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CARBON CAPTURE & STORAGE: TECHNOLOGICAL AND REGULATORY CONSIDERATIONS

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1. Introduction

Concerns about climate change have focused the attention of policy-makers on ways to capture and store carbon dioxide emissions from fossil-fueled electricity generators. This has highlighted the importance for regulators to understand the issues at play with carbon capture and storage (CCS). Efforts are underway to develop capture technologies, geologic storage opportunities, and the regulatory frameworks that will affect CO_2 transport and storage. This paper summarizes the high-level technological and policy considerations for CCS, including:

- Differences between capture technologies from a mechanical and chemical perspective;
- Research projects that are underway at various institutions;
- Geological and financial aspects of storage options;
- An overview of current storage siting policies, and unanswered economic and jurisdictional questions;
- Questions of financial, environmental, and health and liability risks as well as mitigating factors and practices; *and*
- Pipeline planning, permitting, and safety concerns.

This document is meant to be a broad overview of CCS technology and regulation. This document, and its companion primer, "*Primer for State Regulators: Coal Generation Technologies for New Power Plants*" explore the basic questions regarding generation, carbon capture and storage to help Public Utility Commissions understand both the existing body of knowledge surrounding technologies and governing policies as well as some of the remaining questions.

2. Capture Ready vs. Capture Capable

The next generation of coal plants may look and function differently from traditional plants. Regulators may be faced with complex technology decisions regarding carbon capture-capable and carbon capture-ready designs, and understanding the difference may be critically important.. Simply stated, capture-capable means that a generation plant has the technology to prevent atmospheric emissions of carbon dioxide. Capture-ready means that the plant does not have the carbon capture technology installed during construction, but is designed to make the addition of such technology possible in the future with minimal impact on the lifetime economic performance. During the plant specification stage, a design study is conducted to evaluate the feasibility and cost-effectiveness of additional pre-investment options for adding carbon dioxide capture. The distinctions between the terms is important to understand, but it should be noted that this distinction was not highlighted in much of the literature reviewed for this primer.

3. Capture Technologies

Approaches for capturing carbon from the emission streams of power plants fall into two broad categories, mechanical processes and chemical processes, discussed in this section.

A. Mechanical Processes

Those designing, constructing, or regulating capture-capable or capture-ready plants may face choices about the benefits and constraints of the various capture technologies. Different technologies can affect the plant's capacity and efficiency as well as the price of electricity. This paper focuses on three methods of carbon capture: post-combustion, oxygen-combustion, and pre-combustion capture.

Post-combustion capture utilizes solvents to remove CO_2 from a plant's flue gas. The most common technology uses a chemical amine solution to absorb the CO_2. This substance is then heated, releasing the CO_2 for capture.

While CO_2 is effectively removed, there may be trade-offs with this technology. For example, the overall efficiency and net capacity of the plant may be lowered due to the high power and steam requirements of the process. Some analyses suggest that these capacity and efficiency losses are in the range of 25-30% relative to the same combustion without CO_2 capture. These analyses also suggest that due to large amounts of flue gases to be processed, the equipment could be very large, affecting the design requirements for power plants designed to leave available space for the future addition of these technologies.

There are a number of promising technologies under development that will be applicable to new and existing facilities. They include advancements to amine solvents as well as alternative solvents including a chilled ammonia process. The latter has been deployed at a pilot facility by Wisconsin Energy in partnership with EPRI and technology developer Alstom, with scaled-up demonstration planned at two American Electric Power facilities. EPRI studies indicate that the problems such as capacity and efficiency losses and reagent degradation commonly found in post-combustion capture solutions can be substantially reduced using the chilled ammonia process. Developments in post-combustion capture technologies may have the potential to reduce the cost of CO_2 capture from pulverized coal and fluidized bed plants. More common chemical capture processes will be discussed in the next section.

Oxygen-combustion, also known as oxyfuel-combustion is a second capture technology. In this process, pulverized coal is burned in high purity oxygen rather than air. Burning the fuel in this manner results in water and CO_2 – substances that are technologically separable. The high concentrations of CO_2 are suited for direct capture.

This option is most often considered for existing coal boilers without any SO_2 and NOx control in the hope that these pollutants can be captured and disposed of with the CO_2. However, disposing of all these pollutants together is difficult due to the physical properties of the gases. As with post-combustion, oxygen-combustion presents trade-offs. The large power requirements for both oxygen production and operation of the CO_2 compressor may lead to drops in net capacity and efficiency in the range of 25-30% relative to the same combustion system without CO_2 capture.

Pre-combustion capture is another method of CO_2 capture. This process involves converting fossil fuel into hydrogen and CO_2, usually by gasification. Therefore, pre-combustion capture is appropriate for IGCC plants. During pre-combustion, coal is transformed into synthesis gas (syngas), which is a mixture of hydrogen and carbon monoxide. The carbon monoxide is converted into CO_2 and, using a solvent, removed prior to combustion. Electricity is generated by combusting hydrogen in a gas turbine with minimal CO_2 emissions. Further efficiencies are gained by using waste heat to power a steam turbine.

Compared to oxyfuel combustion, this process requires much less oxygen per unit of fuel feedstock or net power output. CO_2 can be recovered in a dry condition, at moderate pressure with little or no use of steam. The result is a significant reduction in both the CO_2 compressor capital and power requirements. Net capacity and efficiency losses are reduced. Additionally, the hydrogen produced in this process can be used to generate electricity in a fuel cell, a promising attribute for future generation technologies.

At the present time, none of these technologies have been widely commercialized. A project that was funded by the Department of Energy called "FutureGen" was intended to develop a facility to explore advanced capture technologies on a commercial scale at a coal-fired power plant, however this program has been recently restructured to explore and prove these concepts in other ways. FutureGen and its restructuring will be discussed again in a later section of this overview.

B. Chemical Processes

Just as there are variations in the mechanical process, there are also differences in the way CO_2 is chemically removed from the emissions stream. Below are descriptions of four chemical processes that separate CO_2 from the plant emissions and the benefits and drawbacks of each process.

Absorption (Solvent Scrubbing) uses solvents to absorb CO_2 gases. It is akin to "scrubbing" exhaust gases. This technology has been employed for over 60 years by the oil and chemical industries to remove CO_2 from gas streams. Commercially, it is the most well established of the techniques available for CO_2 capture. One example of a coal-fired power station employing amine scrubbing is the Warrior Run plant in Cumberland, Md. However, this process can be energy intensive, and research suggests this may be more effective if used with a pre-combustion process to reduce energy losses. More research is needed to improve the solvents used for capture thereby lessening the energy requirement.

Adsorption is the process by which a gas fixes to the surface of a solid. Some porous solids with large surface areas are able to adsorb (or attract and hold) large quantities of gas. Fitting the plant with an adsorbent bed can remove CO_2 from power plant flue gases. After the CO_2 has attached to the adsorbent substance it may be released and trapped by altering the pressure or temperature of various parts of the system or washing to adsorbent bed with a gas that releases the CO_2.

Cryogenic Separation involves separating CO_2 from other gases by cooling and condensation. Cryogenics are used widely for separating highly concentrated CO_2 from other gases, making it suitable for pre-combustion capture. However, this process can be easily contaminated and can harm the plant's capture equipment. Also, the behavior of the CO_2 is complicated and may end up interfering with the equipment. A final drawback to this technology is that the process is very energy intensive.

Membrane Separation utilizes gas separation membranes. These membranes allow one component in gas stream to pass through faster than others. The efficacy of a membrane depends upon its permeability (the rate of the flow of the gas through the membrane) and selectivity (the ability for one component of the gas to permeate faster than others). For CCS purposes, a permeable membrane that is highly selective with respect to CO_2 is desirable.

Still, membranes may not achieve a high degree of separation so the process must be carried out in multiple stages or repeated. Such repetition results in high costs and increased energy consumption. Significant development of the process may be needed before it can be used for capture at a commercial scale on power plants.

The processes discussed are by no means the only methods for separating CO_2 from the flue gas. Researchers are exploring many biological, chemical, and physical separation mechanisms including, but not limited to, the following:

1. CO_2 Mineralization
2. Metal Oxide Air Separation
3. Clathrate Hydrates
4. Chemical Looping
5. Algae Beds

However, these five processes are mentioned with much less frequency in the research than the ones described above. Descriptions of three of these additional methods of CO_2 capture can be found in a report from Stanford University titled, "An Assessment of Carbon Capture Technology and Research Opportunities.[1]"

4. Geologic Storage Options

If the policy goal is to prevent carbon dioxide from being released into the atmosphere, after the carbon dioxide is captured, appropriate storage facilities will need to be found. Again, there are multiple options. Three potential storage sites are presented in this primer: depleted oil and gas fields and enhanced oil recovery (EOR), deep saline formations (saline reservoirs), and unminable coal seams. Other promising site types may exist onshore or offshore, but in every case CO_2 is injected into rock formation below the earth's surface.

Depleted Oil and Gas Fields and EOR are attractive options for CO_2 storage for a number of reasons. First, they held gases and liquids for millions of years before the humans extracted them signifying their capacity to store similar substances. Second, at the depths and temperatures of these fields supercritical CO_2 acts like a fluid. This means that where some recoverable oil or gas resource remains in the reservoir, CO_2 may be useful for filling the reservoirs for enhanced recovery of these resources. Where resources remain in economically depleted reservoirs, using CO_2 to engage in enhanced recovery of these resources creates a revenue stream that can improve the economics of undertaking CO_2 storage. Third, the geology of these formations is known as they have been mapped and studied through previous oil and gas extraction endeavors. Scientists have a solid understanding of the available storage capacity of these fields.

In an oil field, actual CO_2 storage is accomplished in two parts. First, some injected CO_2 is stored in the immobile oil remaining in the reservoir. The rest of the CO_2 is collected from the production well and re-used for EOR. If EOR is employed, it should be noted that there are special operational and monitoring considerations as compared to only storing CO_2 in a depleted field. As mentioned above, and especially for the fields approaching the end of their useful working life, the extra income generated from EOR could offset the cost of CO_2 injection. The Weyburn field in Canada is an example of CO_2 injection for EOR. In this project, 1.8 million tonnes of CO_2 per year will be captured from a coal gasification plant and injected into an oil field. However, implementation of CO_2 capture and storage at the scale of current U.S. emissions from power plants will outstrip EOR opportunities eventually, and may exceed the volume of known petroleum reservoirs in the U.S. in the next 50 to 100 years.

In a depleted gas field the injected CO_2 fills the space previously occupied by natural gas. Research is underway to see if CO_2 can be used for enhanced gas production – a process mimicking EOR. Because of the economic yields, depleted fields and EOR are likely the most economically attractive options for storage in the short-term, but cannot be the only storage option due to the ratio of emissions to storage space.

Deep saline formations, or deep saltwater reservoirs, are rocks with porous spaces that are filled with very salty water. They exist nearly world-wide and have great potential for CO_2 storage. The most suitable reservoirs are those at depths greater than 800m as the CO_2 will behave more like a liquid than a gas, enabling much more to be stored. Carbon dioxide may remain buoyant for hundreds, if not thousands of years until it slowly dissolves in the saline water, eventually sinking deeper into the reservoir. While in the supercritical state the buoyant forces push the CO_2 upwards. A well sealed cap-rock over the storage site will be necessary to ensure that the CO_2 remains underground. However, even if the reservoir was not fully sealed, the CO_2 would not return to the surface for hundreds of thousands of years due to the slow flow rate of CO_2 in porous matter.

[1] Available online at http://gcep.stanford.edu/pdfs/assessments/carbon_capture_assessment.pdf.

A commercial project in the North Sea currently injects CO_2 into an offshore deep saline reservoir. This project, at the Sleipner West gas field, has been operating since 1996. Approximately one million tons of carbon dioxide are injected underground for storage annually. Another project in Alberta, Canada, injects CO_2 into an onshore saline reservoir and has been in operation since 1994.

The geology of deep saline formations is not as well characterized compared to that of oil and gas fields. However, saline reservoirs have been used as buffer stores for natural gas, which supports the belief that CO_2 could be stored safely in carefully selected sites. More research will be needed for these reservoirs to become viable options.

Unminable Coal Seams are a third storage option. The logic behind using these coal seams for storage is similar to that of using depleted oil fields for EOR. These coal beds contain large amounts of methane gas that, if released, can be captured and used for power generation or heating. The idea is that by injecting CO_2 into the coal seam, the methane contained in the surface pores of the coal is displaced and released. This process is known as CO_2-enhanced coal bed methane (CO_2-ECBM) production. Laboratory measurements suggest that twice as much CO_2 can be stored as methane was desorbed. However, since methane is also a greenhouse gas, all of the methane that is released must be captured and put to use for a greenhouse gas emissions benefit to occur. The revenue created by the capture methane can help off-set CO_2 injection costs. However, ECBM is still in the early stages of research and compared to storage in other reservoir types, coal seams appear to have a lesser capacity for storing CO_2.

A CO_2-ECBM pilot project developed by Burlington Resources and BP is underway in the San Juan Basin in the southwestern United States. The project has achieved increased methane production. So far, no CO_2 has been found in the capture methane gas indicating that CO_2 is being stored in the coal seam. Lessons learned from this experiment will be looked to for future consideration of these coal seams as a storage option.

The IEA's Greenhouse Gas R&D Programme and the Intergovernmental Panel on Climate Change have explored the potential of the three primary storage options discussed in this paper, illustrated in Figure 1, below:

Figure 1: Potential Capacity of Geologic Storage Options

Geological Storage Option	**Global Capacity**	
	Gtonne CO_2	**As a proportion of total emission 2000 to 2050**
Depleted Oil and Gas Fields	920[2]	45%
Unminable Coal Seams	>15[3]	>1%
Deep Saline Reservoirs	400 – 10,000	20 – 500%

The storage options presented above are not the only geologic formations under consideration. Other possible storage sites include basalt formations, organic rich shales, salt caverns, and abandoned mines. These options may not be suited for large scale CO_2 storage and/or require extensive additional research to assess their viability as storage sites.

[2] This is the upper limit. The lower limit is 675 $GtCO_2$.
[3] This is the lower limit. The upper limit is 200 $GtCO_2$.

Site selection of storage reservoirs must take many factors into consideration. Various properties of the storage rock and seals, or “traps,” must be considered including:

- Porosity - the measure of the space available for storing the CO_2 (acting as a fluid)
- Permeability - the measure of the ability of the rock to allow fluid to flow; and
- Injectivity - the rate at which the CO_2 can be injected into the site

Generally, a suitable storage site will be highly porous, have a high degree of permeability, and CO_2 will be able to be injected at nearly the same rate as it is captured from the sources. The seal over the storage site, however, should have low porosity and permeability in order to trap the fluids below. The primary sealant is cap rock, a dense layer of impermeable rock located on top of the rocks holding the CO_2. Over time, additional natural trapping processes become active. This means that, usually, the longer the CO_2 stays underground, the more secure its storage becomes. This concept and additional trapping mechanisms are explained in the January 2008 publication of the International Energy Agency (IEA), *Geologic Storage of Carbon Dioxide – Staying Safely Underground* found at http://cslforum.org/documents/geostoragesafe.pdf. According to this report, a good storage site has the following characteristics:

What is a Good Geologic Storage Site?

Accessibility

- ✓ The location is economically accessible to the source of CO_2.
- ✓ The organization conducting storage has all the legal rights to do so on that site.

Capacity

- ✓ Storage formation has adequate porosity and permeability to store CO_2.
- ✓ The storage formation has adequate total storage volume to serve the intended sources.

Injectivity

- ✓ The formation can store CO_2 at the rate required to serve the intended sources.

Storage Security

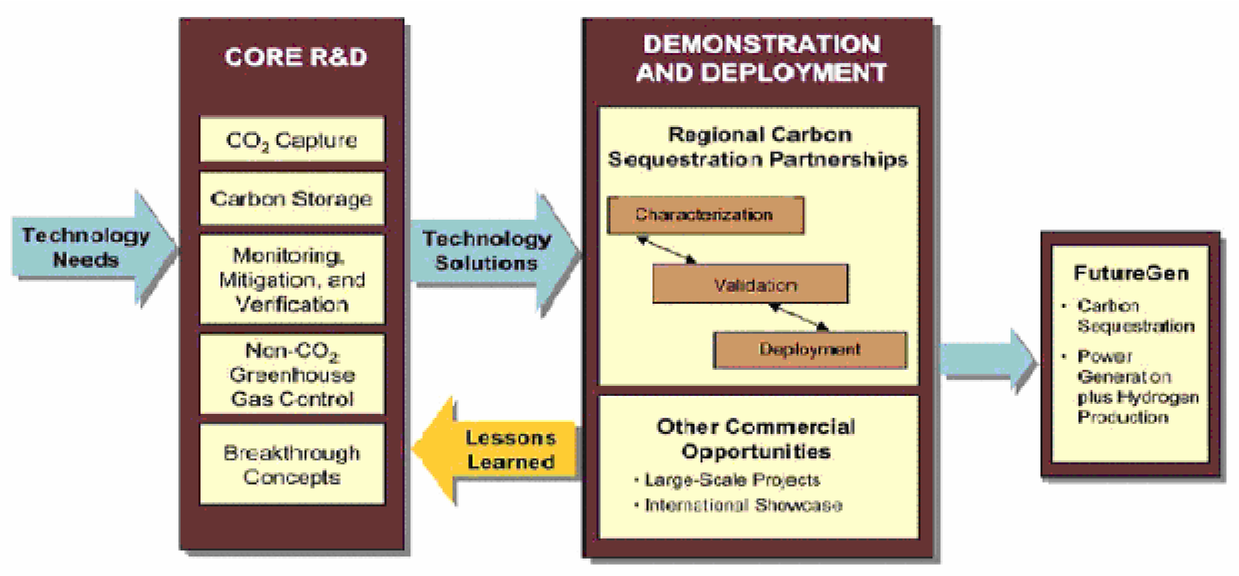
- ✓ Well-defined trapping mechanisms exist within the storage formation.
- ✓ The CO_2 will be stored deep enough to be supercritical.
- ✓ Cap rock is adequately impermeable, continuous and thick to prevent upward migration.
- ✓ The geologic environment is adequately stable to ensure the integrity of the storage site.
- ✓ No pathway faults or uncapped wells penetrate the cap rock and storage formation.

(IEA, *Geologic Storage of Carbon Dioxide – Staying Safely Undergound. January 2008. http://cslforum.org/documents/geostoragesafe.pdf*)

5. Research Underway

Across the world government, academic, industry, and non-governmental research groups are actively researching CCS technologies. The lead government agency in the United States is the U.S. Department of Energy (DOE). The DOE funds and conducts CCS research from exploring potential geologic sites for storage to developing monitoring and verification techniques. The overall structure of their research illustrated the following figure:

Figure 2: The U.S. DOE Research Structure for
Clean Coal Technology & Carbon Capture & Storage

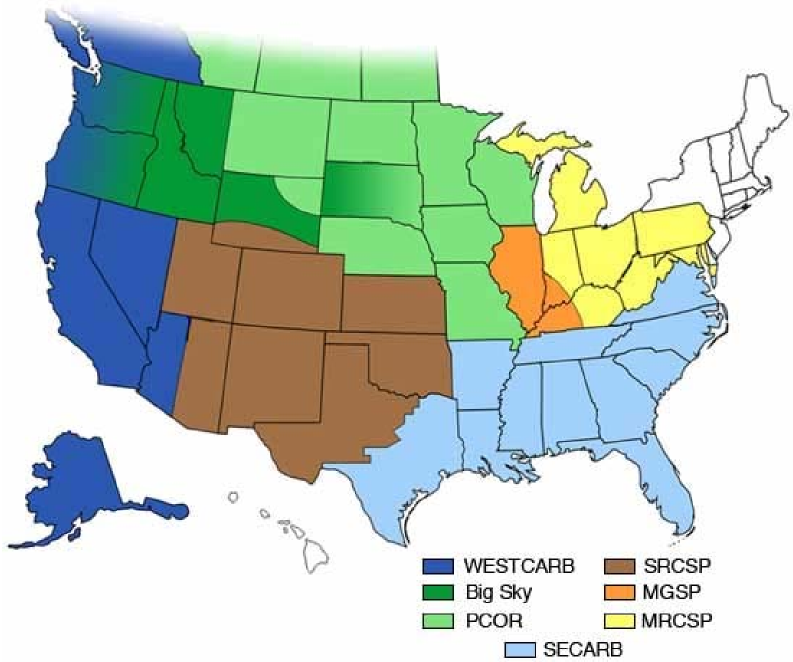


(DOE 2007, "*Carbon Sequestration Technology Roadmap and Program Plan 2007*")

Two noteworthy components of the DOE's research program are the FutureGen initiative and the Regional Carbon Sequestration Partnerships. FutureGen was originally designed in 2003 as a $1 billion initiative to create and operate the world's first zero-emissions fossil fuel plant. The project was initially intended to: prove the effectiveness, safety and permanence of large scale CO_2 sequestration through validating the technology under real world conditions, establish technology standards and protocols for CO_2 measuring, mitigation and verification, and drive other projects to commercialization by 2020. However, in January 2008 the FutureGen project was restructured by the Department of Energy. FutureGen funds will now be used to demonstrate CCS technology at multiple commercial-scale coal-fired Integrated Gasification Combined Cycle power plants. The DOE believes that this new approach will take advantage of technological developments made of the last 5 years and is expected to, at a minimum, double the amount of CO_2 sequestered as compared to the original proposal in 2003. More information on the current status of the FutureGen project can be found at http://www.fossil.energy.gov/programs/powersystems/futuregen/.

Another CCS initiative of the DOE's is the Carbon Sequestration Regional Partnerships. Seven regional partnerships comprised of the DOE, universities, and private companies have been created to examine technologies, policies, and infrastructure necessary for large-scale carbon capture, storage, and sequestration. The formation of these regional partnerships is a recognition of the different challenges and opportunities that exist for sequestration in varying geographic locations. The partnership programs are conducted in three phases, concluding with large scale demonstration CCS technologies. Additional information on the sequestration partnerships is located on http://www.fossil.energy.gov/programs/sequestration/partnerships/index.html.

Figure 3: Regional Carbon Sequestration Projects



(Regional Carbon Sequestration Projects. NatCarb, 2007. http://www.natcarb.org/Atlas/partners.html)

There are many other groups contributing to the mounting CCS research including academic institutions. The Massachusetts Institute for Technology has produced numerous research papers and reports in the last 5 years focusing on the political, legal, societal, technological, and economic factors of CCS. Reports can be found at http://sequestration.mit.edu/bibliography/index.html.

Another group deeply involved in CCS research is the Electric Power Research Institute. They are pursuing research, technology development, and demonstration activities in collaboration with industry, government agencies and laboratories, universities, and non-governmental organizations. One CCS project, a 5-MW demonstration of a post-combustion capture system with reduced energy losses and lower electricity cost impacts began operation in March 2008 in Wisconsin. More information can be found at http://my.epri.com/portal/server.pt?space=CommunityPage&cached=true&parentname=CommunityPage&parentid=9&control=SetCommunity&CommunityID=260&PageID=525.

On an international scale, the International Energy Agency (IEA) is also devoting significant resources to CCS research. The IEA is a group that serves as an energy advisor to 26 member countries including the United States, Australia, Canada, Germany, and Japan. The IEA's work focuses on energy security, economic development and environmental protection. In 1991, the IEA developed the IEA Greenhouse Gas R&D Programme (IEA GHG). IEA GHG supports international research collaboration to assess GHG reduction technologies. More information on the IEA's Greenhouse Gas R&D Programme can be found at http://www.ieagreen.org.uk/.

6. Siting and Permitting

The Safe Drinking Water Act currently regulates CO_2 injection and may provide a model for long-term storage, but a tailored regulatory structure for large-scale, long-term carbon dioxide storage does not yet exist. While some believe the current regulatory models are sufficient, questions remain as to who will regulate long-term storage, the timeframes for how long responsibility for storage lies with each party, and the economics of carbon dioxide storage. These questions are a driving force behind much research.

Such uncertainties translate into higher financial risk and complex liability problems, which will be discussed in the next section.

The EPA and States permit wells used in enhanced oil recovery and experimental CO_2 injection wells under Safe Drinking Water Act (SDWA) authority. Underground injection of CO_2, as directed by the SDWA, is managed through the EPA's Underground Injection and Control (UIC) program, a program regulating underground injection of both fluids considered to be commodities and those deemed waste products.

In March 2007, the EPA finalized UIC Program Guidance #83 *Using the Class V Experimental Technology Well Classification for Pilot Geologic Sequestration Projects*. This document will assist State and EPA regional UIC programs in processing permit applications for experimental projects designed to assess the efficacy of CO_2 injection for the purpose of geologic sequestration. CO_2 behavior underground will be studied as will well construction and operations. The information from these projects will help regulators determine if new UIC regulations for commercial-scale CO_2 injection projects are needed. UIC Program Guidance #83 can be found at http://www.epa.gov/OGWDW/uic/wells_sequestration.html.

Under the UIC program there are five classes of wells.

- Class I is for deep injection of hazardous and non-hazardous industrial wastes.
- Class II permits are issues for wells associated with energy production (EOR).
- Class III is for mineral extraction.
- Class V is for everything else.[4]

As noted above, the EPA has classified experimental wells for geologic sequestration as Class V wells. It should be noted, however, that some groups are pushing for more stringent regulations generally associated with Class I or II wells. However, costs are not determined by well classification, but rather by the associated stringency of the regulations to the particular well. For example, a Class V well with strict and extensive regulatory requirements can be more costly than a Class II well. The EPA is currently developing regulations for commercial-scale geologic sequestration projects. The agency expects to propose regulations in the summer of 2008. The EPA's Underground Injection Control Program's website contains a number of resources for stakeholders involved with geologic sequestration of CO_2 including regulatory guidance and compliance documents as well as a schedule of technical workshops. More information can be found at http://www.epa.gov/safewater/uic/wells_sequestration.html.

Other federal laws which may affect CO_2 storage include, but are not limited to the Resource Conservation and Recovery Act (RCRA) the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), and the Toxic Substances Control Act. States may impose additional siting and permitting requirements for carbon dioxide storage beyond federal requirements. Several states have reported to be moving forward on such work including New Mexico, California, and Washington.

State and the federal governments will need to take many legal, physical, and safety considerations into account when determining an appropriate regulatory framework for CO_2 storage.

- How should multiple users of the same or overlapping underground storage facilities be licensed?
- How should trans-boundary migration of stored CO_2 be managed?
- How should the rights and interests of surface owners be protected?

[4] Class IV designations are no longer given.

These unknowns will need to be answered as decision-makers create a comprehensive regulatory CO_2 siting and permitting regime.

7. Risk And Liability

In addition to the question of who will regulate CO_2 storage, there is the question of who is liable for storage facilities. MIT outlines three major sources of liability:

- Liability from operational impacts;
- Liability from *in situ* risks; and
- Liability associated with deviations from the goal of permanent storage.

The MIT report purports that operational liability can be managed in the same manner CO_2 transportation, injection, and storage is currently handled in the oil and gas production industry. Challenges to this suggestion are discussed in the next section. *In situ* risks include leaks to the surface, migration of carbon dioxide within the storage formation, hydrocarbon resource damage, groundwater contamination, and seismic and other geological events. These risks could have public health, environmental, and/or ecosystem impacts. There are questions surrounding the management of CO_2 leaks and how the escaped carbon dioxide will be accounted for in future carbon regimes. Lastly, there are questions about site closure and long-term stewardship of the closed site.

To gain an understanding of potential future CO_2 storage regulation, the MIT researchers analyzed a number of current regulatory structures that may be important in understanding future regulatory regimes, illustrated in Figure 5, below:

Figure 5: Regulatory Analogs For Carbon Storage Regulation

Regulatory Analog	Key Issues	Implications for Carbon Sequestration
Natural gas transport and storage	• "Routine activities" (not abnormally dangerous) Common Law Liability	• Carbon sequestration a part of everyday life? • How would common law apply to carbon sequestration?
Radon	• Strict liability • Implied warranties	• CO_2 leakage as a design defect • Liability will lie with the agent representing the storage site or the operator of the site. • Dealing with unknown risks (e.g. abandoned mines)
Low-level radioactive waste storage and disposal	• Interstate agreements	• Placing responsibility with federal government versus state • Liability regimes may discourage storage
Hazardous waste storage and disposal	• Strict liability • Joint and several liability • Retroactive liability	• Who should be held liable for leakage? • Liability may change over time

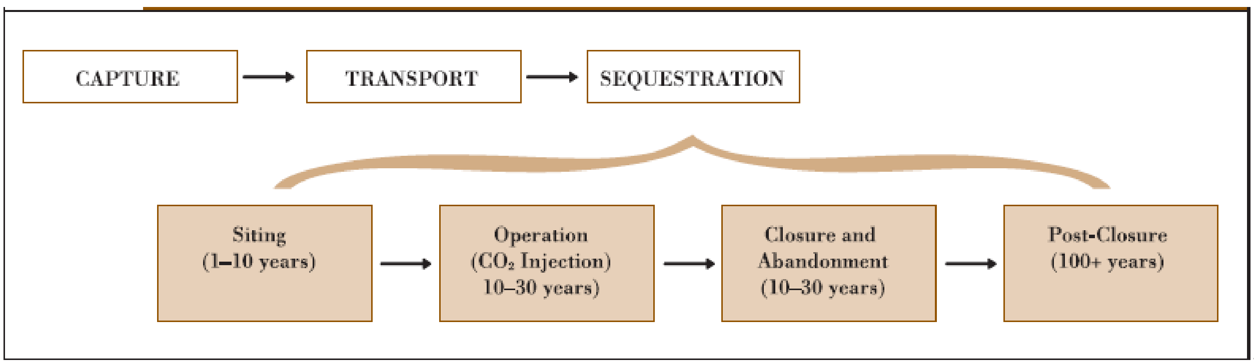
(MIT, "*Towards a Long-term Liability Framework for Geologic Carbon Sequestration*")

Under any liability scheme, CO_2 transport and storage operators may need to address environmental and health risks. Carbon dioxide is an asphyxiant at high concentrations since it is heavier than air. A slow leak from a pipeline or a storage facility is dangerous only if the gas is inadvertently trapped, thereby increasing the concentration. Careful site selection will be required to avoid harmful releases of CO_2 . Pipelines routed through populated areas may require restrictions on levels of hydrogen sulfide, which is also asphyxiating at high concentrations. Route selection and leak detection will be key design components to mitigate the risk of H_2S poisoning. All in all, adverse affects to human health from CCS are not thought to be too great since CO_2 is a significantly less volatile gas than many other gases that are used for energy production. Pipeline safety regulation will be discussed in the next section.

One environmental concern commonly voiced in CCS literature is that of water contamination. Researchers have expressed concern over the potential for CO_2 to migrate underground and interact with groundwater supplies. However, CO_2 storage will occur in formations which are significantly deeper that groundwater supplies and overlain by impermeable formations which prevent CO_2 from migrating upward. In addition, as noted above, permitting requirements under the SDWA are intended to protect drinking water supplies. Acidification of soils and displacement of oxygen in soils are additional environmental concerns, but such hazards may be reduced through careful storage system design, siting, and detection techniques.

With regard to long-term storage issues, a World Resources Institute primer discussing liability and financial responsibility frameworks for CCS outlines the risks for geological carbon storage over the life of a project, included in Figure 4, below:

Figure 4: The Geological Sequestration Project Life Cycle



From the World Resources Institute, *Liability & Financial Responsibility for Carbon Capture & Sequestration*, http://www.wri.org/ccs-publication/liability-financial-responsibility

It is likely that careful monitoring and detection will be the key to the efficacy of long-term storage. The parties responsible for the long-term care of an injection site will likely need to monitor the integrity of the injection well against leakage, detect leakage early for effective remediation, and then monitor the effectiveness of remediation efforts. The IEA, supported by data from the IPCC, reports that with proper site selection, operation, and monitoring 99% or more of the CO2 injected through CCS would remain in the intended storage formation for at least 1000 years.

8. Cost Recovery and Financial Risk

The regulatory uncertainties discussed above create significant financial risks associated with CCS. Technologies like IGCC and supercritical pulverized coal add an extra layer of risk to utility operations. Risks commonly associated with pulverized coal plants include:

- Construction cost escalation
- Delays in construction
- Technology changes during the construction phase
- Relative cost of fuels could change
- Political reactions
- Cost recovery timelines

There are existing risk management and insurance products that can help developers and operators deal with the risks stated above. However, developers considering power plants with CCS have an additional risk to consider: regulatory uncertainty around the structure of a potential future system governing CO_2 emissions. A regulatory regime that extensively restricts emissions, and results in a high price of carbon, may make CCS a more economically attractive option for utilities, while a low price will make allowances or other strategies more compelling. Changes in the marketplace for electricity (potentially partly driven by regulatory policy) may also make alternatives to coal-fired generation more or less competitive. The unknowns created by the potential of this regulatory regime

All of these financial and operating risks are exacerbated by new CCS technologies and the uncertainties that accompany them including:

- Higher cost per KW of investment
- Long Construction Time (exacerbates other risks)
- Uncertainty of Long Term Performance

Business-as-usual approaches may also pose risk. While it is a less risky option for utilities, the effects of climate change have the potential to affect national security, business practices, and public health. Conservative funding strategies are one option for utilities to lessen financial risk for themselves. Additionally, regulators may want to consider ensuring pre-approval of cost recovery including constructions costs. Such action can lead to a lower overall cost of capital and less rate shock when the construction is completed.

However, lower overall cost of capital is relative. Some experts caution that everyone should be prepared for capital expenditure costs to rise. Rising costs for infrastructure parts among other expenditures will lead to rising marginal costs.

9. Permitting CO_2 Pipelines

Over 2,500 km of CO_2 pipeline already exist in the United States and have been in operation since the early 1970s. Most of the pipelines transport CO_2 to EOR sites in Texas. This network of CO_2 pipelines may expand as CO_2 storage facilities begin operation around the country. Exactly how much the pipeline network will expand is unknown. It is possible that nearly 75% of the total annual CO_2 captured from the major North American sources may be stored in reservoirs beneath the source of emissions, for example the MIT study concluded that most coal-fired power plants are located in regions where there are likely sequestration sties in close proximity. However, other studies seem to indicate unequal distribution of economically and technically feasible storage sites. Regardless of where the pipelines will be, the network of CO_2 pipelines will likely expand and the questions of who and how these pipelines will be permitted will need to be answered.

Currently, interstate CO_2 pipelines fall under the jurisdiction of the U.S. Surface Transportation Board (the Board), which is an independent federal agency affiliated with the Department of Transportation. The Board regulates *commodities* other than water, oil, or natural gas. However, if there are dramatic increases in the volumes of captured CO_2 being transported and stored, this regulatory scheme may be called into question.

Some of the more prominent questions pertain to common carrier issues resulting from the increased number of interstate interconnections and users expected of the larger pipeline network. Regulators may be faced with the following questions :

- When setting rates, should there be separate rates for existing pipelines carrying CO_2 as a commodity versus new pipelines carrying CO_2 as a waste?

- Will State condemnation laws used to secure sites for infrastructure deemed to be in the public interest allow for CO_2 pipelines to be treated as public utilities or common carriers?
- On federal lands managed by the Bureau of Land Management, will new CO_2 pipelines be sited under the provisions of the Mineral Leasing Act (has common carrier requirements) or the Federal Land Policy management Act (does not have such requirements)?

The issues of costs and cost recovery for CO_2 pipelines may also challenge the claim that sufficient pipelines regulations are already established in the United States. Costs of CO_2 transport are largely determined by the distance and quantity transported, whether the pipeline is onshore or offshore, the terrain, and the degree of congestion around the pipeline route. An additional cost is the material of the pipe itself. Steel is a signification portion of the cost of a pipeline. The fact that the price of steel doubled between 2003 and 2005 illustrates the point that fluctuations in materials costs can have a large affect on pipeline economics.

Differences in cost recovery methods depend upon whether the pipeline is owned and utilized for a single plant or is owned by a third party and part of a larger system. In both cases, costs may be recovered in rates. However, in the former scenario the pipeline could be considered an extension of the plant while the pipeline may be considered an operating cost under the latter case.

Additional cost concerns exist at the federal level. Creating targeted tax benefits for pipelines when some CO_2 is considered a commodity and the rest is categorized as waste will be a challenge. Details of cost recovery and incentive designs are concerns that will need to be resolved to lessen the financial risks perceived by utilities and pipeline operators.

An expansion of the pipeline network may also bring out issues that are similar to those seen in developing regional transmission networks. Variations in State economic regulation of CO_2 pipelines may lessen the level of attraction of CO_2 pipelines for capital investment. As the network develops from a series of intrastate pipelines to a network of interstate pipelines, the different economic regulation of CO_2 as a commodity or as a waste across State lines may create complexities for pipeline operators. Operators may repeatedly have to negotiate or litigate siting, pipelines access, and rate “pancaking” issues. Coordinated efforts to create coherent economic CO_2 regulation on at least a regional basis will likely be crucial to the development of an expanded CO_2 pipeline network.

One final consideration of CO_2 pipeline operations is the potential health impact in the event of a leak. The health concern again focuses on CO_2 and other substances that act as asphyxiants. To mitigate health risks, the Department of Transportation regulates interstate CO_2 pipeline safety through the Pipelines and Hazardous Materials Safety Administration (PHMSA). The agency applies nearly the same safety requirements to CO_2 pipelines as it does to pipelines carrying liquids such as crude oil and gasoline. Analysts have shown that mile-for-mile, CO_2 pipelines appear to be safer than the other types of pipelines regulated by the Department. However, others argue that safety and health concerns remain unanswered. They claim that consequence modeling for handling supercritical CO_2 is not fully developed and therefore cannot be adequately addressed during the permitting process. Public acceptance of an expanded CO_2 pipeline network will likely require resolution of these safety and health concerns.

10. Conclusion

Commissions are increasingly aware that the deployment of a new generation of coal plants with carbon capture abilities may require careful analysis and implementation of capture technologies, transport infrastructure, and storage capabilities. At every step of the way, regulators will need to consider planning, economic, environmental, and health impacts of CCS.

Any assessment of the current state of CCS technology will vary depending upon what portion of the process is in question and whom you ask. Capture technologies are largely known, but not commercialized. Portions of CCS regulatory policies are still in developmental stages, although some will argue that there are appropriate models upon which to base these regulations. Government, academia, industry, and non-governmental groups are all investing in research to advance CCS technologies and policies. Time, political will, and intellectual and capital investment are driving these efforts to move CCS from an experimental/exploratory phase to practical implementation.

Resources Used For This Primer

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