability, while CCS developers are concerned with probability and other qualitative aspects of risk (Bachu, 2007).

Public Perception of Risks

The risk that the public associates with hazardous materials has the potential to increase opposition for the construction of new coal plants using CCS. Examples of these materials are amines and solvents used to separate CO_2 from the emissions stream and prepare it for transport and storage. Transporting large quantities of these chemicals over considerable distances may also be perceived as an additional risk. The public has expressed concern about potential accidents occurring during transit in addition to the national security risk that their movement poses (Parfomak, 2008). The catastrophic results of an accident involving hazardous material transportation could severely affect the communities surrounding the accident scene. Again, although these risks are minimal, the public is concerned about accountability.

Leakage of carbon dioxide is the main risk the public associates with CCS technology (Bachu, 2007). This concern is accompanied by other perceived risks and costs, such as the possibility of CCS inducing earthquakes, requiring the building of extensive infrastructure, as well as the high costs of implementation and operation (Parfomak, 2008).

The public may view CCS not only as a hazardous risk, but risky in terms of achieving climate change mitigation goals. Nearly 40% of those interviewed in a 2007 study felt that CCS would merely be a “quick fix that would not solve the greenhouse gas problem” (Parfomak, 2008). This may somewhat explain the reasoning behind a 2004 Carnegie Mellon University study that found that Americans are much less willing to pay for new CCS than any other large-scale emissions reduction technology, including the construction of nuclear plants. The public believes that opting to use CCS to control carbon emissions has the potential to hinder the development of longer-term solutions (Parfomak, 2008).

NIMBY Effect

Accountability issues are another concern of how the public views CCS. Stakeholders want to know who assumes responsibility for ensuring long-term security and who is accountable should a problem occur at each storage site (Bielicki and Stephens, 2008). These issues have yet to be resolved for current and proposed CCS sites, though they pose chief concerns for those living near pilot storage projects. Many Americans seem to support CCS until it is perceived to encroach upon their neighborhoods. This "not in my backyard" (NIMBY) mentality is common with the implementation of new technologies whose accompanying economic and social costs are somewhat unknown. Yet CCS facilities would not necessarily bring costs to locals and they could create jobs and advance economic development in the surrounding communities. Similarly, residents living near potential site locations usually accept or reject a prospective CCS facility based upon the perceived costs and benefits (Bachu, 2007).

CCS is not the only technology that uses hazardous materials, yet many people do not think about this when first learning about a new technology. Water treatment plants use ammonia and chlorine to treat wastewater, and refrigeration and poultry production facilities use ammonia and other hazardous materials in their day-to-day operations. Primarily due to public opposition, it is increasingly difficult to find locations willing to accept the development and implementation of any form of hazardous waste facility (Hunter and Leyden, 1995).

Proponents and Opponents of CCS

In addition to the company building the new facility, other interested parties also influence public attitude: environmentalists, civic groups, and NGOs. Their positions range from complete opposition to strong support. One opposing group is Greenpeace, which published a report in 2008 entitled, "False Hope: Why Carbon Capture and Storage Won't Save the Climate" (Greenpeace, 2008). On the other end of the spectrum, the Climate Legislative Director for the Natural Resources Defense Council (NRDC) stated that, "without widespread deployment of such technology, the task of fighting global warming will be more difficult" (NRDC, 2008). The messages from these larger groups tend to be distributed through press releases, reports, and studies that cover CCS broadly and that do not target a specific project, or geographic area.

On the other hand, smaller groups at the local level help influence public opinion in regions where there are proposed CCS projects. In Indiana, the Edwardsport Duke Energy IGCC plant and planned pilot CCS projects have received opposition from various groups. The Citizens Action Coalition is skeptical of Duke attempting to run a pilot program and opposes using ratepayers for financial support (Olson, 2009). Another active group called CLEAN edited a video approving of the Edwardsport plant and dubbed it over with their contrary message in an effort to undermine Duke's public outreach (CLEAN, 2010).

Recommendations for Engaging the Public

How the public is involved in a CCS project will depend on the context. However, there are general guidelines that the government and industries can follow in order to minimize public opposition. These guidelines can differ depending on whether the engagement is with a localized population (community, city, or county) or with a broad portion of the public (state, region, or nation). The following three recommendations summarize the important points.

First, a social site characterization should be carried out early on in the planning process to engage the local population regarding any new CCS facilities. This includes identifying key stakeholders as well as factors that drive public perceptions and attitudes in that particular geographic area. For example, a community with multiple hazardous waste sites nearby may oppose another potential hazard on environmental justice grounds. It is possible that a planned CCS facility may be moved after a social site characterization has been completed due to expected adverse public acceptance.

Second, the FutureGen project example demonstrates the importance of using multimedia to inform and engage the public in the CCS development process. In the situation where an existing facility is retrofitted for CCS, the local residents may already be accustomed to working with the incumbent company. In this case, if the company already has a poor reputation with locals it may not matter what kind of public engagement is used. On the other hand, if the local community only cares about local jobs to spur economic development, then the company's reputation and public engagement plans may not be as important. In both cases, the company proposing the CCS facility should establish reasonable public engagement goals, such as responding to all public comments, or holding public meetings to establish and resolve the most contentious issues. Throughout all the stages of the project, the company should strive to maintain an open, transparent decision process through which concerned stakeholders may receive answers (Malone, 2009).

Third, the broader population is going to be more concerned with rate increases on utility bills and whether CCS is the best approach toward managing carbon emissions. These individuals will need information on the benefits of CCS relative to other low-carbon options, as well as some realistic cost estimates. The residents near a proposed facility will be interested in how many new jobs will be available, what the potential safety and health risks will be, and who will be held accountable should something go awry.

Thus, in general, in addition to these recommendations, a company proposing a CCS facility should:

1. Maintain transparency throughout all phases of the project;
2. Reach out to the local community as well as the broader public; and
3. Be aware that certain localities may oppose a project no matter the quality of the public outreach.

Chapter VII: Policy Instruments with Cost Comparisons

Domestic Policy Instruments

The costs associated with potential CCS applications depend on future federal investment, technology advancements, property rights legislation, and public acceptance. A variety of policy instruments are necessary to assist CCS deployment, research and development, and cost minimization. These instruments could include financial incentives, technology specifications, performance standards, emission quotas, and market-based emission control schemes. Regulation may target CCS technology itself, emitting facilities, or CO_2 emissions. These instruments differentially affect industry in terms of the flexibility of compliance pathways, incentives to invest in CO_2 abatement innovation, and incurred abatement costs. Federal financial incentives shift the financial burden from producers to the public.

Marketable allowances (emissions-trading systems) and emissions taxes (fees or charges) provide distinct economic incentives to reduce emissions. An emissions trading system utilizes a quantity instrument that limits allowable emissions by restricting CO_2 permits and allows for trading within industry. This feature enables polluting firms to purchase or sell permits based upon their individual costs to reduce emissions. A CO_2 fee or tax, achieves abatement cost minimization where firms with low abatement costs will invest in pollution reduction techniques and firms with more expensive costs will continue to emit and pay the tax (Portney, 2003). Further information on regional initiatives is in Appendix D.

Command-and-Control

Historically, technology standards effectively "froze" pollution control innovation as it removed the incentive to invest in less expensive technology since a particular type already received regulatory approval (Portney, 2003). CCS is the leading CO_2 abatement technology from fossil fuel power generators whose technical status will likely determine any technology-based standards of CO_2 control. Under the Clean Air Act (CAA), new point sources and existing facilities that undergo significant modifications are required to meet New Source Performance Standards (NSPS). The EPA establishes guidelines for NSPS that specify standards for pollution control systems.

The Energy Independence and Security Act of 2007 (EISA) mandates that the Environmental Protection Agency assess the impacts of carbon storage on human and environmental health. The EISA further indicates that carbon injection is subject to the Federal requirements under the Underground Injection Control section of the Safe Drinking Water Act of 1974 (Congressional Research Service, 2009). The EPA has since proposed to add a new injection classification specifically for geologic storage of CO_2 (EPA, 2009).

Several states are incorporating emissions performance standards (EPS) into their energy and climate change policies. Within the legislation, point-source emitters are required to reduce their emissions by a certain percentage based on varying criteria. Additionally, a number of states have enacted or are developing clean energy and climate change policies, greenhouse gas emissions targets, and comprehensive climate action plans. A Pew Report lists Washington, Oregon, California, Montana, and Illinois as having the most advanced emission performance standard policies that cite CCS as a mitigation option (Pew Center on

Global Climate Change, 2010). For further information regarding state policies see Appendix E.

Financial Incentives

Subsidies may take a variety of forms, including tax incentives and grants. Government financing of CCS may also come in the form of public-private partnerships, pilot projects owned or directed by the government, and funding of CCS research at public institutions. By supporting demonstration projects, government initiatives may counter the high performance uncertainty that deters private investment. Advancing the technology from a conceptual phase to a production phase could enable the "learning-by-doing" environment required to expand production rates and lower costs (Kapp, 2004). The effect would accelerate the competitive delivery of CCS to the marketplace. Furthermore, a buy-down policy for CCS deployment can take the form of subsidies or public purchases. The Pew Center on Global Climate Change maintains that 10-30 CCS demonstrations at commercial coal plants, at an $8-$30 billion program cost, are necessary to advance CCS (Kuuskraa, 2007). Therefore, government supported pilot and demonstration projects may play an instrumental role in furthering CCS technology development, cost reductions, and deployment.

Federal Actions under the American Recovery and Reinvestment Act (ARRA) include a $3.4 billion appropriation for the Department of Energy's Fossil Energy Research and Development Program (Congressional Research Service, 2009). The program's mission is to further the development of technologies that will allow for continued use of fossil fuels in a more environmentally conscious manner. This appropriation specifies various allocations of funds including a $1.52 billion solicitation for industrial CCS projects (U.S. DOE/NETL, 2010b).

The DOE has awarded public-private funding to twelve diverse companies across the U.S. in October 2009, which included cement plants, paper mills, and oil refineries (U.S. DOE/NETL, 2010b). The projects that demonstrate the most success of the stated goals will be awarded funding for a second phase (U.S. DOE, 2009).

Regional Financial Incentives and Public Expenditures

The Regional Carbon Sequestration Partnerships, formed as a part of the DOE's Carbon Sequestration Program under the Clean Coal Power Initiative, are public-private partnerships that address gaps in regulation, technology, and infrastructure based on seven geographic regions throughout the United States and Canada. Their efforts occur in three successive phases lasting from 2003 - 2017: Characterization Phase, Validation Phase, and Deployment Phase. The program is currently in the Deployment Phase, which consists of large-scale storage demonstrations. In December of 2009, three projects received $3 billion in DOE funding. The AARA stipulated an additional $800 million for this effort (U.S. DOE/NETL, 2010a). These projects were selected on the basis of three platforms; (1) the technologies target a 90% capture efficiency, (2) the technologies do not increase the cost of electricity by more than 10 %, and (3) the projects capture at least 300,000 tons of CO_2 per year (U.S. DOE, 2009).

State funding from ARRA has been committed to various projects that span the continental U.S. There are dozens of proposed bills that offer financial incentives for CCS from state generated funds. Colorado, Minnesota, and New Mexico have already established financial incentives specific to CCS. For more information regarding regional incentives, see Appendix E.

Cost Comparisons

In this comparative cost analysis, several alternative low-carbon electric generation technologies were considered along with the fossil technologies examined earlier in the report. The alternative technologies selected were on-shore and off-shore wind, nuclear, solar thermal, and photovoltaic. Hydroelectric, biomass, and geothermal were excluded due to a lack of commercial-scale deployment capacity or limited potential for future expansion.

The undeveloped capacity for domestic hydropower has been estimated at 30,000 MW or approximately 40 percent of existing capacity from conventional hydropower (DOI, 2005). Large-scale geothermal technologies have not been demonstrated and the source is unlikely to exceed hydropower in installed capacity without spectacular improvements (Nature, 2008). The capacity outlook for dedicated biomass facilities appears to be minor and that the more likely role of biomass is as a co-fired fuel in coal-fired plants. A modified coal-fired unit may generate upwards of 15 percent of its total power output with biomass fuel (DOE, 2010). Therefore, we conclude that hydropower, geothermal, and biomass cannot compete with fossil fuel applications of CCS at a large scale.

Power Dispatch Characteristics

Dispatch characteristics are an important cost and reliability aspect of electric power systems. Generation technologies vary by relative capital and operating cost as well as the ability to change production levels over time. While demand fluctuates by hour, day, and season, a minimal amount of load is constant, referred to as the baseload. In an attempt to generate power at the lowest overall cost per kilowatt-hour, baseload is typically from coal and nuclear power that have relatively high capital and low operating costs. During periods of greatest demand, or peak load, the lowest-cost technologies are those with relatively low capital costs and higher operational costs (Bosselman, 2006). NGCC can play a unique role as a load-following technology. The generation technologies that are CCS applicable (namely coal-fired and NGCC plants) typically operate as baseload power with natural gas serving as the peaking power source (Lazard, 2008). Table 4 illustrates dispatch characteristics of the technologies included in this analysis.

Table 4: Site and Dispatch Characteristics of Various Power Generation Technologies

	Geography	Baseload	Peaking	Load-following	Intermittent
IGCC	Co-located or rural	●			
NGCC	Universal	●		●	
Conventional Coal	Co-located or rural	●			
Nuclear	Co-located or rural	●			
Wind	Varies				●
Photovoltaics	Universal		●		●
Solar Thermal	Southwest		●	●	●

Lazard, 2008

Wind and solar technologies have intermittent power dispatch characteristics due to meteorological variability (Lazard, 2008). In contrast to the economic value offered by sources filling other dispatch niches, intermittent power sources are an economic burden that strain reserve capacity. Spinning and non-spinning reserves, which either operate at lower capacity and ramp production quickly or start-up within a half hour, are capable of responding to such supply disruptions (AWEA, 2009). The primary technologies to serve in this role are hydropower and natural gas plants (AWEA, 2009). Wind production may be supported by load-following, existing voltage regulation, and spinning reserves (Kelly and Weinberg, 1993). Current grid systems appear suited to handle wind additions on the order of 10-20 % on a capacity basis (Parsons et al., 2006). Therefore, to achieve significant market penetration, wind installations must be supplemented with accommodating reserve capacity. Considering the limitations on hydropower expansion, we used NGCC as a backup power source to wind in this analysis.

Geographic Constraints and Site Selection Characteristics

Geographic constraints can significantly impact the cost of generation and electricity transmission. Physical requirements for power plant sites include: transport systems for fuel and large capital components, connections to the transmission grid, and proximity to water for cooling or other purposes (Tester et al., 2005).

The cost of delivering electricity incorporates power generation, transmission, and distribution. In areas where transmission lines are sparse or inadequate, utilization of wind generation may increase costs significantly. A limiting factor for wind is that the windiest locations are seldom very populous, thus developing many sites would require infrastructure construction (Nature, 2008). In particular, a great deal of the high-quality wind resource in the United States is found in the sparsely populated Great Plains (Elliott et al., 1991). A similar problem would be expected for solar thermal, which is regionally constrained to the Southwest (Lazard, 2008).

Energy is lost over prolonged transmission distances, thus driving up the cost of delivered electricity. Therefore, generation sources distant from load centers produce electricity that is more expensive upon delivery than from local sources. A key advantage for fossil fuel facilities is the ability to transport their fuel source to the facility, unlike wind, solar, geothermal, and hydroelectric that must be sited at the location of the resource. The costs of transmitting electricity may be prohibitive enough to restrict solar and wind to certain regional markets. In contrast, fossil fuel generators can either be universally sited or at worst face only local constraints (Lazard, 2008).

Although not included in our cost analysis model, accounting for costs associated with transmission capital and energy losses strongly favors fossil fuels, and therefore CCS, over geographically constrained generation technologies. The relative magnitude of these effects may greatly determine regional developments of CCS or wind technologies under a low-carbon scenario.

Electricity Cost Comparisons

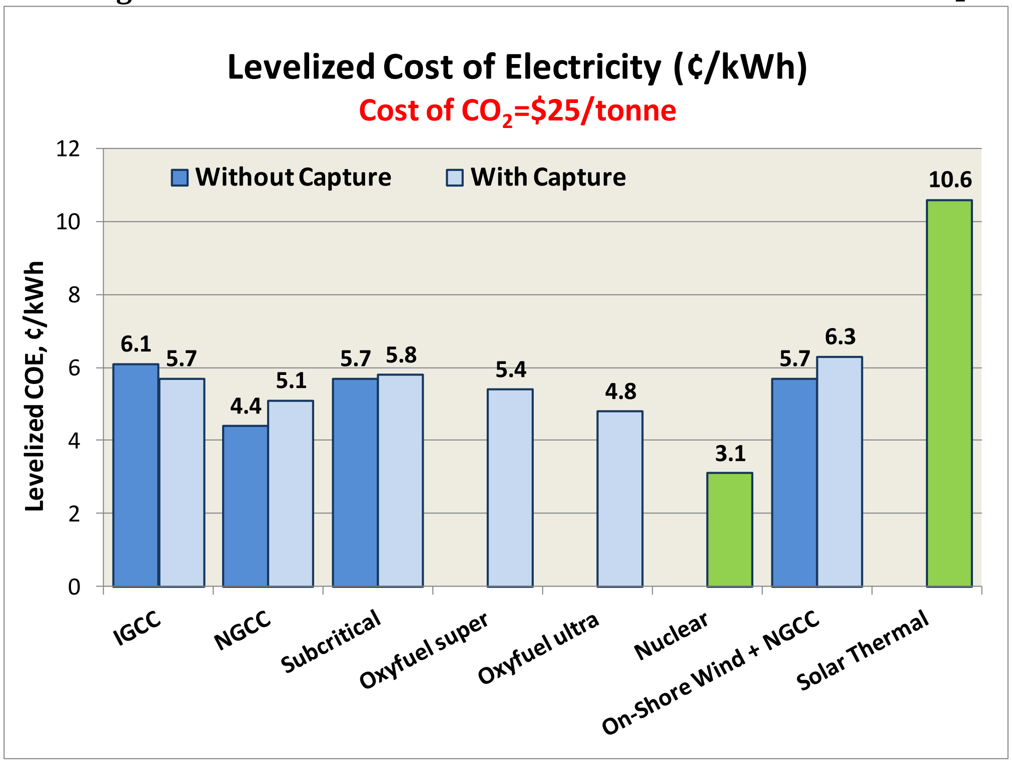
In a competitive electric power market, the costs of power generation drive decisions on generation technology choice and levels of private investment and deployment. The cost-competitiveness of CCS applications is not only a function of the cost of generation facilities with CCS but of competing power generation technologies. The costs associated with potential CCS applications as well as other generation technologies are determined by market dynamics and the effects of public policies. A critical measure of the potential role CCS will play in the electric power generation sector in the United States is the cost of electricity from facilities with CCS, relative to competing low-carbon technologies, under differing sets of policy assumptions.

The following comparative cost analysis examines the effect of CCS technology on the levelized cost of electricity for both current fossil fuel technologies and for selected alternative low carbon power generation systems. The levelized cost of electricity is the present value of the cost of operating a power generation system over its lifetime and includes investment, capital, operating and maintenance, and fuel costs. The cost analysis assessed these effects for not only a base case scenario for power generation but also situations including subsidies and various prices on CO_2 emissions.

This analysis also examined the effect on the levelized cost of electricity (COE) if an explicit or implicit price were placed on carbon through either a carbon tax or a marketable allowances scheme, respectively. Figures 14 and 15 illustrate changes to the levelized COE when the price of CO_2 increases from $0 (as in the basecase presented earlier in Figure 6) to $25 to $50 per tonne.

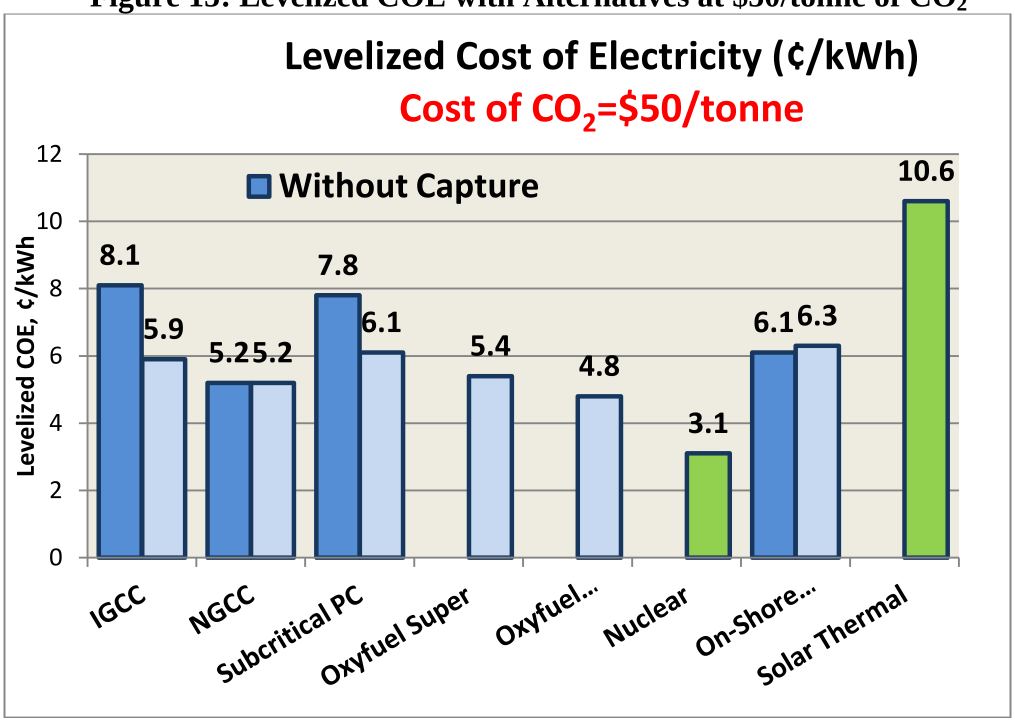
The fossil fuel technologies experience an increase in levelized costs of 40 to 50% with an increase in CO_2 price from $0 to $25. The same technologies with CCS have an increase of only 5 to 7% in levelized costs coinciding with the increase in the price of CO_2. For all capture-applicable technologies, without CCS is still the least expensive option at $25/tonne of CO_2, except for IGCC.

Figure 14: Levelized COE with Alternatives at \$25/tonne of CO_2



Sources: EIA, 2007; U.S. DOE/NETL, 2007c; NETL 2007; DOE - module, 2010; Logan and Kaplan, 2008; EIA - module, 2010

Figure 15: Levelized COE with Alternatives at \$50/tonne of CO_2



Sources: EIA, 2007; U.S. DOE/NETL, 2007c; NETL 2007; DOE - module, 2010; Logan and Kaplan, 2008; EIA - module, 2010

At every price of CO_2, nuclear power is the least-cost generation technology. NGCC emerges as the second least-cost technology up until a carbon price of $36/tonne CO_2, at which point it thereafter exceeds the cost of oxyfuel ultra supercritical. Both oxyfuel supercritical and ultra supercritical are lower cost at every price of carbon than all other coal technologies with carbon capture.

Without a price on CO_2, the combination of wind and NGCC is more expensive than all technologies without capture except oxyfuel supercritical. It becomes less expensive than all coal without CCS technologies at mid-range CO_2 prices (around $15 to $30/tonne of CO_2). However, at this price the COE does surpass oxyfuel supercritical. Without a CO_2 price, the wind-NGCC combination is lower-cost than all coal with capture technologies except for oxyfuel ultra supercritical, and is comparable to NGCC with capture. At a price of $50/tonne CO_2, wind with NGCC exceeds the COE of IGCC with capture and equals subcritical with capture.

When the cost of CO_2 is $50/tonne or higher, the least-cost choice for all fossil-fuel generators is to use CCS technology. On-shore wind, when coupled with NGCC with carbon capture, show a very slight increase in COE as CO_2 prices increase, whereas wind with NGCC increased 14% at $25/tonne CO_2, 22% at $50/tonne CO_2, and 40 % at $100/tonne CO_2 relative to the COE at $0/tonne CO_2. Off-shore wind, photovoltaics, and solar thermal are not cost competitive under any scenario, and NGCC without capture is the lowest cost option for all fossil fuel technologies.

Breakeven CO_2 Price for Adding Carbon Capture

The breakeven CO_2 price for adding CCS is the point where, as the price of CO_2 increases, the incremental cost of adding carbon capture equals the cost of paying a carbon tax or purchasing a pollution permit. At CO_2 prices below this level, the least-cost option is to "pay to pollute." At CO_2 prices above this level, the least-cost option is to invest in carbon capture and storagae technology. Table 5 shows the lowest price for adding CCS is for IGCC technology at $21.96/tonne CO_2.

Table 5: Breakeven CO_2 Price

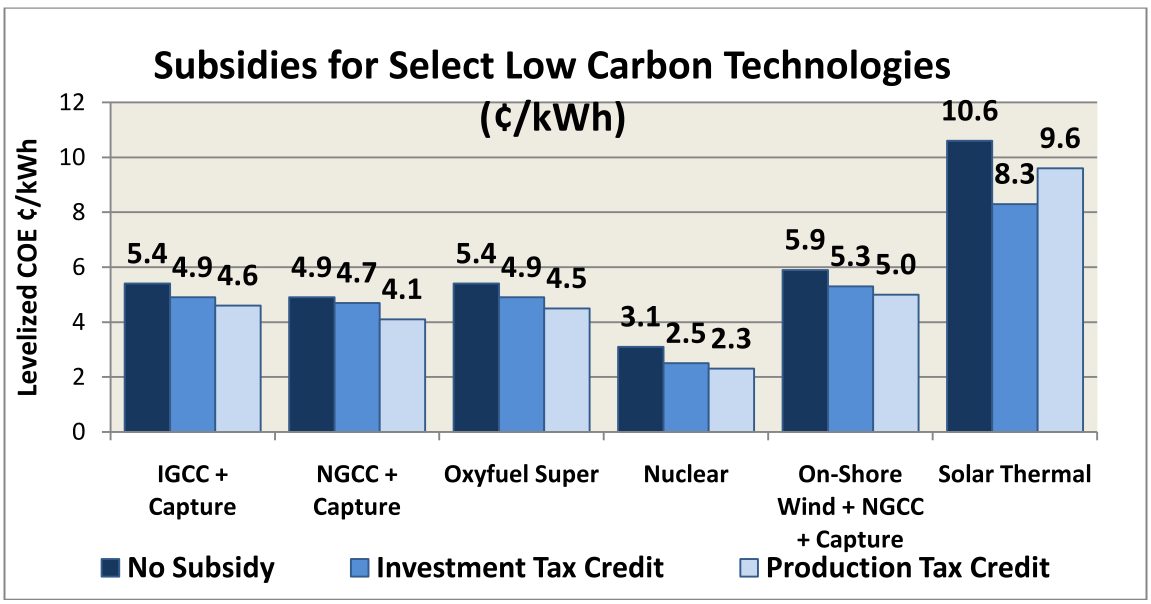
Type of Technology	$/tonne of CO2
IGCC	21.96
NGCC	43.82
Subcritical PC	27.35
Supercritical PC	31.82

Cost Comparison of Investment or Production Tax Credits

This analysis focused on production tax credit (PTC) and an investment tax credit (ITC) that assists in offsetting operational and capital costs, respectively. Under Section 48 of the Energy Policy Act of 2005, certain gasification projects such as IGCC facilities became eligible for a 20% credit (maximum of $800 million), while other advanced coal technologies qualified for a 15% credit (Metcalf, 2007). Current law increased the PTC offered under the 2005 legislation to $0.021/kWh for select renewable source technologies (DSIRE, 2009). Based on these figures, our analysis assumes a 20% credit for a hypothetical ITC and $0.02/kWh for a hypothetical PTC for the first 10 years of operation. Qualifying technologies are renewable sources, fossil fuel sources with carbon capture, and nuclear.

As shown in Figure 16, the PTC lowers the cost of electricity by almost the same amount for all fossil fuels with carbon capture. While the ITC has roughly the same impact on IGCC with capture and oxyfuel supercritical; it is far less effective for NGCC with capture. The impacts of both the ITC and PTC on nuclear, IGCC with capture, and oxy-fuel supercritical are comparable to those on the pairing of wind and NGCC with capture. In sharp contrast to NGCC, wind technology is capital-intensive with minor operational expenses. The PTC lowered the cost of electricity more than the ITC for every technology except solar thermal, a reflection of the relative capital and operational costs between technologies.

Figure 16: Cost Comparisons without Subsidy, with ITC or with PTC



*Investment Tax Credit = 25% of Capital
*Production Tax Credit=$.02/kWh for 10 years
Sources: EIA, 2007; U.S. DOE/NETL, 2007c; NETL 2007; DOE - module, 2010; Logan and Kaplan, 2008; EIA module, 2010

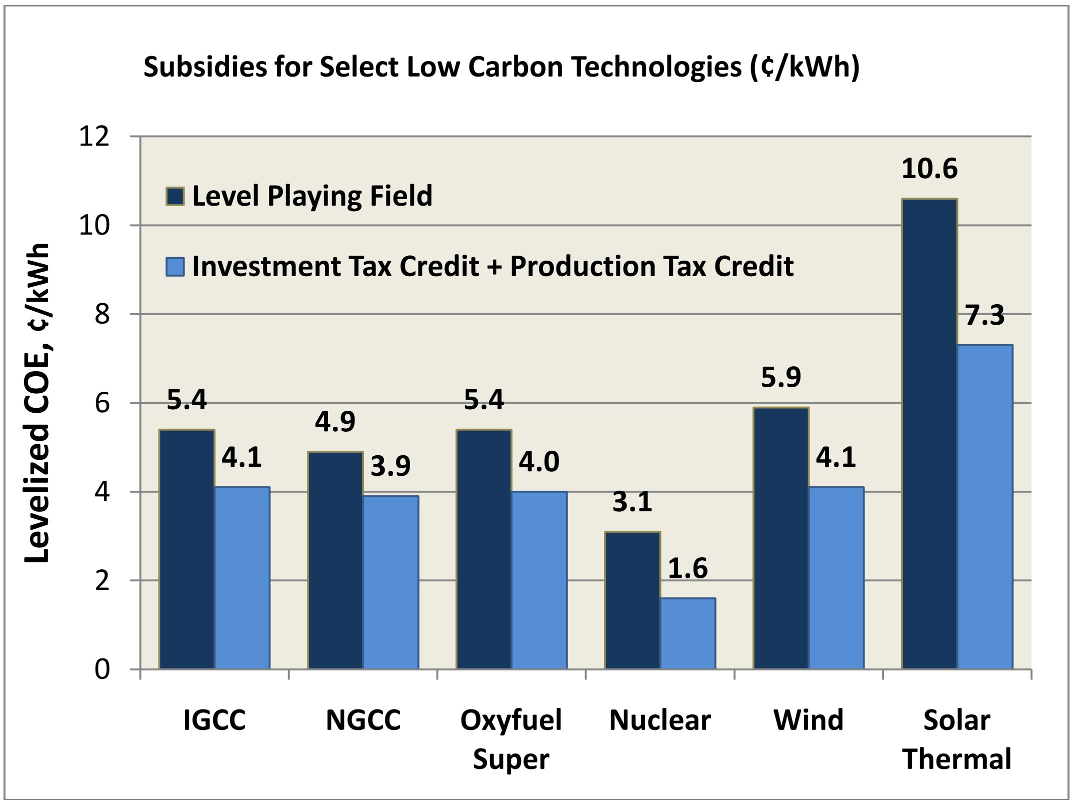
The impacts of ITC or PTC were not significant enough to change baseline relationships among technologies. Neither subsidy resulted in an increased competitiveness of solar thermal. Nuclear without a subsidy remained at least a $0.01/kWh lower cost than other technologies including a subsidy.

As seen in Figure 17, the combination of ITC and PTC had the largest effect on the cost of electricity of wind and NGCC with capture of all fossil fuel-based technologies at a $0.018/kWh decrease. IGCC with capture and oxy-fuel supercritical were comparable while

NGCC had the lowest cost reduction of $0.01/kWh. The subsidy combination did not make solar thermal competitive, even with other technologies excluding a subsidy. Nuclear without a subsidy remained at least a $0.008/kWh lower cost option than any other technology with the subsidy combination.

The subsidy combination did alter competitive relationships for certain technologies. At a level playing field, the coal-based technologies with capture were notably more expensive than NGCC with capture and notably less expensive than wind and NGCC with capture. With the subsidy combination, all four of these technologies are relatively comparable.

Figure 17: Cost Comparison including both ITC and PTC



*Investment Tax Credit = 25% of Capita
*Production Tax Credit=$.02/kWh for 10 years
Sources: EIA, 2007; U.S. DOE/NETL, 2007c; NETL 2007; DOE - module, 2010; Logan and Kaplan, 2008; EIA - module, 2010

Throughout the analysis, nuclear power generation remained the most cost-competitive option at $0.03/kWh. However, expeditiously scaling-up nuclear power generation faces considerable hurdles. Removing nuclear, CCS coal applications are cost-effective low-carbon technologies with favorable siting and dispatch characteristics, suggesting a crucial role for CCS during periods or in locations of nuclear deficit.

Additionally, oxyfuel technologies remained relatively cost competitive throughout the analysis. Because they are not as developed as some of the other fossil fuel technologies, federal investment in research and development into oxyfuel technology specifically is necessary for more widespread deployment in the long run. Similar support for IGCC is necessary as the US lacks experience in IGCC at a reasonable commercial scale of 450 MW at minimum.

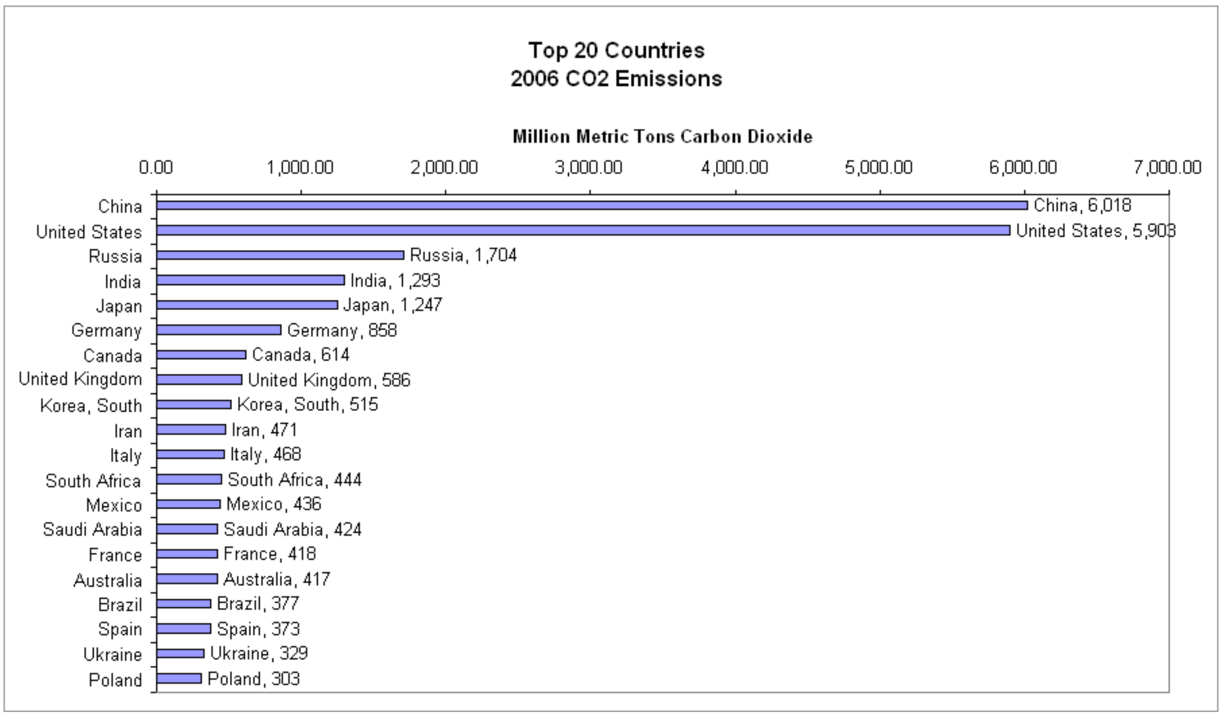
Chapter VIII: International Policies, Regulations, and Public Acceptance

Global CO_2 Emission Projections

Of the 192 countries officially recognized around the world, each contributes different amounts of carbon dioxide to the atmosphere. This unequal contribution of carbon dioxide emissions, from developed and developing countries alike, is at the core of challenges to finding effective and equitable carbon managements solutions.

The data compiled by the IEA estimates carbon dioxide emissions from all sources of fossil fuel burning and consumption (IEA, 2009a). Figure 18 depicts total 2006 emissions for the 20 top emitting countries.

Figure 18: Top 20 Countries Carbon Dioxide Emissions in 2006



Union of Concerned Scientists, 2009b

In general, developed countries have high carbon dioxide emission per capita, while some developing countries lead in the growth rate of carbon dioxide emissions (Union of Concerned Scientists, 2009b). For example, China is now the world's largest emitter while Russia, India, South Korea, and Iran are rapidly becoming large carbon dioxide emitters. Therefore, among the worlds' countries, these high emitting countries should especially focus on carbon management strategies to curb global CO_2 emissions.

Furthermore, global carbon dioxide emissions are rising faster than before. From 2000 to 2005, emissions grew four times faster than in the preceding 10 years. Global growth rates were 0.8% from 1990 to 1999, growing to 3.2% between 2000 and 2005 as shown in Table 6 (Brahic, 2006).

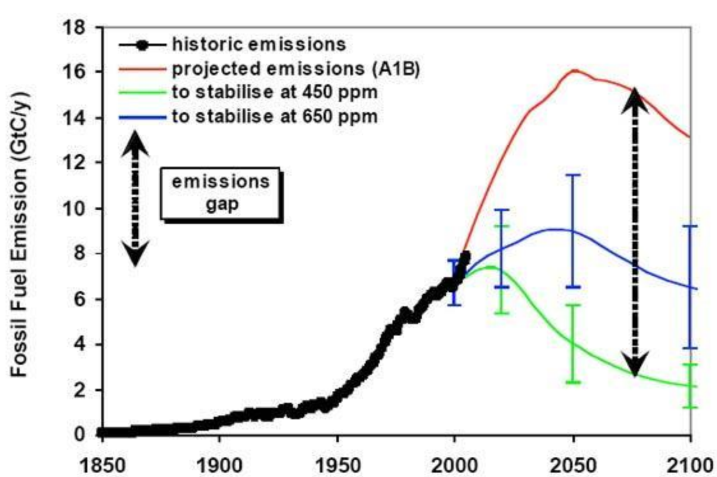
Table 6: World Energy Consumption and Carbon Dioxide Emissions, 1990-2025

Region	Energy consumption (quadrillion BTU)				Carbon dioxide emissions (million metric tons)			
	1990	2001	2010	2025	1990	2001	2010	2025
Industrialized nations	182.8	211.5	236.3	281.4	10,462	11,634	12,938	15,643
Eastern Europe/Former Soviet Union	76.3	53.3	59.0	75.6	4,902	3,148	3,397	4,313
Developing nations								
Asia	52.5	85.0	110.6	173.4	3,994	6,012	7,647	11,801
Middle East	13.1	20.8	25.0	34.1	846	1,299	1,566	2,110
Africa	9.3	12.4	14.6	21.5	656	843	971	1,413
Central and South America	14.4	20.9	25.4	36.9	703	964	1,194	1,845
Total developing	89.3	139.2	175.5	265.9	6,200	9,118	11,379	17,168
Total world	348.4	403.9	470.8	622.9	21,563	23,899	27,715	37,124

EIA, 2003 and 2004

With this trend, it will be extremely hard to reduce carbon dioxide emissions enough to stabilize the atmospheric carbon dioxide concentration at 450 ppm (Brahic, 2006), which could limit global warming to 2°C as agreed upon in the Copenhagen Accord of 2009. It is important for developed and developing countries to work towards more ambitious climate targets via international actions, including the acceleration of technological co-operation initiatives to help developing countries to decrease carbon dioxide emissions (Brahic, 2006). Figure 19 depicts the potential future emissions trends.

Figure 19: Historic and Projected Carbon Dioxide Emissions



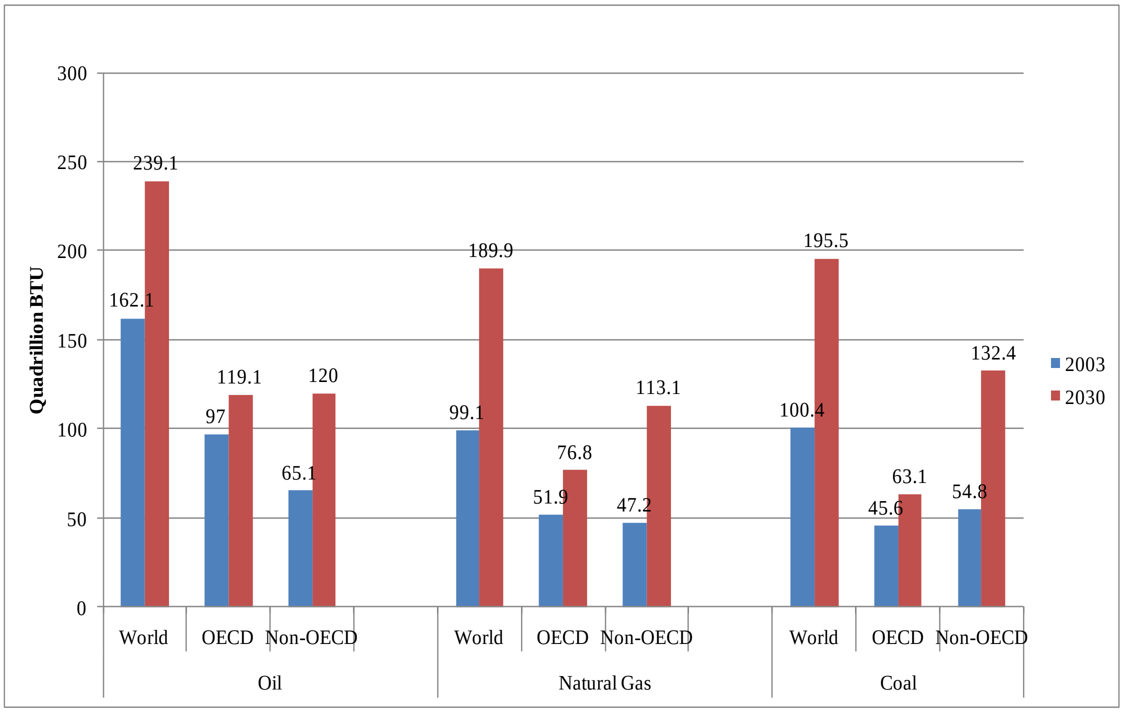
Brahic, 2006

Carbon management strategies are imperative to affecting a change in climate emission patterns, and without question, some actions must be taken towards comprehensive carbon management on an international scale.

International Energy Use

World fossil fuel energy use as a proportion of total energy use is projected to increase by 0.71% from 85.93% to 86.54% (including the use of nuclear and renewable energies). The greatest increase by energy source is seen with coal, as depicted in Figure 20.

Figure 20: International Fossil Fuel Use



Adapted from information obtained from EIA, 2009

OECD fossil fuel energy use will increase by 0.99% of total energy use from 83.05% to 83.87%. Although non-OECD fossil fuel energy use as a proportion of total energy use will decrease by 1.17% from 89.6% to 88.54%, the rate of increase is still significant.

International Dependence on Coal

The challenge in selecting a carbon management strategy is figuring out which will be the most effective. Furthermore, these strategies are often contingent upon the type of fuel source. Coal is the most dominant energy source in electricity generation in both OECD members and non-OECD members. Non-OECD members (developing countries) use coal for 46 % of total electricity generation while OECD countries (developed countries) use coal for 37% total electricity generation (Adamec et al., 2009).
First, recoverable coal reserves are widely distributed throughout the world, though non-OECD countries have greater reserves than OECD countries: 58% to 42% (EIA, 2010c).

Emerging economies such as China, India, South Africa, and Russia have about 44 % global reserve of coal. Table 7 depicts coal reserves across countries these countries and the world.

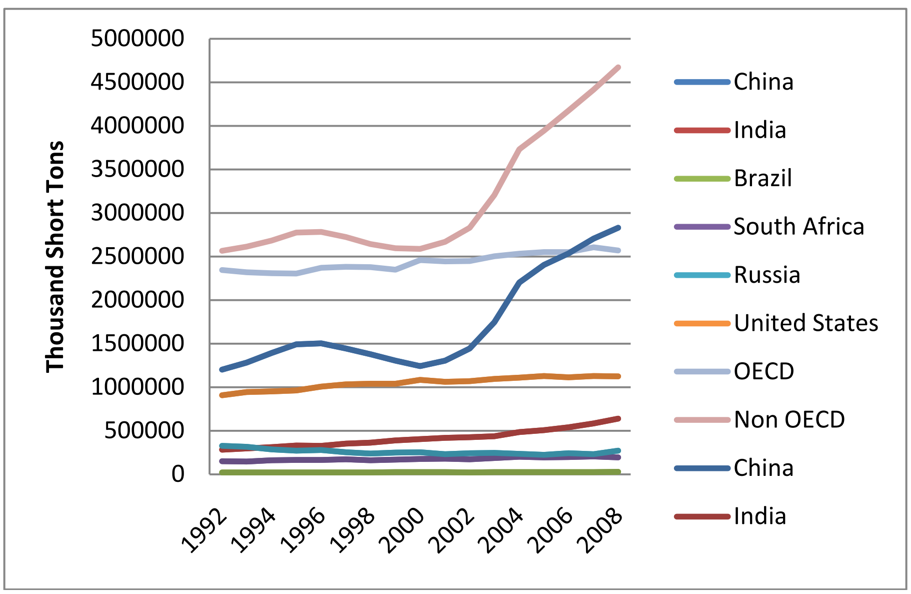
Table 7: Global Coal Reserves in 2005

	Million Short Tons	Percentage
China	126214.65	13.57%
India	62278.39	6.69%
Brazil	7791.14	0.84%
South Africa	52910.95	5.69%
Russia	173073.9066	18.60%
United States	263781.00	28.35%
Australia	84437.05014	9.08%
E.U.-27	32595.35	3.50%
OECD	389652.83	41.88%
Non OECD	540769.70	58.12%
World	930422.53	100.00%

EIA, 2010c

Second, coal consumption in non-OECD countries has increased markedly since 2002 while OECD countries' consumption has only moderately increased. Notably, China's consumption trend follows a similar path as non-OECD countries as shown in Figure 21.

Figure 21: Total Coal Consumption



EIA, 2010c

Considering the availability of recoverable coal reserves and the increasing consumption trends, it likely follows that most of the near future's electricity generation will come from coal. This projection guarantees future CO_2 emission increases for the world unless large carbon mitigation strategies are implemented.

International CO_2 Capture and Storage Potential

If CCS were implemented worldwide, how much CO_2 could be captured? The potential of CO_2 capture can be estimated in various ways. One method is based off scenarios for future energy demand and CO_2 emissions. The results in Table 8 show how much would be captured by this method. It shows that the global CCS potential could capture up to 236 billion tons of CO_2 emissions by 2050. Of this 236 billion, 101 billion (or 43%) would be captured by OECD countries and 135 billion (or 57%) would need to be captured by non-OECD countries.

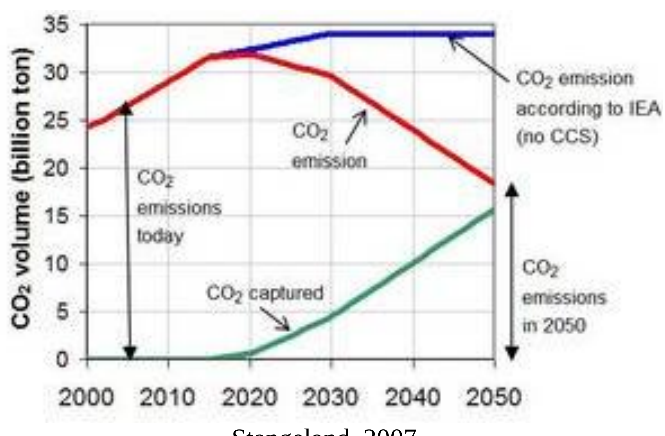
Table 8: Potential for CO_2 Emissions Reduction

Area	Annually CO_2 capture in 2050 [billion ton]	Potential for accumulated CO_2 capture by 2050 [billion ton]	Reduction in CO_2 emissions*
EU	1.7	25	54 %
OECD countries	7.0	101	53 %
non-OECD countries	8.7	135	16 %
World	15.7	236	33 %

Note: Reduction in CO_2 emissions in 2050 compared to CO_2 emissions in 2007 (Stangeland, 2007).

If the world could reach this potential, there would be a 33% reduction in global CO_2 emissions in 2050 compared to emissions in 2007, as shown in Figure 22 (Stangeland, 2007).

Figure 22: The Global CCS Potential



Stangeland, 2007

Table 9 outlines the technical potential for CO_2 capture in different industries in non-Annex I countries (which are developed countries and countries in transition). The technical potential for the volume of CO_2 capture in these countries is 9.3 billion tons of CO_2 around 2020; the short-term technical potential for industries that generate capture-ready CO_2 is 584 million tons CO_2 per year by 2012. It assumes all CO_2 capture technologies will be mature by 2020 noting that the actual take-up of CCS projects will be lower than the technical potential (Philibert, Ellis, and Podkanski, 2007).

Table 9: Short and Long-term Technical Potential for CO_2 Capture

Non-Annex I countries, selected industries (million tons CO2/year)	**To 2012**	**2020**
Hydrogen production	7.1	7.1
Refineries	322.3	322.3
Ammonia production	77.7	77.7
New coal-fired electricity	--	2193
Retrofit of fossil-fired power stations	--	5077
Retrofit of cement factories	--	1270
Natural gas processing	167	334
Enhanced oil recovery	10	20
Total	**584.1**	**9301.1**

IEA, 2006 and Cui, 2006

If CCS were implemented worldwide, how much of the captured CO_2 could be stored? While maps exist with general overviews of potential saline formations, a major indicator of storage capacity are the current countries investigating CCS development. There are 62 active, planned, or commercial scale, integrated CCS projects. Of these, 11% of the projects are in Australia and New Zealand, 10% in Canada, 37% in Europe, and 24% in the United States. The distribution of the projects in Asia, including China and India, are comparatively low at just 5 (Global CCS Institute, 2009).

There are five operating, fully integrated, commercial-scale CCS projects such as the Sleipner and Snøhvit projects in Norway, the In Salah project in Algeria, the Ragely project in the United States, and the Weyburn-Middle project in Canada (IEA, 2009c). In 2009, about 6 metric tons (Mt) of CO_2 was stored from these projects (Gale, 2009). Total global CO_2 emission from consumption of energy in 2008 was 30.377 billion metric tons per year (Mtpa) according to the EIA and the five CCS projects can store merely 0.0197% of CO_2 emissions (EIA, 2009). Table 10 depicts the locations of these projects.

Table 10: Active or Planned Commercial-scale, Integrated CCS Projects

Region	Planning	Operating	Total
Africa	·	1	1
Australia and New Zealand	7		7
Canada	5	1	6
China	4	·	4
East Asia(ex. Japan)	1	·	1
Eastern Europe	4	·	4
Europe Area	21	2	23
Middle East	1	·	1
U.S.A.	12	3	15
Total			62

Table 11 shows the cumulative amount of CO_2 injected from the current and planned storage projects as of early 2009 including EOR. The collective storage rate will be about ten Mtpa and it will mitigate 0.0329% of 2008 total global emissions (Global CCS Institute, 2009).

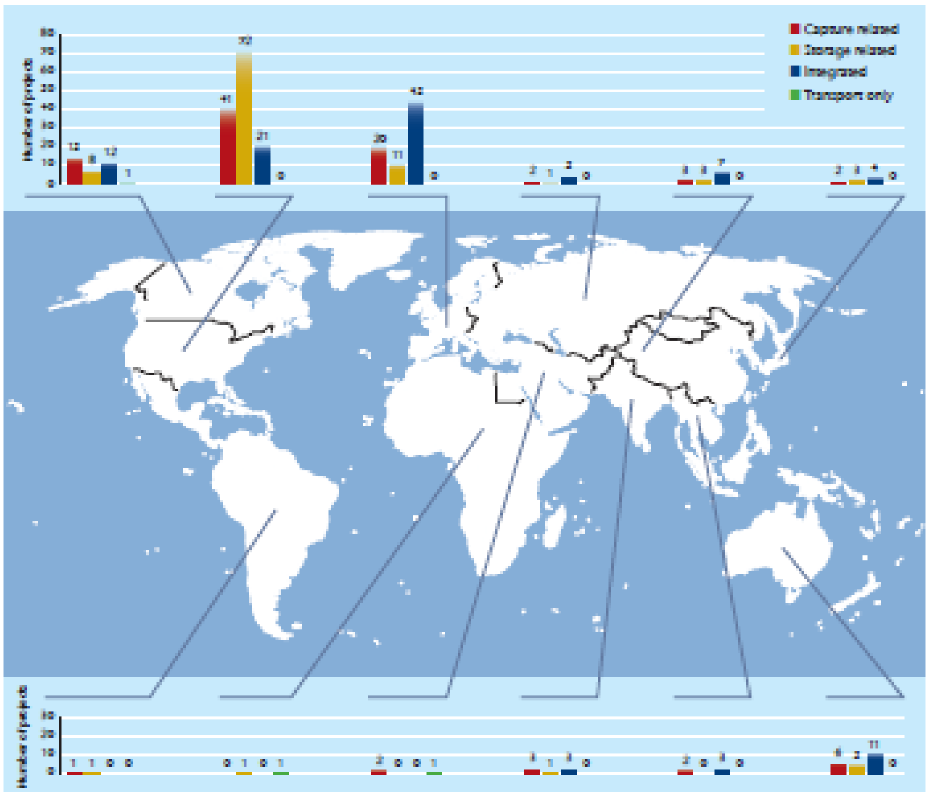
Table 11: Existing and Planned CO_2 Storage Projects of Early 2009

Project	**CO_2**	**Country**	**Start of Injection**	**Amount injected by**		
				2006	2010	2015
Rangely	GP	U.S.A.	1986	22Mt	25Mt	29Mt
Sleipne	GP	Norway	1996	9Mt	12Mt	17Mt
Weyburn	Coal	Canada	2000	5Mt	15Mt	26Mt
In Salah	GP	Algeria	2004	2Mt	7Mt	12Mt
Midale	Coal	Canada	2005	1Mt	3Mt	5Mt
Ketzin	NA	Germany	2007	·	50kt	50kt
Otway	Natural	Australia	2007	·	100kt	100kt
Snøhvit	GP	Norway	2008	·	2Mt	5Mt
Gorgon	GP	Australia	2010	·	0	12Mt
Total				**39Mt**	**64Mt**	**106Mt**

Global CCS Institute, 2009 (GP: gas process, NA: not applicable, the amount of CO_2 injected is cumulative)

Figure 23 depicts the geographical range of an additional 100 planned projects (Kerr and Beck, 2009).

Figure 23: Planned and Operational Large-scale (>1 Mt CO_2/year) CCS Projects



Kerr and Beck, 2009

While technological potential is high, the practicability of deploying CCS on an international scale is low. The following sections will discuss CCS international policies, regional agreements, legal regulations, intellectual property rights, and public acceptance that affect CCS possibilities internationally.

International CCS Policy

CCS is not currently considered a regulated carbon mitigation strategy under the international Kyoto Protocol. There are a number of interrelated factors that must be met before CCS can be included and seen as a viable mechanism including:

1. A new agreement to replace the Kyoto Protocol with stronger enforcement mechanisms;
2. Inclusion of CCS options within the existing CDM of the Kyoto Protocol / UNFCCC framework;
3. Agreement on liability and accountability mechanisms across national boundaries; and
4. Financial policy mechanisms to incentivize investment by private industry.

The new Kyoto Protocol agreement is still in progress, and the probability of CCS inclusion is unknown. Meanwhile, countries are exploring regulation frameworks and financial mechanisms, though the development of these is largely contingent upon stable policy. The following discussion details current knowledge.

Kyoto Protocol and CCS

The Kyoto Protocol is a legally binding agreement for its 184 signatory members that are parties to the United Nations Framework Convention on Climate Change (UNFCCC) (UNFCCC, 2009c). The UNFCCC objective is the "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system" (UNFCC, 2009c). Once the Kyoto Protocol expires in 2012, the UNFCCC must create a more stringent structure to assure compliance with climate change amelioration pledges. The COP15 meeting in Copenhagen (AKA the 15th Conference of the UNFCCC 192 Parties) sought to produce a replacement protocol, but so far only the Copenhagen Accord has been signed which calls for a ceiling on climate change at 2° C (Pershing, 2010).

Mechanisms and Challenges to CCS Inclusion

There are three interconnecting mechanisms under the Kyoto Protocol that support technology transfer via economic tools: the Clean Development Mechanisms (CDMs), Joint Implementation (JI), and Carbon Emission Trading (UNFCCC, 2010). CDMs are alternative energy projects meant to allow countries a "cleaner" way of developing, and they receive bilateral investment under Joint Implementation (CDM Executive Board, 2009). The countries implementing the projects also receive certified emission reduction permits (CERs) (UNFCCC, 2010).

According to the CDM website, the UNFCCC has considered CCS for incorporation into the CDM since 2005 (UNFCCC, 2009a). A variety of impediments have precluded CCS's official adoption, such as project boundary, leakage, and permanence, *inter alia* (UNFCCC, 2009b). Although the UNFCCC created draft decisions at the COP15 to include CCS as a CDM, discussion is ongoing as to whether CCS fits within the mission of Kyoto Protocol mechanisms among the other aforementioned concerns (UNFCCC, 2009d). The Executive Board has requested that baseline and monitoring methodologies be placed on hold until the supreme governing body of the UNFCCC (the COP) provides further guidance on the inclusion of CCS in the CDM (UNFCCC, 2009d). Their report categorizes the various obstacles as technical, environmental, methodological, legal, and market issues (CDM Executive Board, 2009).

While the mechanisms provide an accountability structure for countries to work together to achieve the Protocol's objective, compliance is not always transparent. Articles 7 and 8 require a national inventory of anthropogenic sources be maintained subject to review by expert teams (Redgwell, 2008). However, developing countries' commitments to these accountability measures has been controversial, and COP7 at Marrakesh in 2001 established an agreement on "new guidelines requiring developing country parties to report on their emissions and to indicate the steps being taken to meet their obligations under the UNFCCC" (Redgwell, 2008, p. 91).

The lack of transparency and compliance has deterred countries like the United States and Australia from ratifying the treaty in the past, and stronger mechanisms must be in place before any international cooperation on CCS, due to its risk factors and high capital costs. Currently Parties to the UNFCCC have doubted the effectiveness of CCS as an optional part of these mechanisms for these reasons as well as developing countries' financial problems and low technical capacity.

Developing countries have low profiles in CCS deployment because of financing and technical support challenges. CSS deployment is too expensive for most developing countries to fund their own projects. As previously mentioned, the CDM is the current international funding mechanism under UNFCCC, but it has not yet adopted CCS into the mechanism (IEA, 2009b). Thus, developing countries' CCS deployment is limited to small-scale projects unless outside funding and aid is procured.

Of notable concern in this debate is the amount of capital investment necessary in regions that do not currently comply with oversight and accountability measures for other international projects. Although technology transfers will be important for CCS development, these oversight and accountability issues must be addressed for effective development of the technology. Nevertheless, the future of any coherent international policy on CCS is at a standstill until the various parties to the UNFCCC can adequately address these concerns.

Emerging Regional and Bi-lateral Agreements

While global endorsement of CCS through the UNFCCC is delayed, a number of countries have forged regional/multilateral agreements and are actively pursuing a larger role for CCS in the portfolio of climate change management. These initiatives will most likely be more effective in integrating CCS into the global system as a bottom-up approach to policy development and implementation.

There are several international collaborative institutions to facilitate deployment of CCS. First, the Carbon Sequestration Leadership Forum (CSLF) is a ministerial-level international climate change initiative consisting of 24 members including 23 countries and European Commission. Its projects focus on information exchange and networking, planning, and road-mapping, facilitation of collaboration, and research and development (Carbon Sequestration Leadership Forum, 2008)

Second, the International Energy Agency (IEA) Greenhouse Gas R & D Program (IEA GHG) works on technology evaluation, facilitation of implementation, dissemination of the result and data from evaluation studies, international collaborative research, development, and demonstration (IEA, 2009a).

Third, the Global Carbon Capture and Storage Institute (GCCSI) supported by 20 national governments and over 80 leading corporations, non-governmental bodies, and research organizations provide advice and insight on technologies, economic, and legal aspects of CCS deployment.

Fourth, the COACH project between the European Union and China aims to prepare the implementation of large scale clean coal energy production in China. COACH develops a strong partnership between the countries while including public awareness/acceptance, legal, regulatory, and economic aspects (The COACH project, 2010).

International Cooperation with the United States

The Clean Energy Fossil Energy Task Force of the Asia-Pacific Partnership (APP) on Clean Development and Climate is a public-private task force to address climate change between the United States and Asian countries, such as China and Korea. NETL and the Korea Institute of Energy Research (KIER) have collaborated on CCS through joint research and development publications, exchanges of personnel and equipment, and collaborative meetings/workshops (Asia-Pacific Partnership on Clean Devlopment and Climate Change, 2008).

The World Resources Institute (WRI) and Tsinghua University have a project to build China's capacity to deploy CCS funded by the U.S. Department of State under APP; it aims to support regulatory framework of CCS in China. The WRI-Tsinghua team is drafting guidelines for safe and effective CCS in China. The process will engage diverse stakeholders and technical experts and help build consensus by sharing best practices (Asia-Pacific Partnership on Clean Devlopment and Climate Change, 2008).

China and the United States

The United States and China are the world's largest greenhouse gas emitters; therefore, collaboration between the two nations offers the greatest opportunity for achieving reductions in global greenhouse gas emissions. One critical pathway is supporting CCS to curb fossil fuel atmospheric emissions (Gallagher, 2009). Nevertheless, the policy attitudes between the two countries differ. China's perspective on CCS is that it can be an important carbon management tool, but it cannot become the priority area in developing countries, given the high cost and energy penalty of its large-scale development. Currently only a few memoranda of agreement have been signed (The Center for American Progress, 2009).

Thus, to promote the development of CCS, there must be broad international collaboration to improve the financial mechanism in technology development and transfer (Peng, 2009). Furthermore, there is no detailed national carbon storage assessment in China. Many people within Chinese government circles remain uncertain about the economic value of removing carbon dioxide from the process of burning coal. A government official reported, "We are willing to go along with international research, but [CCS] isn't currently our main focus when it comes to cutting emissions" (Stanway, 2010).

A successful U.S.-China collaboration should be built on mutual respect and recognition of both countries' expertise and incentives. It should also lay the track for substantial emission abatement and be able to evolve and grow in long term. The following are three recommendations made by the Center for American Progress. First, demonstrations of geologic carbon storage for existing low cost, pure streams of CO_2 are needed in China. Second, the U.S. could spearhead new collaborative research and development projects by comparing conventional coal-fired power plant technologies between the two countries. Third, the U.S. should catalyze markets for CCS by establishing mechanisms that encourage companies to store carbon. These suggestions outline a process that could yield early milestones while working toward the longer-term goals of retrofitting existing plants and developing new financing structures (The Center for American Progress, 2009).

The European Union and the United States

The Europe Commission has identified two tasks for deployment of CCS within the E.U. One is to develop an enabling legal framework and economic incentives for CCS. Another is to encourage the network of demonstration plants across the E.U. and other countries (European Commission, 2010a). The enabling legal framework for CCS includes:

1. Manage risks associated with CCS by ensuring that CO_2 is stored in safe sites;
2. Remove unwarranted barriers to CCS in existing legislation such as international conventions;
3. Examine the issues about long-term liability for the storage site; and
4. Improve communication to the public and stakeholders on the risks (European Commission, 2010a).

Developing a network of demonstration projects includes considering economic factors that increase capital investment, and the increased operating costs needed to run plants. There is also discussion of the treatment of CCS under the E.U. Emissions Trading Scheme (ETS). Currently, the E.U. is assisting with demonstration projects across Europe and internationally to deploy a range of technologies over the next 10-15 years (European Commission, 2010a).

In November 2009, the E.U.-U.S. Summit Declaration committed the countries to promote an international climate change agreement, aiming at a global goal of 50% global emissions reductions by 2050 (European Commission, 2009). The E.U.-U.S. Summit also discussed the establishment of new energy cooperation between the E.U. and the U.S. The Declaration established an E.U.-U.S. Energy Council at the ministerial level focused on studying diversification of energy sources; discussing effective promotion of global energy security; and fostering energy policy cooperation- bilaterally and with developing countries (Climate-L, 2009).

Workshops on CCS among the Atlantic Community

The business community, governmental organizations, and NGOs from both sides of the Atlantic have initiated a variety of CCS workshops, such as the Atlantic Council and the Clingendael International Energy Program. The report issued by the workshop pointed out that emission targets are more reasonable only if timely progress is made in deploying these basic CCS technologies on a massive scale. It also recommended that CCS plans be broadly supported by industry and the public. The report confirms that government-to-government dialogues are underway. It also said that a Transatlantic Forum or Council on Energy should be formed to coordinate an E.U.-U.S. energy cooperation (The Atlantic Council and the Clingendael International Energy Program, 2009).

Emerging Regulations

Regulatory frameworks for CCS are under current development within individual countries worldwide and will be essential to international CCS deployment. The best way to create these frameworks is to build upon existing national legislation, such as that for air pollution control, environmental impact assessment, and existing pipeline transport. There are patterns seen amongst countries as they explore these issues and lessons learned. For example, ensuring environmental integrity will require individual site-by-site assessment of CCS development including risk assessment, site characterization, simulation, and monitoring structures (Odeh and Haydock, 2009). Table 12 compares current regulatory frameworks across the European Union, the United Kingdom, the United States, and Australia. Check-marks indicate consideration of the category, while Xs indicate no consideration or lack of data available.

Table 12: Review of Regulatory Frameworks for CCS Development

Category	EU	UK	US	Australia
CO_2 capture discussed?	√	√	√	x
CO_2 transport discussed?	√	√	√	x
Details on exploration permits given?	√	√	√	√
Details on site characterisation given?	√	√	√	√
Site Certification and Storage Permits	√	√	√	√
Risk Assessment details given?	√	√	√	√
Classification of CO_2 referred to?	√	√	√	√
Details of CO_2 composition given?	x	X	x	x
Access, Property Rights and Ownership discussed?	√	√	√	√
Site Operation and Closure discussed?	√	√	√	√
Limits on injection pressure specified?	x	X	√	x
Details of parameters to be monitored post-closure given?	x	X	x	x
Post-closure, transfer of responsibility and Liability Issues discussed?	√	√	√	√
Transfer of responsibility period recommended?	x	X	√	√
MMV requirements given?	√	√	√	√
MMV specifications (accuracy of instruments and acceptable parameter ranges)?	x	X	x	x
IPR issues addressed?	x	X	x	x
Financial Issues addressed?	√	√	√	√

Odeh and Haydock, 2009

Marine Storage Treaties

In addition to terrestrial territory CCS storage regulation, there are several regulatory activities in legislations to protect marine environments. For example, the London Protocol prohibiting waste disposal in marine environments has been amended in 2006 and allows carbon dioxide to be sequestrated in sub-seabed geological formation (Odeh and Haydock, 2009). Disposal into sub-seabed formation should consist of overwhelmingly carbon dioxide and wastes should not be added to the disposal. Thirty-seven parties have currently ratified the amended Protocol (Office for the London Convention and Protocol, 2007).

Similarly, the Oslo-Paris (OSPAR) Convention regulating polluting activities in sub-seabed and subsoil introduced an amendment to allow for carbon dioxide storage in sub-seabed formation in 2007. It requires specific CO_2 guidelines be applied before a storage permit is issued. The guidelines focus on the process of injection and post injection and include site selection, characterization, risk assessment, and monitoring requirement (Odeh and Haydock, 2009). The amendment has yet to be ratified.

Intellectual Property Rights

CCS is a technology-intensive process; therefore copyright laws protecting existing and future technologies are an important legal aspect to the implementation of CCS. The transfer of intellectual property rights (IPRs)[3] is an issue that has been raised between the governments of developed and developing countries. Nevertheless, it remains unclear whether the CCS intellectual property owners (usually developed countries) will be willing to license them, especially in the absence of a stringent regulatory framework.

Currently, no specific IPR legal regime has been developed, although the World Trade Organization's Trade-Related Aspects of Intellectual Property Rights (TRIPs) agreement could serve as a stepping stone for CCS IPR development. Yet, there is no guarantee that developed countries will be willing to transfer or license their technology to developing countries (U.S. DOE/NETL, 2006).

International Public Perception

Universities and environmental research centers in a number of countries outside of the U.S. have conducted studies regarding the public's view of CCS. The first common result of these studies is that awareness and knowledge of CCS is generally very low. For example, in public opinion surveys conducted in the UK, Sweden, and Japan, "carbon capture and storage" and "carbon storage" received the lowest recognition among a range of technologies including wind energy, energy efficient appliances, nuclear energy, and biomass. The second result is that although the common reaction is skepticism, there seems no a priori rejection of the technology (Reiner et al., 2006).

The potential risks of CCS help explain public rejection. In France, for example, the question about 'approval of or opposition to' the use of CCS was asked two times: first after

[3] IPR are temporary grants of monopoly intended to give economic incentives for innovative activity.

presenting the technology, and then soon after explaining the possible risks. The approval rates were 59% and 38%, respectively (Pagnier, 2007). On the other hand, other factors such as the source of information, level of trust in key institutions, and confidence in the government were significant in the public opinion survey on CCS. For example, a Japanese survey provided different information on CCS to each group of participants; the group that received information from neutral newspaper articles returned slightly lower preference levels than the group that received information from the IPCC Special Report (Itaoka, Okuda, Saito, and Akai, 2009).

The results of these surveys also show that respondents generally perceive CCS as a bridge technology to a more sustainable future. A study in the United Kingdom by the Tyndall Centre, one of the leading research centers on climate issues, found that compared with other mitigation options, renewable energy and energy efficiency were more strongly favored. However, CCS was still preferred over nuclear power or higher energy bills (Shackley, McLachlan and Gough, 2005). In this sense, CCS is tolerable when framed as part of a range of measures and as an alternative to nuclear power (Pagnier, 2007). It can also be inferred that larger increases in electricity prices due to CCS technologies could be an important handicap for the CCS deployment in the U.S.

Finally, the E.U.'s ACCSEPT Project is an important source for anticipating how NGOs will respond to deployment of CCS technology in the U.S. The results of surveys conducted throughout the E.U. show that NGOs are the least accepting of CCS among potential stakeholders (e.g. energy industry, research/government sectors, and national parliaments). The NGO respondents were concerned about the potential risks and potential negative impacts of CCS upon investment in other low- and zero-carbon energy technologies, energy efficiency, energy demand reduction, and movement towards a decentralized power generation system (Shackley et al., 2007).

Concluding Comments

Although a variety of policy options are under active consideration, the role of CCS in a carbon management portfolio is likely to be contingent upon strong political leadership and available funding to assist industry in complying. While President Obama is supporting R and D domestically, the current global recession is a hindrance to commercial development domestically and especially internationally.

Chapter IX: Conclusions

Technologies and Costs

Overall, CCS proves to be a cost competitive option that results in low-carbon electricity generation as part of a larger carbon management portfolio. Specifically, we found that CCS increases the levelized COE by 1.3¢ to 2.2¢ per kWh depending on the technology used. However, federal funding for research, development, and deployment will be essential to implement CCS on a commercial scale.

According to the data presented in this report and given the projected coal usage throughout the next 50 years, IGCC plants are the most practical for immediate application of CCS at new facilities. IGCC technology is better developed than oxyfuel combustions techniques, and upgrading an existing IGCC plant to include capture technology provides the lowest marginal increase in levelized COE. We find that IGCC is the first fossil fuel technology to be economical with capture at a price of $22 per tonne of CO_2.

NGCC technology is also practical for immediate implication of CCS as it is more developed than other technologies and would be able to move from pilot-scale to commercial-scale projects given the proper incentives. Furthermore, NGCC provides the lowest levelized COE (assuming a stable price of natural gas at $4.50/MMBtu) of all the fossil fuels technologies across all carbon prices, second only to oxy-fuel ultra supercritical. If the price of natural gas were to increase significantly relative to coal, NGCC's levelized COE would become greater in comparison to all other coal based technologies, thereby making it a less competitive option (also see Appendix A).

Federal funding for research and development would be best placed in oxyfuel technologies, particularly ultra supercritical. Given the projection that coal will remain a heavily used fuel source for at least the next 50 years resulting in continued environmental concerns regarding CO_2 emissions, oxyfuel sources show the greatest potential for future power generation reliance. Our analysis suggests that oxyfuel ultra supercritical technology has the lowest levelized COE of all of the fossil fuel technologies with capture at any CO_2 price. It is also specifically designed to produce zero CO_2 emissions during coal combustion. The COE increases with coal based technologies when there is a price on CO_2; however, because oxy-fuel produces zero carbon dioxide emissions, it remains the most cost competitive option as its levelized COE remains stable among all prices of CO_2 . However, as oxy-fuel technologies are still in early development stages, heavy federal investment in research and development will be needed in order to bring this technology to commercial-scale.

According to this analysis, nuclear plants provide substantially lower levelized COE at every price of CO_2. Due to the low COE that nuclear power provides, it may become a more widely utilized power-generating source; however, high initial capital costs, and concerns about long-term radioactive waste disposal may deter its rapid growth in the short term.

According to sensitivity analyses, when both production and investment tax credits are available, the levelized COE for wind technology using NGCC with capture for backup power becomes less than or equal to that of most other coal technologies. Also, as power generation via wind technology creates far less CO_2 emissions than with regular fossil fuel technologies, the levelized COE produced by on-shore wind (with NGCC plus capture as backup) becomes even less than that of other fossil fuel technologies as a higher cost of CO_2 is introduced. Therefore, if a cost of CO_2 is introduced in the market, wind-NGCC with capture technology as a power generation source will become increasingly cost competitive since it emits less CO_2. Of course, while these tax credits to electricity producers reduce the out of pocket cost of electricity to consumers, those same consumers are the taxpayers who will pay for the tax credits.

Legal

A legal framework including a time frame for financial responsibility of site injection is necessary to implement CCS technologies. Currently, underground injection is regulated by the SWDA, through the UIC program. Only five classes of injection substances exist, therefore in July 2008, the U.S. EPA proposed "Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells Proposed Rule." This rule would add a sixth class, specifically addressing CO_2 storage. The primary purpose of the proposed rule is the protection of underground source drinking water, including the proper plugging and monitoring of all onsite wells. In ensuring the protection of USDW, it will also prevent other potentially negative human health and environmental consequences. Moreover, a CCS legal framework should include surface and subsurface property rights and liability laws regulated by the federal government. It is important to future CCS programs that this proposed rule is passed in order to provide the necessary legal framework.

Public Perception

A CCS public outreach program should keep the public and local community informed about their actions and intentions. This type of transparency would encourage facilities to maintain integrity of operation, possibly leading to greater community acceptance. This may be established through distributions of educational materials at the community level. In addition, facilities should be required to record actions on a website delineating all aspects of its CCS program. It is advisable for utilities to assign a point person to field questions and concerns from community members. Community meetings would also improve communications between a utility and local residents on an individualized basis. These and other community relations tactics are advisable.

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Appendices

Appendix A: Cost Analysis Tables

Fuel Prices:
Natural Gas = $4.50/MMBtu
Coal = $1.55/MMBtu
Uranium = $.067/MMBtu
Note: Fuel prices and power generation system lifetimes are based on current numbers and projections. Investment tax credits (ITC) and production tax credits (PTC) are based on current levels of tax credits by the federal government.

Table A-1a: Levelized Cost of Electricity Over Time for Fossil Fuel Technologies ($/kWh)

Level playing field, 5% Discount Rate, $0/tonne CO_2	IGCC		NGCC		Subcritical PC		Supercritical PC		Oxy Fuel	
	without Capture	with Capture	without Capture	with Capture	without Capture	with Capture	without Capture	with Capture	Super	Ultra
20 years	0.048	0.063	0.039	0.054	0.041	0.065	0.040	0.067	0.064	0.057
30 years	0.044	0.038	0.038	0.051	0.038	0.059	0.037	0.061	0.058	0.052
50 years	0.041	0.054	0.035	0.049	0.035	0.055	0.035	0.057	0.054	0.048

Table A-1b: Levelized Cost of Electricity Over Time for Fossil Fuel Technologies ($/kWh)

Level playing field, 10% Discount Rate, $0/tonne CO_2	IGCC		NGCC		Subcritical PC		Supercritical PC		Oxy Fuel	
	without Capture	with Capture	without Capture	with Capture	without Capture	with Capture	without Capture	with Capture	Super	Ultra
20 years	0.059	0.077	0.042	0.060	0.049	0.081	0.049	0.083	0.078	0.071
30 years	0.055	0.073	0.041	0.058	0.047	0.076	0.046	0.078	0.073	0.067
50 years	0.054	0.071	0.041	0.057	0.046	0.074	0.045	0.076	0.071	0.065

Table A-2a: Levelized Cost of Electricity Over Time for Alternative Power Generation Options ($/kWh)

Level playing field, 5% Discount Rate	Nuclear	Wind				Solar	
		On-Shore	On-Shore with NGCC	On-Shore with NGCC with Capture	Off-Shore	Photo-voltaic	Thermal
20 years	0.044	0.060	0.050	0.059	0.084	0.224	0.126
30 years	0.036					0.183	0.106
50 years	0.031					0.165	0.096

Table A-2b: Levelized Cost of Electricity Over Time for Alternative Power Generation Options ($/kWh)

Level playing field, 10% Discount Rate	Nuclear	Wind				Solar	
		On-Shore	On-Shore w/ NGCC	On-Shore with NGCC with Capture	Off-Shore	Photo-voltaic	Thermal
20 years	0.061	0.083	0.065	0.077	0.113	0.326	0.177
30 years	0.056					0.295	0.162
50 years	0.053					0.285	0.157

Table A-3a: Effects of Carbon Price on Levelized Cost of Electricity for Fossil Fuel Technologies ($/kWh)

Level playing field, 5% Discount Rate, 50 years	IGCC		NGCC		Subcritical PC		Supercritical PC		Oxy Fuel	
	without Capture	with Capture	without Capture	with Capture	without Capture	with Capture	without Capture	with Capture	Super	Ultra
$0/tonne CO_2	0.041	0.054	0.035	0.049	0.035	0.055	0.035	0.057	0.054	0.048
$25/tonne CO_2	0.061	0.057	0.044	0.051	0.057	0.058	0.055	0.060	0.054	0.048
$50/tonne CO_2	0.081	0.059	0.052	0.052	0.078	0.061	0.075	0.063	0.054	0.048
$100/tonne CO_2	0.121	0.064	0.069	0.054	0.121	0.067	0.115	0.068	0.054	0.048

Table A-3b: Effects of Carbon Price on Levelized Cost of Electricity for Fossil Fuel Technologies ($/kWh)

Level playing field, 10% Discount Rate, 50 years	IGCC		NGCC		Subcritical PC		Supercritical PC		Oxy Fuel	
	without Capture	with Capture	without Capture	with Capture	without Capture	with Capture	without Capture	with Capture	Super	Ultra
$0/tonne CO_2	0.054	0.071	0.041	0.057	0.046	0.074	0.045	0.076	0.071	0.065
$25/tonne CO_2										
$50/tonne CO_2										
$100/tonne CO_2										

Table A-4a: Effects of Carbon Price on Levelized Cost of Electricity for Alternative Power Generation Options ($/kWh)

Level playing field, 5% Discount Rate	Nuclear	Wind				Solar	
		On-Shore	On-Shore with NGCC	On-Shore with NGCC with Capture	Off-Shore	Photo-voltaic	Thermal
$0/tonne CO_2	0.031	0.060	0.050	0.059	0.084	0.183	0.106
$25/tonne CO_2	0.031	0.060	0.057	0.063	0.084	0.183	0.106
$50/tonne CO_2	0.031	0.060	0.061	0.063	0.084	0.183	0.106
$100/tonne CO_2	0.031	0.060	0.070	0.064	0.084	0.183	0.106

*Nuclear COE is based on 50 year lifetime
**Wind COE is based on 20 year lifetime
***Solar COE is based on 30 year lifetime

Table A-4b: Effects of Carbon Price on Levelized Cost of Electricity for Alternative Power Generation Options ($/kWh)

Level playing field, 10% Discount Rate	Nuclear	Wind				Solar	
		On-Shore	On-Shore w/ NGCC	On-Shore with NGCC with Capture	Off-Shore	Photo-voltaic	Thermal
$0/tonne CO_2	0.053	0.083	0.065	0.077	0.113	0.295	0.162
$25/tonne CO_2							
$50/tonne CO_2							
$100/tonne CO_2							

*Nuclear COE is based on 50 year lifetime
**Wind COE is based on 20 year lifetime
***Solar COE is based on 30 year lifetime

Table A-5: Levelized Cost of Electricity for Fossil Fuel Technologies with Subsidies ($/kWh)

Level playing field, 5% Discount Rate, 50 years, $0/tonne CO_2	IGCC		NGCC		Subcritical PC		Supercritical PC		Oxy Fuel	
	without Capture	with Capture	without Capture	with Capture	without Capture	with Capture	without Capture	with Capture	Super	Ultra
Investment Tax Credit	0.041	0.049	0.035	0.047	0.035	0.049	0.035	0.051	0.049	0.043
Production Tax Credit	0.041	0.046	0.035	0.041	0.035	0.046	0.035	0.048	0.045	0.039
ITC + PTC	0.041	0.041	0.035	0.039	0.035	0.041	0.035	0.043	0.040	0.034

*Investment Tax Credit=25% of Capital
**Production Tax Credit=$0.02/kWh for 10 years

Table A-6: Levelized Cost of Electricity for Alternative Power Generation Options with Subsidies ($/kWh)

Level playing field, 5% Discount Rate, $0/tonne CO_2	Nuclear	Wind				Solar	
		On-Shore	On-Shore with NGCC	On-Shore with NGCC with Capture	Off-Shore	Photo-voltaic	Thermal
Investment Tax Credit	0.025	0.048	0.046	0.053	0.068	0.139	0.083
Production Tax Credit	0.023	0.048	0.046	0.050	0.071	0.173	0.096
ITC + PTC	0.016	0.035	0.040	0.041	0.055	0.129	0.073

*Nuclear COE is based on 50 year lifetime
**Wind COE is based on 20 year lifetime
***Solar COE is based on 30 year lifetime
****Investment Tax Credit=25% of Capital
*****Production Tax Credit=$0.02/kWh for 10 years

Table A-7: Levelized Cost of Electricity for Fossil Fuel Technologies with Subsidies ($/kWh)

Level playing field, 5% Discount Rate, 50 years, $100/tonne CO_2	IGCC		NGCC		Subcritical PC		Supercritical PC		Oxy Fuel	
	without Capture	with Capture	without Capture	with Capture	without Capture	with Capture	without Capture	with Capture	Super	Ultra
Investment Tax Credit	0.121	0.059	0.069	0.051	0.121	0.062	0.115	0.063	0.049	0.043
Production Tax Credit	0.121	0.055	0.069	0.045	0.121	0.059	0.115	0.060	0.045	0.039
ITC + PTC	0.121	0.050	0.069	0.043	0.121	0.053	0.115	0.054	0.040	0.034

*Investment Tax Credit=25% of Capital
**Production Tax Credit=$0.02/kWh for 10 years

Table A-8: Levelized Cost of Electricity for Alternative Power Generation Options with Subsidies ($/kWh)

Level playing field, 5% Discount Rate, $100/tonne CO_2	Nuclear	Wind				Solar	
		On-Shore	On-Shore with NGCC	On-Shore with NGCC with Capture	Off-Shore	Photo-voltaic	Thermal
Investment Tax Credit	0.025	0.048	0.064	0.055	0.068	0.139	0.083
Production Tax Credit	0.023	0.048	0.064	0.052	0.071	0.173	0.096
ITC + PTC	0.016	0.035	0.058	0.043	0.055	0.129	0.073

*Nuclear COE is based on 50 year lifetime
**Wind COE is based on 20 year lifetime
***Solar COE is based on 30 year lifetime
****Investment Tax Credit=25% of Capital
*****Production Tax Credit=$0.02/kWh for 10 years

Table A-9a: Levelized Cost of Electricity ($/kWh), Annual Increase in Natural Gas Price=2%

Level playing field, 5% Discount Rate, \$0/tonne CO_2	NGCC		Wind	
	without Capture	with Capture	On-shore with NGCC	On-shore with NGCC with Capture
	0.045	0.063	0.054	0.066

*NGCC COE based on 50 year lifetime
**Wind COE based on 20 year lifetime

Table A-9b: Levelized Cost of Electricity ($/kWh), Annual Increase in Natural Gas Price=2%

Level playing field, 10% Discount Rate, \$0/tonne CO_2	NGCC		Wind	
	without Capture	with Capture	On-shore with NGCC	On-shore with NGCC with Capture
	0.047	0.065	0.068	0.081

*NGCC COE based on 50 year lifetime
**Wind COE based on 20 year lifetime

Appendix B: Assumed Parameters Table

	Plant Size (MW)	Plant Cost ($/KW)	Capacity factor	Annual Fixed O&M ($/kW)	Annual Var. O&M ($/kWh)	Thermal efficiency	Annual Fuel Costs	Annual CO_2 emissions (MT)	Raw Water Usage (gpm/MW-net)
IGCC[1]	640.3	1937	80%	37.69	0.0069	0.382	62,054,247	3,572,000	6.3
IGCC + Capture[1]	555.7	2553	80%	46.73	0.0086	0.325	73,608,526	364,000	8.2
NGCC[1]	560.4	592	85%	10.49	0.0014	0.508	126,164,832	1,507,000	4.5
NGCC + Capture[1]	481.9	1249	85%	17.78	0.0027	0.437	126,172,840	151,000	8.1
Subcritical PC[1]	550.4	1655[1]	85%	26.36	0.0054	0.368[1]	58,924,227	3,506,000	11.3
Sub PC + Capture[1]	549.6	3093[1]	85%	39.93	0.0054	0.249[1]	87,052,684	517,000	22.2
Supercritical PC[1]	550	1682	85%	26.90	0.0052	0.391[1]	55,358,423	3,295,000	9.9
Super PC + Capture[1]	546	3064	85%	40.14	0.0096	0.272[1]	78,983,625	468,000	19.1
OxyFuel Super[1]	550	2842	85%	36.66	0.0070	0.293	73,982,618	0	10.6
OxyFuel Ultra[1]	550	2780	85%	36.06	0.0066	0.33	65,717,893	0	13.5
Nuclear	1350[2]	3820[2]	92%	5.78	0.00051[2]	45%	53,311,608	0	6.4[1]
Wind (on-shore)	50[2]	1837[2]	34%[3]	30.98[2]	0[2]	n/a	0	0	
Wind (on-shore with NGCC)*	610.4	2429	84%	17.19	0[2]	0.508	74,214,607	886,470	4.1[1]
Wind (on-shore with NGCC and Capture)*	531.9	3086	84%	10.31	0[2]	0.437	74,219,318	88,824	7.3[1]
Wind (off-shore)	100[2]	3492[2]	50%[4]	86.92[2]	0[2]	n/a	0	0	
Solar (PV)	5[2]	5879[2]	25%[4]	11.94[2]	0[2]	n/a	0	0	
Solar (Thermal)	100[2]	4798[2]	40%[4]	58.05[2]	0[2]	n/a	0	0	

Assumptions for this table include: costs in 2008 US$, 5% discount rate, 90% carbon capture rate for all CCS technologies (except 100% with oxyfuel); $1.55/MMBtu coal cost; $4.50/MMBtu natural gas cost, $0.67/MMBtu uranium cost
*Combined capacity factor of 84% based on 34% wind capacity factor and NGCC facility operating in load-following dispatch at 50% capacity factor.
Sources include:[1]NETL (2007) [2]DOE - module, 2010 [3]Logan and Kaplan, 2008 [4]EIA - module, 2010

Appendix C: Breakdown of Capture Technologies

Technology		Description	Stage	Advantages	Disadvantages	Where	When	Cost Estimates	Source
Post-combustion	Amine-Based wet scrubbing (MEA system)	Absorb CO_2 with monoethanolamine (MEA) solvent	Ready in use	High capture efficiency	Relatively expensive		since 1930s	$154/MWh,+80% (Levelized Cost of Electricity)	(NETL, 2010)
					High requirement of energy and water				
				Applicable to existing plants	Prior Contaminants (SO_2, NO, CH) need removing				
				Commercially available	No economic incentive and legal responsibility				
					Not tested at greater than a 500MW scale				
	Ionic Liquids	ionic liquids absorb CO_2	Lab	Lower costs	Early development phase: scale up needed			$126/MWh,+47% (Levelized Cost of Electricity)	(NETL, 2010)
				Lower heat requirements					
	Carbonates	react CO_2 and soluble carbonate to form a bicarbonate	Lab	Lower heat requirements	Early development phase: scale up needed	Univ. Texas Austin		$118/MWh,+37% (Levelized Cost of Electricity)	(NETL, 2010)
				Tolerant of SO_2					
				Lower costs					
	Metal Organic Framework	Hybrid organic/inorganic structure with optimized cavities	Lab	High storage capacity	Moisture and Contaminant sensitive			$128/MWh,+50% (Levelized Cost of Electricity)	(NETL, 2010)
				Lower heat requirements					
	Solid Amines (dry scrubbing)	Amine based solid absorbs CO_2	Pilot test	Lower water and energy requirements					
	Membrane capture system	permeable or semi-permeable materials allow selective transport to separate CO_2	Pilot test	Cost reduction relevant with absorbing system	Early development phase: scale up needed		Jan. 2010	$124/MWh,+40% (Levelized Cost of Electricity)	(NETL, 2010)
				No chemical reaction					
				No moving parts					

Technology		Description	Stage	Advantages	Disadvantages	Where	When	Cost Estimates	Source
Oxy-combustion	usual oxy-combustion	Coal is combusted in an oxygen rich environment (>95%)	in use	Step-change reduction in CO_2 separation and capture cost	Changing boiler and turbine material (high temp)			Reduce $37/ton CO2	(Figueroa et al., 2008)
				60-70% reduction in NOX (flue gas recycling)	Increasing energy need				
				Reduction in Mercury emission	High capital cost (air separation unit)				
				Readily applied to new coal power plants	Uncertainty in technology				
	chemical looping	Oxygen is supplied by a solid oxygen carrier	Research needed	No oxygen plant needed	Membrane and air separation uint development needed			Increased COE <+20%	(Ciferno, 2010)
				Potential lowest cost option	Oxygen carrier material development needed				
Pre-combustion: Integrated Gasification Combined Cycle(IGCC)	In common	Coal slurry(coal +water) is reacted with CO_2 at a high temperature to make syngas, from which CO_2 is separated	In use	The most efficient way to capture pure CO_2	Existing power plants need to be retrofitted to syngas combustion	Four plant in the world		Change according to reduction goal and technology	
				More economical than post-combustion capture	Capture and syngas technology is expensive				
				Very low level of pollutant(SOX, NOX) and volatile mercury emission	ASU(Air Separation Unit) is expensive			$41.80~$51.19/ton CO2 to $50~$119ton/CO2	(EPRI, 2006)
					Parasitic energy loss(20-30%)				(Rubin, 2007) (Pew Center, 2006)
	Physical Solvents for Separation of CO_2	Physical solvents absorb CO_2 without chemical reaction	in use over 30 years	Efficient in capturing CO_2	Energy intensive			IGCC with no CO2 capture: Total Plant Cost(TPC) $1,900/kWe IGCC with CO2 capture: TPC $2,500/kWe	(NETLb, 2009)
					Expensive and capital intensive			COE +37% avoided CO2 cost $46/tonne	(NETLb, 2009)
	Membrane capture system	Use polymer-based or ionic liguid membrane to capture CO_2	Research needed	Less energy intensive	Not stable in IGCC condition			90% capture rate withk a parasatic power loss less than 10%	(Ciferno, 2010)
				Requires no phase change (temperature or pressure modification)	Susceptible to chemical degradation				
				Low maintenance fee					
	Pre-combustion solvents	CO_2 is filtered through porous materials at high temperatures and	Research needed	More energy efficient than chemical solvent					
				Little replacement needed					

Breakdown of Storage Options:

Type		Description	Stage	Advantages	Disadvantages	Where	When	Cost Estimates	Source
Geologic Storage	Oil and Gas reservoirs	Depleted oil or gas reservoirs can, in theory, hold carbon dioxide for extended periods of time. Enhanced Oil Recovery(EOR) has been been used since the 1970s.	Ready to use	well-developed	long-term storage is uncertain	West Texas (transported from New Mexico and Colorado via pipeline)	Since early 1970's	EOR: $73.84-($91.26)/tCO2	(Heddle et al., 2003)
				more efficient recovery of the resources				Depleted gas resorvoir: $1.20-$19.43/tCO2	(Heddle et al., 2003)
				less energy to power the oil recovery				Depleted oil resorvoir:$1.21-$11.16/tCO2	(Heddle et al., 2003)
				low risk (Proven technology)					
	Saline Formations	Use porous rock saturated with brine and capped with an impermeable rock formation.	Research needed	higher storage capacity (97% of total identified on-shore capacity)	uncertainty in storage capacity			$1.14-$11.71/tCO2	(Heddle et al., 2003)
				proximity to the source					
				abundant throughout the world					
				stability					
	Coal Seams	Use Enhanced Coal-Bed Methane (ECBM) recovery technology.	Research needed	lower net cost than EOR	uncertainty in storage capacity, geologic and reservior data, short and long-term interaction between coal and CO2, injection strategy			$18.88-$25.72/tCO2	(Heddle et al., 2003)
	Shale	Use organic materials found in shale formation to absorb CO2.	Research needed	abundant throughout the world	Hard to inject large volume of CO2				
	Basalt	Use basalt makeup to cnvert CO2 to "carbonate minerals."	Research needed	abundant throughout the world	low potential for leakage				

Appendix D: MIT Survey

Survey responses were used to answer the following questions:

- What are public attitudes toward global warming and climate change mitigation technologies?
- What is the level of public understanding of global warming and carbon dioxide capture and storage (or carbon sequestration)?
- What is the effect of information (national energy usage and price data) on public preference?
- What lessons do the survey results suggest for public outreach campaigns?[1]

Information given to survey participants regarding the cost of various energy sources:

- Using coal and natural gas, the typical family pays $1,200 per year for electricity.
- Using all nuclear power would emit no carbon dioxide and would increase electricity cost for families to $2,400 per year.
- Using carbon sequestration along with coal and natural gas would reduce carbon dioxide emissions by 90% and would also increase electricity costs to $2,400 per year.
- Using renewable (solar and wind power) would increase annual electricity costs to $4,000. [4]

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[4] Curry, Tom, D M Reiner, S Ansolabehere, and H J Herzog. *How Aware is the Public of Carbon Capture and Storage?* MIT Laboratory for Energy and the Environment, Cambridge, MA. Available at: http://knowledge.fhwa.dot.gov/cops/italladdsup.nsf/7ec05a279f17ed79852569590071284c/f8c06c26809445cf85256fce0066add6/$FILE/Greenhouse%20gas%20public%20awareness%20survey.pdf Accessed 3 February 2010.

Appendix E: Examples of Regional Market-based Initiatives

Region	Key Components	Participating States
Regional Greenhouse Gas Initiative (RGGI)	• Requires a 10% reduction below 2009 emissions levels by 2019 • Requires fossil fuel generation plants greater than 25 megawatts to purchase allowances per ton of emissions • Utilities with higher emissions can purchase allowances from utilities with lower emissions • Regional cap set at 188 million tons of CO2 (Regional Greenhouse Gas Initiative, 2010)	Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont
Western Climate Initiative	• Set to be fully implemented in 2015 • Requires a 15% reduction below 2005 emissions levels by 2020 (Environment Northeast, 2010) • Regulated sources will include: electricity generation, industrial process emissions, transportation, and residential/ commercial fuel consumption • Plan includes allowances that can be purchased at auction and offset credits (Western Climate Initiative, 2010)	Arizona, California, Montana, New Mexico, Oregon, Utah, Washington, and four Canadian Provinces: British Columbia, Manitoba, Ontario, and Quebec
Midwestern Greenhouse Gas Reduction Accord	• No official date has been set for implementation • Recommendations have been sent to the Governors of participating states • Recommends a 20% reduction below 2005 levels by 2020 and an 80% reduction by 2050 • Recommended sources include: electricity generation, industrial process and combustion sources, transportation, residential/ commercial fuel consumption • Reductions will be proportionate to each party's share of emissions (Midwestern Greenhouse Gas Advisory Group, 2009, p. 5-7)	Governors of Illinois, Iowa, Kansas, Michigan, Minnesota, Wisconsin, and the Premier of Manitoba

Appendix F: Overview of Bills/Acts of Emissions Policy at State Level

State	Emission Performance Standard Policy	How it Relates to CCS
California	In September 2006, the State of California outlined its EPS in SB 1368, which sets standards for net emissions that are not to exceed 1,100 pounds of carbon dioxide per megawatt-hour (Simpson and Hausauer, 2009).	This legislation allows for CCS insofar as proven effective and economically viable.
Washington	The State of Washington modeled SB 6001 after California's EPS 'thresholds' and enacted it in May 2007. Additionally, Washington mandates, in RCW 80-70-010 that all new fossil-fuel based power plants must mitigate twenty percent of total emissions (Simpson and Hausauer, 2009).	RCW 80-70-010 outlines three activities to meet its mitigation goal: (1) investment in carbon dioxide mitigation projects like CCS, (2) purchase carbon credits, (3) pay a third party to perform mitigation (Pew Center on Global Climate Change, 2010).
Oregon	Similar to the emission performance standards of Washington and California, the State of Oregon enacted SB 101 in July 2009 which mandates that electricity generators may emit no more than 1,100 pounds of green house gases per mega-watt hour. In addition, SB 101 mandates that utilities may not enter into long-term purchase agreements with base-load power generators that do not meet this 'threshold' standard (Pew Center on Global Climate Change, 2010).	This legislation does not explicitly refer to CCS, however the Oregon Department of Ecology is in the process of adopting directives for CCS (Washington State Department of Ecology, 2008, p. 189).
Montana	House Bill 25, signed in May 2007, sets emissions standards for new coal-fired power plants (Simpson and Hausauer, 2009).	New coal-fired plants are subject to sequestering fifty percent of their carbon emissions.
Illinois	The Clean Coal Portfolio Standard Law, or SB 1987, was enacted in January 2009. Similar to Montana's HB 25, this law sets emissions standards for new coal plants (Simpson and Hausauer, 2009).	SB 1987 sets up a timed framework for new coal plants to capture and store a progressive percentage in several year increments.

Bills/Acts Dealing with CCS at State Level

State	Description of Financial Incentive	Type of Financial Incentive
Colorado	Colorado Statute 40-2-123 of 2006 designates unspecified monies from the Colorado Clean Energy Fund to financial support for development of CCS (Cowart, et al, 2008, p. 33)	Grant
Minnesota	The 2009 statute 216B.1694 *Innovative Energy Project* offers grants to eligible projects in the amount of $2 million a year for five years (Minnesota Office of the Reviser of Statutes, 2010)	Grant
New Mexico	The 2007 *Advanced Energy Tax Credit* SB994 bill is the first tax credit in the U.S. to cover CCS technology, providing up to 6% of plant's expenditures – not to exceed $60 million – for development and construction (Goldstein, 2007)	Tax Credit

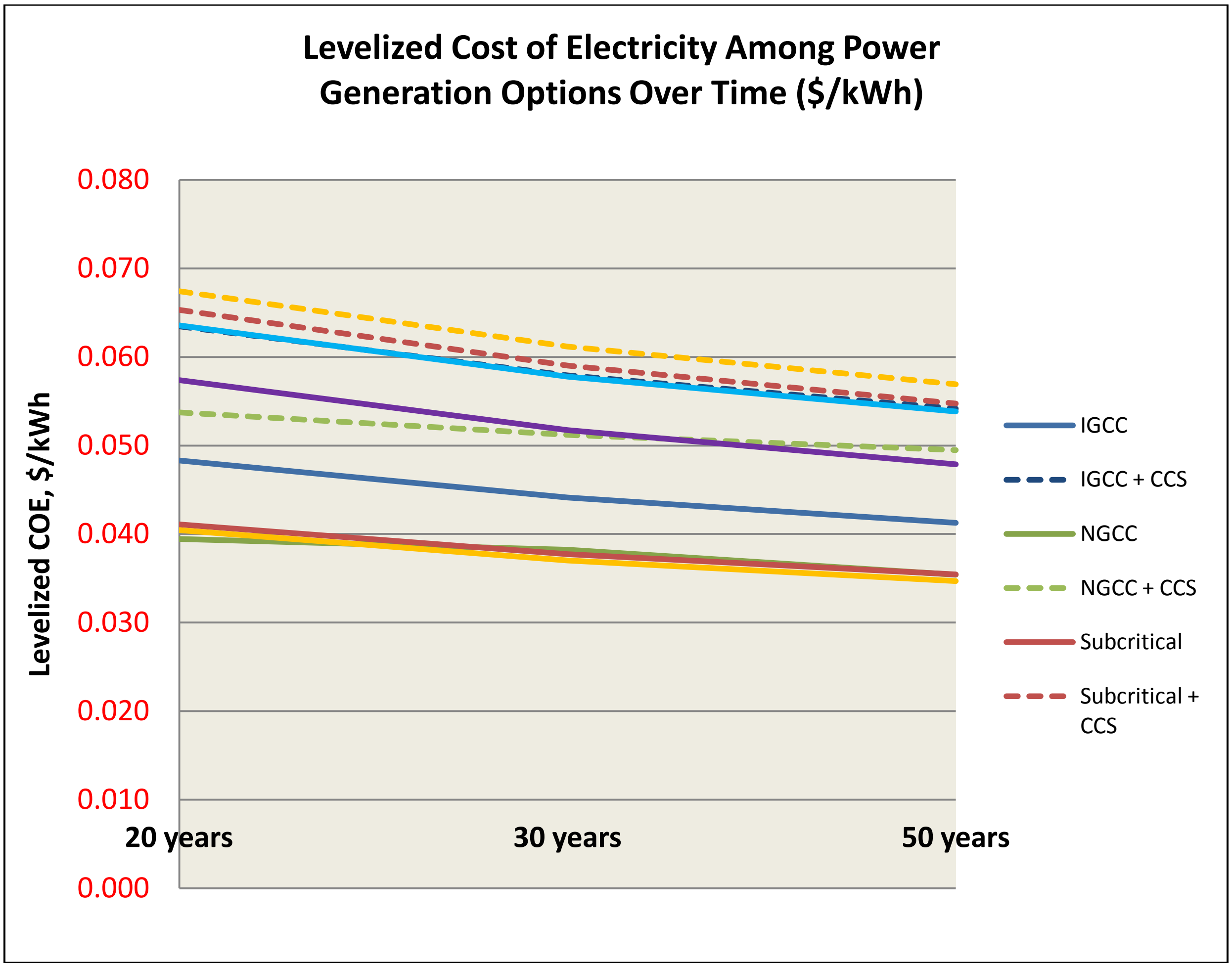
Overview of Bills/Acts Dealing with CCS at Federal Level

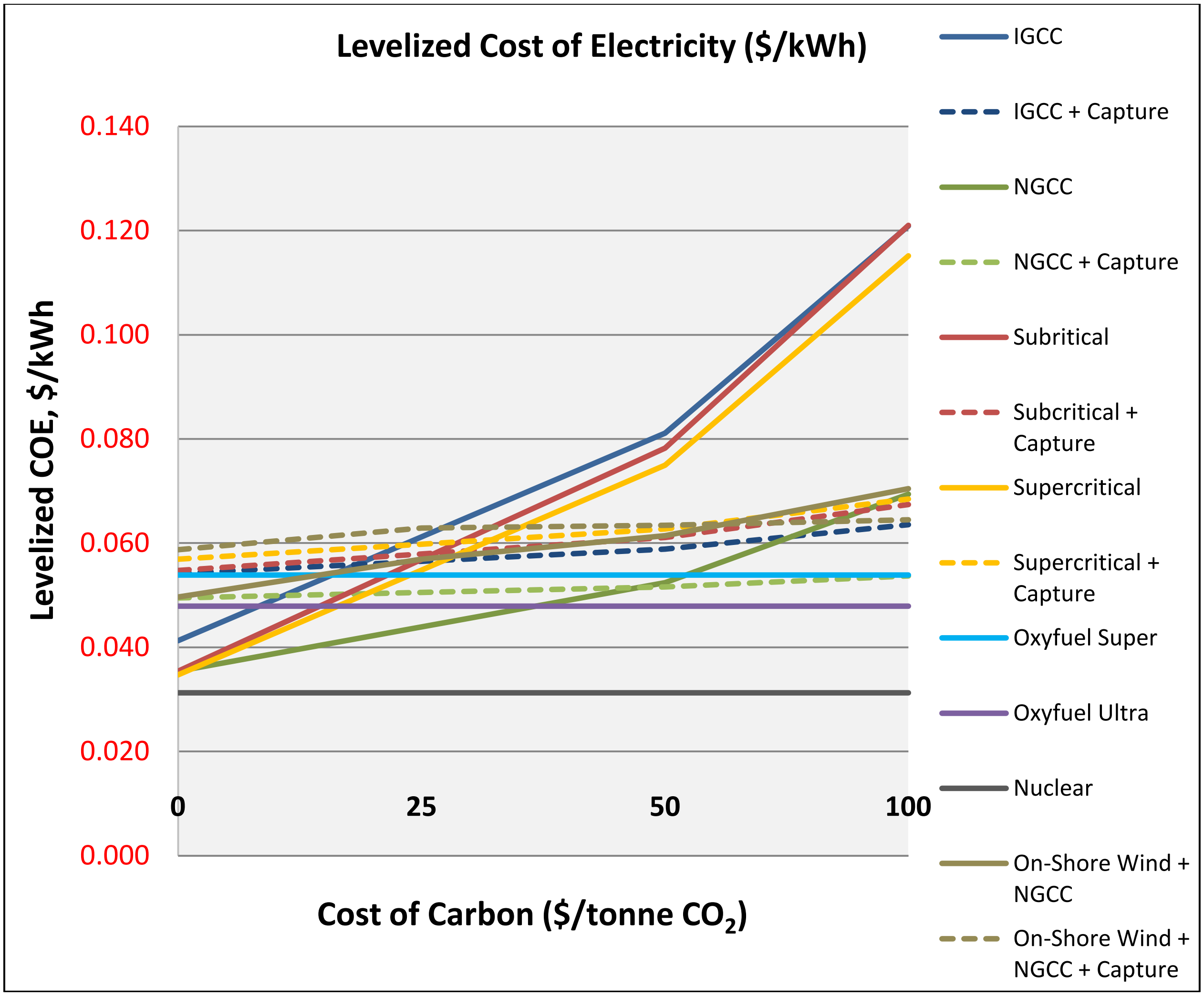
Act/Bill Name	How it Relates to Financial Incentives for CCS	Date Introduced/Passed
ARRA Rep. Obey (D-WI)	• Appropriates $3.4 billion to DOE for industrial carbon capture projects (Congressional Research Service, 2009)	Introduced: January 2009 Passed: Yes (February 2009)
ACES Rep. Waxman (D-CA)	• Provides direct payments to coal-fired power plants for carbon dioxide storage • Provides funding for 10 CCS demonstration projects not to exceed $1 billion/year (World Resources Institute, 2010) • Time segmented breakdown of coal plant permissions: • 2009 – 2015: Coal power generation plants lose financial assistance for failure to retrofit within 5 years • 2015 – 2020: Coal power generation plants lose financial assistance if CCS technologies were not implemented • 2020: Coal power generation plants must use CCS (CLEAR Act Side-by-Side with ACES, 2010, p. 4)	Introduced: May 2009 Passed: House (June 2009)

Appendix G: Additional Cost Analysis Illustrations

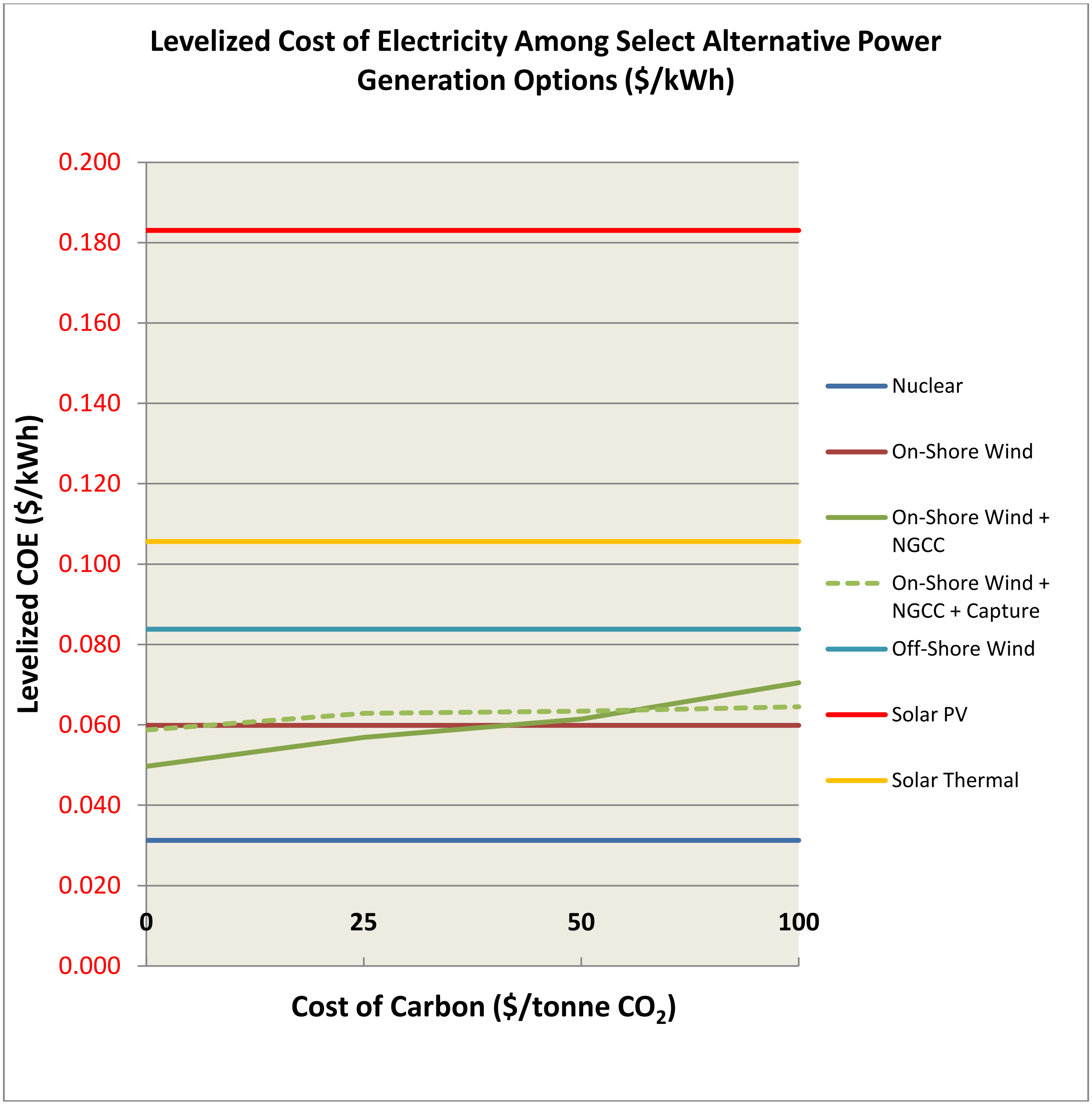
These tables include the following assumptions:

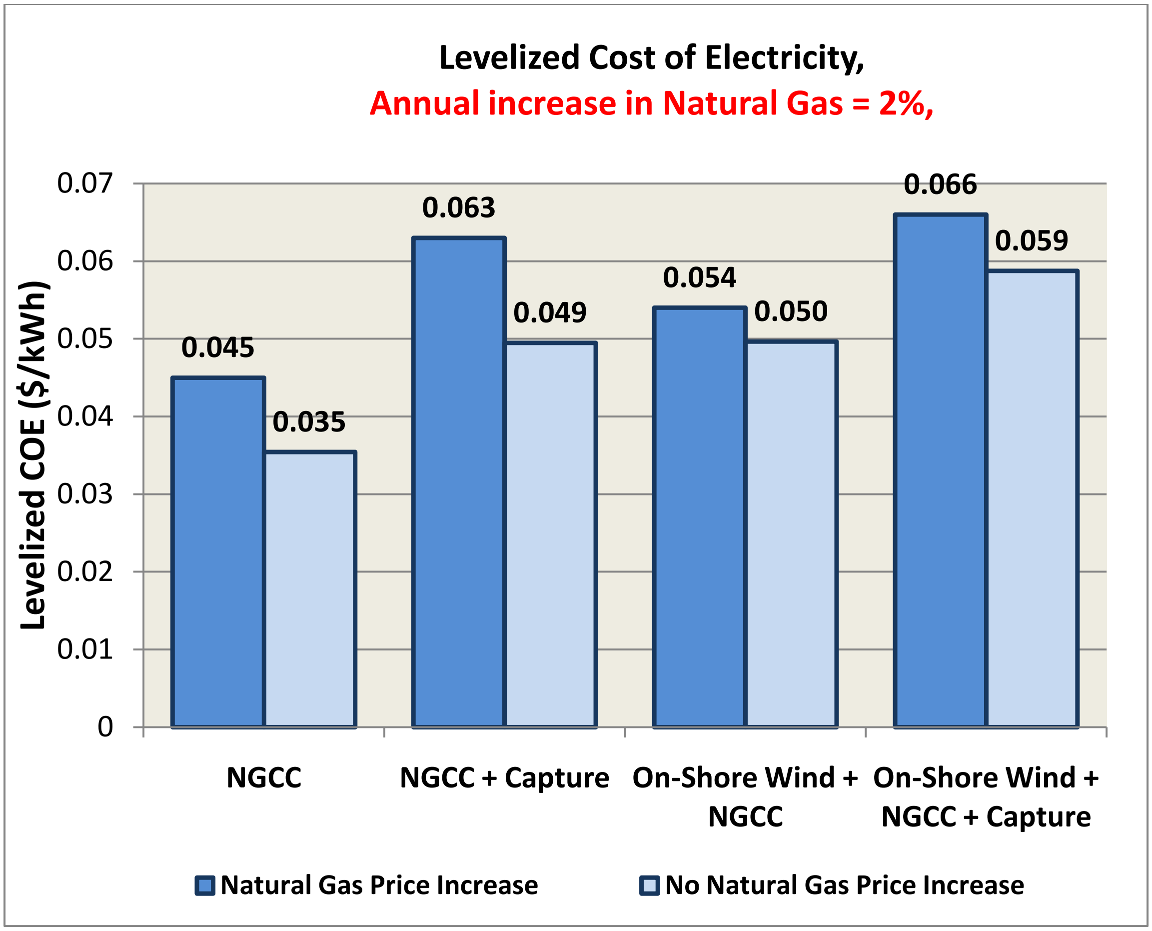
- Fossil fuel and nuclear lifetime: 50 years
- Solar lifetime: 30 years
- Wind lifetime: 20 years
- Discount rate: 5%
- Price of Coal=$1.55/MMBtu
- Price of Natural Gas=$4.50/MMBtu
- Price of Uranium=$0.67/MMBtu





Levelized Cost of Electricity ($/kWh)
0.140
0.120
0.100
0.080
0.060
0.040
0.020
0.000
Levelized COE, $/kWh
0
25
50
100
Cost of Carbon ($/tonne CO2)
IGCC
IGCC + Capture
NGCC
NGCC + Capture
Subritical
Subcritical + Capture
Supercritical
Supercritical + Capture
Oxyfuel Super
Oxyfuel Ultra
Nuclear
On-Shore Wind + NGCC
On-Shore Wind + NGCC + Capture


Levelized Cost of Electricity Among Select Alternative Power Generation Options ($/kWh)
Levelized COE ($/kWh)
0.200
0.180
0.160
0.140
0.120
0.100
0.080
0.060
0.040
0.020
0.000
0
25
50
100
Cost of Carbon ($/tonne CO2)
Nuclear
On-Shore Wind
On-Shore Wind + NGCC
On-Shore Wind + NGCC + Capture
Off-Shore Wind
Solar PV
Solar Thermal


Levelized Cost of Electricity,
Annual increase in Natural Gas = 2%,
Levelized COE ($/kWh)
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0
0.045
0.035
0.063
0.049
0.054
0.050
0.066
0.059
NGCC
NGCC + Capture
On-Shore Wind + NGCC
On-Shore Wind + NGCC + Capture
Natural Gas Price Increase
No Natural Gas Price Increase

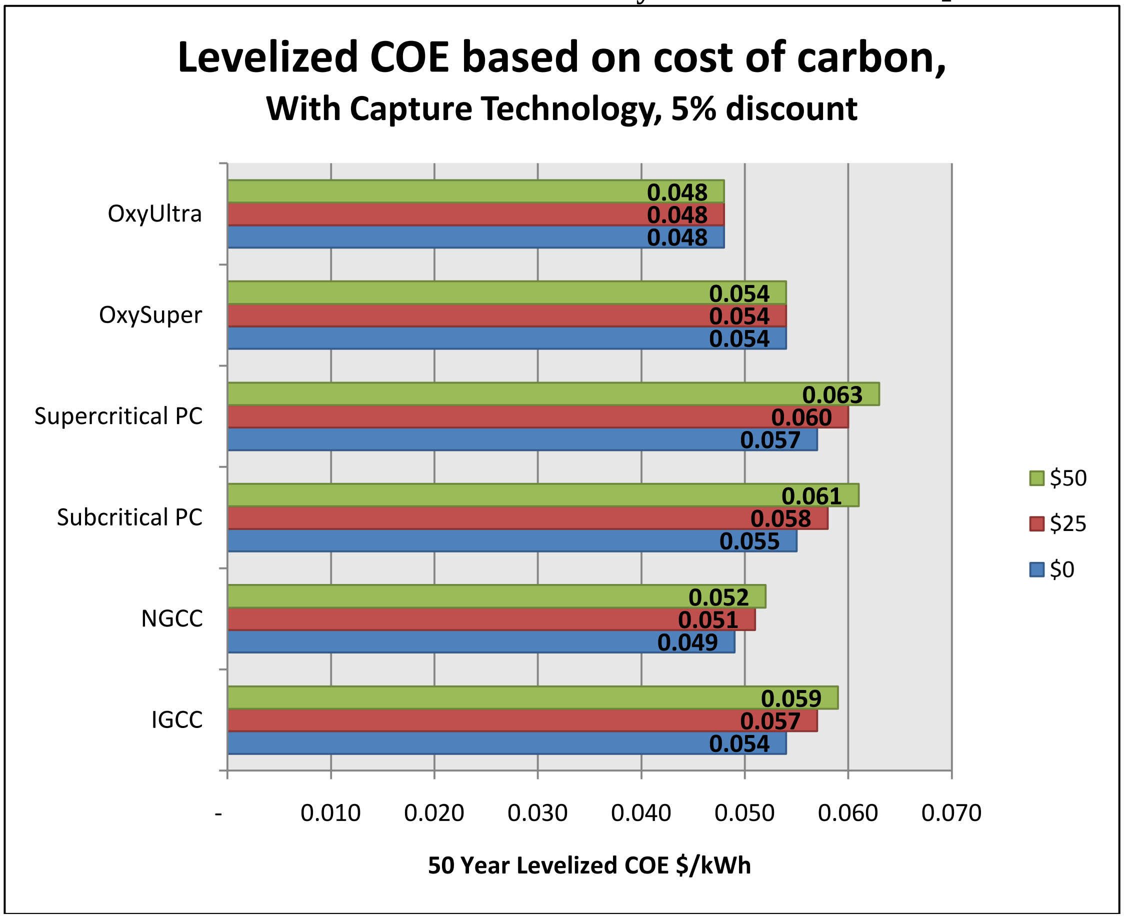
Meeting Proposed California GHG Emissions

		IGCC		
	Report Case Number →	1	2	3
	CO_2 Capture Level	None	54%	90%
	Emission Level (lb/MWh_{net})	1,841	1,100	278
Capital ($/kW)	Base Plant	2,068	2,381	2,684
	Air Separation Unit	311	384	441
	Flue Gas Cleanup[a]	216	406	552
	CO_2 Compression	N/A	55	95
	Power Plant Capital ($/kW)	2,595	3,227	3,772
	Incremental Capital ($/kWh)	N/A	632	1,177
	Total Plant COE (¢/kWh)	8.60	10.60	12.39
	Total COE (Including TS&M) (¢/kWh)	8.60	11.11	13.06
	Incremental COE (¢/kWh)[b]	-	2.51	4.46
	Increase in COE (%)[b]	-	29	52
	$/ton CO_2 Avoided	-	64	55

[a]Includes: Sulfur, Hg, PM, CO_2 removal, WGS reactors; [b]Compared to Case 1—Greenfield IGCC w/o CO_2 capture

Ciferno, 2008

Levelized Cost of Electricity based on Cost of CO_2



*Sources: NETL 2007; DOE - module, 2010; Logan and Kaplan, 2008; EIA - module, 2010