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Scaling up carbon dioxide capture and storage: From megatons to gigatons

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ABSTRACT

Carbon dioxide (CO_2) capture and storage (CCS) is the only technology that can reduce CO_2 emissions substantially while allowing fossil fuels to meet the world's pressing energy needs. Even though the technological components of CCS—separation of CO_2 from emissions, transport, and secure storage—are all in use somewhere in the economy, they do not currently function together in the manner required for large-scale CO_2 reduction. The challenge for CCS to be considered commercial is to integrate and scale up these components. Significant challenges remain in growing CCS from the megaton level where it is today to the gigaton level where it needs to be to help mitigate global climate change. These challenges, none of which are showstoppers, include lowering costs, developing needed infrastructure, reducing subsurface uncertainty, and addressing legal and regulatory issues. Progress will require a series of demonstration projects worldwide, an economically viable policy framework, and the evolution of a business model.

1. Introduction

Carbon dioxide (CO_2) capture and storage (CCS) is a process consisting of the separation of CO_2 from the emissions stream from fossil-fuel combustion, transporting it to a storage location, and storing it in a manner that ensures its long-term isolation from the atmosphere (IPCC, 2005). Currently, the major CCS efforts focus on the removal of CO_2 directly from industrial or utility plants and storing it in secure geological reservoirs. The rationale for CCS is to allow the continued use of fossil fuels while reducing the emission of CO_2 into the atmosphere, thereby mitigating global climate change.

At present, fossil fuels are the dominant source of global primary energy supply, and they will likely remain so for the rest of the century. Fossil fuels supply over 85% of all primary commercial energy; the rest is made up of nuclear energy, hydroelectricity, and renewable energy (commercial biomass, geothermal, wind, and solar energy).

Although great efforts and investments are being made by many nations to increase the share of renewable energy in the primary energy supply and to foster conservation and efficiency improvements, addressing climate change concerns during the coming decades will likely require significant contributions from CCS. In his keynote address at the 9th International Conference on Greenhouse Gas Control Technologies (GHGT-9), Jae Edmonds, chief scientist at the Joint Global Change Research Institute, reported that "meeting the low carbon stabilization limits that are being explored in preparation for the IPCC 5th Assessment Report are only possible with CCS" (Edmonds, 2008).

In order for CCS to be considered a major climate change mitigation option, it must be able to contribute CO_2 emissions reductions on the scale of billions of metric tons (gigatons, Gt) per year. Today, its contribution is on the scale of millions of metric tons (megatons, Mt) per year. At present, only four large-scale CCS projects are in operation (Table 1). All of these projects are injecting on the order of 1 Mt CO_2 per year.

This paper describes the status of CCS today and discusses the key issues that must be addressed for CCS to grow from megatons to gigatons. Understanding these issues is critical for modeling CCS technologies and developing scenarios for climate change mitigation. Section 2 describes the major components of a CCS system and their commercial uses today. The next four sections then look at four key issues for scaling up CCS:

- cost
- transportation infrastructure
- subsurface uncertainty
- regulatory and legal issues.

Although some of the examples cited have a U.S. focus, the general conclusions are applicable worldwide. Section 7 looks at the road ahead, identifying specific actions and timetables required for CCS to reach the gigaton scale. Section 8 concludes.

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Table 1
Existing megaton-scale CCS projects.

Project	Leader	Location	CO_2 source	CO_2 sink
Sleipner (1996)	Statoil	North Sea, Norway	Gas processing	Saline formation
Weyburn (2000)	Pan Canadian	Saskatchewan, Canada	Coal gasification	Enhanced oil recovery
In Salah (2004)	BP	Algeria	Gas processing	Gas reservoir
Snohvit (2008)	Statoil	Barents Sea, Norway	Gas processing	Saline formation

2. Components of a CCS system

Although there is no unique way to break down a CCS system into its component parts, typical components include

- *Capture*, or the separation of CO_2 from an effluent stream and its compression into a liquid or supercritical state.[1] In most cases today, the resulting CO_2 concentration exceeds 99%, although lower concentrations may be acceptable.[2] Capture is generally required to be able to economically transport and store the CO_2.
- *Transport*, or the movement of the CO_2 from its source to the storage reservoir. Although transport by truck, train, and ship are all possible, transporting large quantities is most economically achieved with a pipeline.
- *Injection*, or depositing CO_2 into the storage reservoir. Since the main storage reservoirs under consideration today are geological formations, these will be the focus in this paper. Other potential reservoirs include the deep ocean, ocean sediments, and mineralization (conversion of CO_2 to minerals). Although commercial use of CO_2 may be possible, the amount that can be used will be very small compared with power plant emissions.
- *Monitoring*. Once the CO_2 is in the ground, it must be monitored. Since CO_2 is neither toxic nor flammable, it poses only a minimal health and safety risk (Heinrich et al., 2004). The main purpose of monitoring is to make sure that the sequestration operation is effective, meaning that almost all the CO_2 stays out of the atmosphere for thousands of years.

All the necessary components of a CCS system are in commercial use today somewhere in the economy. However, there is no CCS industry today, because the components do not currently function together in the manner required for large-scale CO_2 reduction. The challenge for CCS to be considered commercial is to integrate and scale up these components. Section 2.1 briefly summarizes the current commercial uses of each of the aforementioned components.

2.1. Capture

The idea of separating and capturing CO_2 from the flue gas of power plants did not originate out of concern about climate change.[3] Rather, it gained attention as a possible economic source of CO_2, especially for use in enhanced oil recovery (EOR) operations, where CO_2 is injected into oil reservoirs to increase the mobility of the oil and thus the output of the reservoir. Several commercial CO_2 capture plants were constructed in the late 1970s and early 1980s in the United States. When the price of oil dropped in the mid-1980s, the recovered CO_2 became too expensive for EOR operations, forcing the closure of these capture facilities. However, the North American Chemical Plant in Trona, CA, which uses this process to produce CO_2 for carbonation of brine, started operations in 1978 and is still operating today. Several more CO_2 capture plants have been built subsequently to produce CO_2 for commercial applications and markets. The amount of CO_2 captured ranges from a few hundred tons a day to just over a thousand tons a day. Deployment of capture technologies for climate change purposes will entail very substantial increases in scale, since a single 500-MW coal-fired plant produces about 10,000 metric tons CO_2 per day (Herzog, 1999).

2.2. Transport

There exists over 3400 mi of CO_2 pipelines in the United States. Their main function is to transport CO_2 from naturally occurring reservoirs to the oil fields of West Texas and the Gulf coast for EOR. The Wyoming and Colorado pipelines are fed by the LaBarge natural gas processing plant, where large quantities of CO_2 need to be separated from the natural gas for the latter to meet commercial specifications, such as heating value. The North Dakota pipeline is fed by the Great Plains Synfuels Plant, which produces synthetic natural gas from coal, with large amounts of CO_2 as by-product (Heinrich et al., 2004).

2.3. Injection

Although a relatively new idea in the context of climate change mitigation, injection of CO_2 into geological formations has been practiced for many years (Heinrich et al., 2004):

- *Acid gas injection.* Acid gas injection projects remove hydrogen sulfide and CO_2 from a produced oil or natural gas stream and compress and transport these “acid gases” via pipeline to an injection well, where they are disposed of by injection into geological formations. In 2001 nearly 200 million m^3 of acid gas was injected into formations across Alberta and British Columbia at more than 30 different locations. In most of these projects, CO_2 represents the largest component of the acid gas, up to 90% of the total volume injected for some projects.
- *Enhanced oil recovery.* CO_2 injection into geological formations for EOR is a mature technology, having first been implemented in 1972. In 2000, 84 commercial or research-level CO_2 EOR projects were operational worldwide. The United States, the technology leader, accounts for 72 of the 84 projects, most of which are located in the Permian Basin of Texas. Combined, these projects inject over 30 million metric tons of CO_2 per year. Outside the United States and Canada, CO_2 EOR projects have been implemented in Hungary, Trinidad and Tobago, and Turkey.

Like acid gas injection and EOR, natural gas storage is a commercial activity. Natural gas, like CO_2, is a buoyant fluid when injected into a geological formation, so their behavior is similar. Natural gas was first injected and stored in a partially depleted gas reservoir in 1915. Since then, underground natural gas storage has become a relatively safe and increasingly widespread process used to help meet seasonal as well as short-term peaks in demand. Because depleted oil and gas reservoirs were not readily available in the Midwest, saline aquifers were tested and developed for storage in the 1950s. Between 1955 and 1985, underground storage capacity grew from about 2.1 trillion cubic feet (Tcf) to 8 Tcf. Since CO_2 stored underground will be much denser than natural gas, 8 Tcf of natural gas capacity is roughly

[1] At temperatures above 31.1 °C, a supercritical state occurs when CO_2 is compressed to above its critical pressure of 73.9 bar. At these pressures the properties (e.g., density) of CO_2 are more like those of a liquid than a gas.

[2] Researchers are investigating processes that can capture criteria pollutants (e.g., sulfur dioxide and nitrogen oxides) along with the CO_2. Although this has the potential to reduce capture costs, it may cause concerns or add costs related to storage. At this time there are no definitive answers to questions regarding desired CO_2 purity.

[3] The four projects in Table 1 capture CO_2 from industrial sites, where a fairly pure stream of CO_2 is a process by-product. At a power plant, CO_2 is emitted at low concentrations (5–15%) in the flue gas, requiring a more difficult and costly capture process. Technical details on how capture processes work can be found in MIT (2007) and IPCC (2005).

equivalent to the storage space needed to hold all the CO_2 emitted annually from all the power plants in the United States.

2.4. Monitoring

Many tools and techniques used in oil and gas exploration and production are directly applicable to CO_2 storage (IPCC, 2005). Chief among these are several seismic techniques, including time-lapse 3D seismic monitoring, passive seismic monitoring, and cross-well seismic imaging. There are also many other methods, such as using tracers, sampling the reservoir brines, and soil gas sampling.

3. Costs

In MIT's *The Future of Coal* report (MIT, 2007), detailed cost estimates were developed for CCS. However, these costs were based on analyses done in the 2000–2004 time frame and expressed in 2005 U.S. dollars. Since then, commodity and fuel costs have risen significantly, resulting in significant increases in the cost of CCS. For example, Cambridge Energy Research Associates reports that capital costs for coal-fired power plants have risen about 80% over this time frame.[4]

More recently, the cost estimates from *The Future of Coal* were updated by Hamilton et al. (2009) to account for escalation in capital, operating, and fuel costs (Table 2). These costs are in line with those recently reported by McKinsey and Company (2009) and Al-Juaied and Whitmore (2009). These costs are for an *N*th plant, where *N* is in the range of 5 to 10. The first several CCS plants built will be more expensive, as what typically happens with the introduction of new technologies. It should also be recognized that the market is highly volatile and costs are constantly changing.

The cost updates in Hamilton et al. (2009) are based on capture from supercritical pulverized coal (SCPC) power plants, sufficient information about which existed in the literature to support these new estimates. Estimates for capture from integrated gasification-combined cycle (IGCC) power plants were not included, because any current IGCC cost estimates are highly uncertain. Costs for IGCC may have doubled or tripled since 2004. To present a new estimate under such high uncertainty would be detrimental to the discussion about new generation technology. This situation underscores the importance for new comprehensive design and cost studies reflecting the new technical knowledge about IGCC in this transient cost environment.

In summarizing CCS costs for the SCPC case, two points should be noted:

- The mitigation cost for capture and compression is about $52 per metric ton CO_2. This does not include transport and storage costs, which are very site specific. However, we can estimate a typical range of $5–15 per metric ton CO_2. This implies that a carbon price of about $60–65 per metric ton CO_2 is needed to make these plants economical in the marketplace.
- Adding capture to a power plant raises the cost of electricity by about $0.04 per kWh. This represents an increase in the *delivered* price of electricity in the 25–50% range.

The cost of CCS from nonpower industrial sources may be significantly less than that from coal-fired power plants, and these sources may be good initial targets for CCS demonstration and deployment. However, their cumulative CO_2 emissions are much smaller than those from coal-fired power plants.

Unlike with other major mitigation options (i.e., renewables, nuclear energy, and increased efficiency), the only reason to utilize CCS technologies is to reduce CO_2 emissions. Therefore, climate policies are essential to create a significant market for CCS. In theory, there could be a market for CO_2 capture if one could sell the captured CO_2. In fact, much of the commercial CO_2 used in the United States is a by-product of industrial processes. However, the potential market is on a scale of only megatons. Furthermore, if the CO_2 source is a power plant, it is generally too expensive to sell the CO_2 for EOR or other commercial uses.

Assuming that there will be a climate policy that puts a price on carbon, initially it will probably be insufficient to lead to wide-scale deployment of CCS. Scenarios can be generated that compare this carbon price with the cost of CCS, such as that shown in Fig. 1 (Hamilton, 2009). Before 2020 the figure shows a sharp decrease in CCS costs as first-mover costs are eliminated, resulting in an *N*th plant cost (the kink in the curve) of about $65 per metric ton CO_2. After 2020 CCS costs decline much more gradually as the technology slowly matures. The carbon price meanwhile has an initial value of $25 per metric ton CO_2 in 2015 and an escalation rate of 4% per year. This price path was chosen because it is probably at the upper end of what is politically feasible in the United States. The resulting gap between the

Table 2
Costs for *N*th plant SCPC generation.
Source: Hamilton et al. (2009).

	Units	SCPC
Reference power plant		
Total plant cost	$/kWe	1910
CO_2 emitted	kg/kWh	0.830
Heat rate (HHV)	Btu/kWh	8868
Thermal efficiency (HHV)		38.5%
LCOE		
Capital	$/MWh	38.8
Fuel	$/MWh	15.9
O&M	$/MWh	8.0
Total	$/MWh	62.6
Power plant with CO_2 capture		
Total plant cost	$/kWe	3080
CO_2 emitted at 90% capture rate	kg/kWh	0.109
Heat rate (HHV)	Btu/kWh	11652
Thermal efficiency (HHV)		29.3%
LCOE		
Capital	$/MWh	62.4
Fuel	$/MWh	20.9
O&M	$/MWh	17.0
Total	$/MWh	100.3
$/ton CO_2 avoided		52.2

HHV, higher heating value; LCOE, levelized cost of electricity; O&M, operations and maintenance; SCPC, supercritical pulverized coal. Dollar amounts are in 2007 dollars.

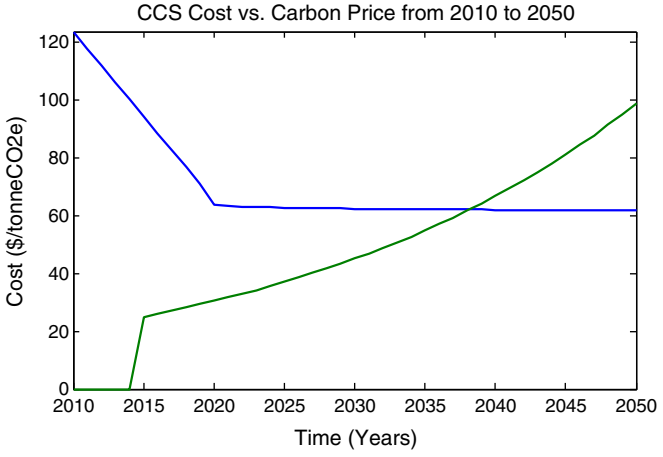

Fig. 1. CCS deployment "price gap." The green line is a carbon price scenario, and the blue line an estimate of CCS costs.

[4] See http://www.ihsindexes.com/.

carbon price and CCS costs will have to be bridged with additional policies. Although one can make many different assumptions about CCS costs, CCS deployment, and carbon prices over time, Hamilton (2009) estimated the cost of such policies to be in the range of $1 billion to $10 billion annually. The two broad categories of policies to bridge this price gap are deployment subsidies (e.g., production credits, investment credits, and loan guarantees) and deployment mandates (e.g., a carbon emission standard).

In addition to bridging the price gap, one can reduce the gap through cost-reducing innovations. The cost curve in Fig. 1 already assumes that economies of scale are achieved and includes some learning by doing. Therefore, the question is whether new technologies will come along that significantly lower the cost curve. The basis for the cost curve in Fig. 1 is a process that consists of cleaning up the flue gas from a pulverized coal power plant (postcombustion capture). This system was primarily designed to deliver low-cost electricity, with CO_2 controls added on. Breakthroughs could be achieved if one were designing a new power plant that minimizes the cost of electricity at the same time that it captures the CO_2. Potential pathways to this goal include precombustion capture in IGCC power plants, oxy-combustion power plants, and chemical looping power plants (see IPCC, 2005, or MIT, 2007, for more details). However, at present, "it is premature to select one coal conversion technology as the preferred route for cost-effective electricity generation combined with CCS" (MIT, 2007).

4. Transportation infrastructure

An infrastructure must be developed to move CO_2 from its source to the storage site. Transporting large quantities of CO_2 is most economically achieved with a pipeline. An important technical consideration in the design of CO_2 pipelines is that the CO_2 should remain above its critical pressure. This can be achieved by recompressing the CO_2 at certain points along the length of the pipeline. Recompression is often needed for pipelines over 150 km (90 mi) in length. However, it may not be needed if a sufficiently large pipe diameter is used. For example, the Weyburn CO_2 pipeline runs for 330 km (205 mi) from North Dakota to Saskatchewan, Canada, without recompression (Hattenbach et al., 1999).

Natural gas pipelines are a good analogue to a CO_2 pipeline network for purposes of understanding costs. A survey of North American pipeline project costs yields several pertinent observations. First, for a given pipeline diameter, the cost of construction per unit distance is generally lower, the longer the pipeline. Second, pipelines built nearer populated areas tend to be more expensive. Finally, road, highway, river, or channel crossings and marshy or rocky terrain also greatly increase the cost (True, 1998).

The cost data for natural gas pipelines consist of cost estimates filed with the United States' Federal Energy Regulatory Commission and reported in the *Oil and Gas Journal* (True, 1990, 1998). Costs are broken down into materials, labor, right-of-way, and miscellaneous components. Materials can include line pipe, pipe coating, cathodic protection, and telecommunications equipment. Right-of-way costs include obtaining the right-of-way and allowing for damages. Miscellaneous costs generally cover surveying, engineering, supervision, contingencies, allowances for funds used during construction, administration and overhead, and regulatory filing fees.

Based on these data, Heddle et al. (2003) estimated costs for CO_2 transport. Fig. 2 shows that economies of scale are reached with CO_2 flow rates in excess of 10 million metric tons per year (equivalent to CO_2 emissions from about 1500 MW_e of coal-fired power). At these flow rates, transport costs are under $1 per metric ton CO_2 per 100 km.

At scale, one can conclude that transport of CO_2 over moderate distances (e.g., 500 km) is both technically and economically feasible.

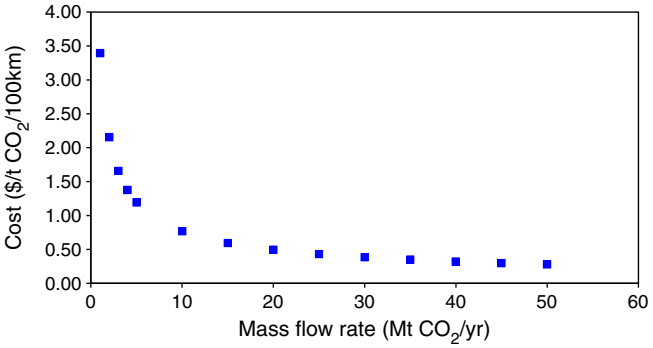

Fig. 2. Cost of CO_2 pipeline transport as a function of CO_2 mass flow rate. Heddle et al. (2003).

The major challenge is building up the transportation infrastructure. Three questions related to this challenge are

- What will the pipeline network look like?
- What comes first, pipelines or capture plants?
- How will the pipelines be regulated?

Currently, there are two regional CO_2 pipeline networks in the United States, one centered in West Texas and the other in Wyoming. Their purpose is to deliver CO_2 for EOR projects. Because CO_2 storage reservoirs are widely distributed, as are coal-fired power plants, one can make the case that future pipeline networks will continue to be regional in nature. The alternative model is that of natural gas pipeline networks, which are national (and even multinational) in nature. At least initially, the regional model is preferred, because regional networks would be more easily implemented and would carry lower total costs than a national network.

Implementing pipeline networks is a classic "chicken and egg" problem. It is not worth building a pipeline network without a critical mass of capture plants to feed CO_2 into the network. However, without the transport infrastructure in place, it is much more difficult to develop CCS projects. Some recent studies (e.g., Chrysostomidis et al., 2009) have looked at the feasibility of developing CO_2 pipeline networks in the North Sea and in Alberta, Canada. Neither has moved beyond the study phase because of the large investment costs required, coupled with the absence of a strong enough carbon price signal.

CO_2 pipelines are not (yet) governed by regulatory regimes like those for oil and natural gas pipelines. However, as CO_2 pipeline networks grow, they will face increasing regulation. Issues to be addressed include access, pricing, and antitrust. It should be noted that there are significant differences between the regulatory regimes for oil and for natural gas pipelines. The future regulatory regime for CO_2 pipelines will depend in part on the industrial organization of the sector. These issues are discussed in more detail by de Figueiredo et al. (2007).

As CCS scales up, it becomes more visible. Therefore, a key question is whether CCS—not only the pipeline systems but also the storage wells—can gain the public acceptance necessary for its deployment on a large scale (Brian Flannery, ExxonMobil Corporation, personal communication, August 3, 2009).

5. Subsurface uncertainty

As described earlier, industry already routinely injects large amounts of buoyant fluids like CO_2 into underground formations. As CCS is scaled up, two critical areas of uncertainty regarding these reservoirs must be addressed:

- How much storage capacity is available?
- How much CO_2 will escape and over what time frame?

Simply put, CCS at scale means that every year gigatons of CO_2 will be injected underground with the expectation that it will stay there for thousands of years. Although this is theoretically feasible (IPCC, 2005), there is a great deal of uncertainty regarding storage capacities and potential leakage.

The primary geological formations under discussion are oil and gas reservoirs, deep saline formations, and unminable coal seams:

- *Oil and gas reservoirs*. Depleted oil and gas reservoirs have proved that they can hold hydrocarbons for millions of years. This gives confidence that they can store CO_2 for a long time. Also, the dimensions and physical characteristics of these reservoirs are relatively well known. However, questions arise about whether the wells drilled into the reservoirs and the removal of the hydrocarbons have compromised their integrity. Active oil reservoirs have become a high-priority target for CCS, since CO_2 storage can be combined with EOR.
- *Deep saline formations*. Deep saline formations, both onshore and offshore, may have the greatest CO_2 storage potential. These reservoirs are the most widespread and have the largest volumes. The injected CO_2 has specific gravities in the range of 0.5 to 0.9, depending on the depth of injection. Because CO_2 is buoyant in that range, it will naturally try to rise to the top of the reservoir. Section 5.2 discusses the four major mechanisms available to contain the CO_2 in the reservoir.
- *Unminable coal seams*. Abandoned or uneconomic coal seams are another potential type of storage site. CO_2 diffuses through the pore structure of coal and is physically adsorbed to it. This process is similar to the way in which activated carbon removes impurities from air or water. However, unlike oil and gas reservoirs and saline formations, there is essentially no experience in injecting CO_2 into coal seams, and its feasibility is still a question mark.

5.1. Storage capacity

The IPCC (2005) concluded that "available evidence suggests that, it is likely that there is a technical potential of at least about 2000 $GtCO_2$ of storage capacity in geological formations." This is a large number, about two orders of magnitude greater than total annual worldwide CO_2 emissions, indicating the potential of CCS to be a significant CO_2 mitigation strategy. Some countries (e.g., the United States and Australia) have an abundance of storage capacity, while others (e.g., Japan) have limited options.

The U.S. Department of Energy (2009), in its recently completed *Carbon Sequestration Atlas of the United States and Canada,* estimates the storage capacity for oil and gas reservoirs at 82 billion metric tons CO_2. For saline formations the estimated range is 920 to 3400 billion metric tons CO_2. The high end of this range exceeds the worldwide capacity reported by the IPCC. The IPCC was being conservative in its estimates, but this difference does highlight the uncertainty involved.

The uncertainties related to geological storage have many different dimensions; the most important is that it is not known how a large quantity of CO_2 injected underground will travel and behave over time. The actual amount of CO_2 that can be stored underground is also uncertain, because little is known about the subsurface and the properties of the rocks into which the CO_2 may be injected.

It is possible, through seismic data collection, to determine the structures of formations in the subsurface, which can then inform the selection of an appropriate site for storage. However, even in a formation that will prevent the migration of CO_2, there is uncertainty about how much CO_2 can be stored effectively, as this depends on the storage efficiency of the rocks, i.e., what fraction of the pore space will effectively be available for CO_2.

Although the oil and gas industry has experience in dealing with uncertainty in the subsurface, direct experience with geological storage is limited. For example, in EOR operations the reservoirs have been characterized and modeled extensively for purposes of oil and gas extraction, but little is known about the properties of saline formations. The flow of brine through these formations would cause the migration of CO_2 that is injected, and the interactions of the brine, gas, and rock have not been explored extensively. Since these reservoirs are saturated with brines, this leads to questions about the fate of the brine that is displaced by CO_2 and the build-up of pressure in the system. These questions have yet to be answered and play a role in determining the long-term feasibility and safety of storage in the saline formations (Raza, 2009).

Nonetheless, the oil and gas industry does have significant experience with subsurface engineering for exploration, production, storage, and disposal of liquids and gases in a variety of geological settings. Operations have been adjusted over time to benefit from real-world experience with various reservoirs. One can readily imagine that similar improvements in ability to manage operations and characterize reservoirs will occur as operators gain experience with saline formations. Consequently, estimates of the capacity and cost to utilize various reservoirs for CO_2 storage likely will improve with time (Flannery, personal communication, August 3, 2009).

In summary, although the IPCC and the Department of Energy both project significant amounts of storage capacity, the exact quantity is highly uncertain. Only through extensive resource characterization and experience gained through managing actual storage projects will credible storage estimates become available.

5.2. Leakage

When CO_2 is injected into the porous rock of a formation, multiple physical phenomena allow it to remain trapped in the rock. Suitable formations are regarded as those 800 m or more below the surface, so that the increased pressure due to the depth means that the CO_2 is in a dense or supercritical phase. The rock into which the CO_2 is injected must be porous and able to store the CO_2, and there must be a layer of impermeable rock, the "cap rock," on top of the formation to ensure that the CO_2 does not rise through the rock layers and escape to the surface. With so many different physical processes occurring simultaneously, an accurate assessment of leakage potential must take into account the various trapping mechanisms, rock properties, and leakage processes.

Four trapping mechanisms contribute to the storage of CO_2 in a site:

- *Structural and stratigraphic trapping.* CO_2 is injected into a permeable reservoir, initially displacing the brine that is in the pores. The injection will generally cause a rise in pressure. This needs to be monitored to make sure it stays below the pressure at which the rock starts to fracture. CO_2 will be buoyant in this environment, causing it to rise to the top of the reservoir, where the impermeable cap rock traps it.
- *Residual CO_2 trapping.* As CO_2 flows through the reservoir, some of it gets incorporated into the soil matrix. This is called residual CO_2 trapping. CO_2 trapped in such a manner becomes immobile, and its storage can be considered permanent.
- *Solubility trapping.* Over decades to centuries, some CO_2 will dissolve in the brine. This is called solubility trapping. The timing and amount of CO_2 trapped in this manner vary from reservoir to reservoir. This trapping removes the buoyancy from the CO_2, thus reducing the likelihood of leakage. If the brine ever leaves the reservoir, CO_2 will be released. However, this usually occurs on very long time scales.
- *Mineral trapping.* Over centuries to millennia, the injected CO_2 may react with and become incorporated in the minerals in the reservoir. This is called mineral trapping and can be considered permanent storage.

A number of different mechanisms have been modeled to simulate possible leakage, and there are detailed models of leakage profiles through wells, fractures, and faults, and of diffusion through the cap rock driven by CO_2 buoyancy (Grimstad et al., 2009). Additionally, the location and size of faults away from the injection site can be modeled. Work is under way on probabilistic estimates of fault and plume interaction, looking at ways to characterize this process (Oldenburg et al., 2009).

Raza (2009) investigated the uncertainty in the location of leaks, leakage amounts, and the start of leakage times. The results showed that the leakage potential is very small, the expected value of the amount of leakage is a small fraction of the total injected volume, and the expected value of the start of leakage is over a thousand years. This suggests that geological storage at well-chosen sites offers great security over a long time frame. This analysis also indicates that fractures that are farther away from the injection site are less likely to be potential leaks, as the mobile CO_2 is less likely to reach them.

The IPCC (2005) stated that "Observations from engineered and natural analogues as well as models suggest that the fraction retained in appropriately selected and managed geological reservoirs is very likely to exceed 99% over 100 years and is likely to exceed 99% over 1000 years." They further state "for well-selected, designed and managed geological storage sites, the vast majority of the CO_2 will gradually be immobilized by various trapping mechanisms and, in that case, could be retained for up to millions of years. Because of these mechanisms, storage could become more secure over longer timeframes."

Thus, despite uncertainty about the potential leakage of CO_2 over time from geological storage reservoirs, this issue does not seem to pose a major barrier to scaling up CCS. Literature studies and expert opinion strongly indicate that some leakage may occur but will be very small and will occur far in the future. In addition, any leaks that are discovered can be mitigated and, since CO_2 is benign (except in high concentrations), the health and safety risks are minimal. Some questions remain unanswered, however:

- Can leaks be measured directly via monitoring or estimated via modeling?
- How should they be valued in a world with a price on carbon emissions?
- Who will be liable to pay the cost associated with these emissions?

These issues should be resolvable in due course with more research and experience.

6. Regulatory and legal issues

Capture and compression are well-established industrial operations that fall under long-standing rules and regulations. The only new issue that needs to be examined for capture at the gigaton scale is the implications of large-scale usage of certain chemicals. For example, if amine scrubbing becomes a dominant technology, some amines will escape the top of the absorber along with the CO_2-depleted flue gas. Although the concentration of these amines will be very low, measured in parts per million or less, investigations are currently under way to understand their impacts.

Transport of CO_2 will need to be regulated, as discussed in Section 4. Beyond this, gaining rights-of-way for pipelines is an important issue. The solution may require some sort of government action. However, this issue is not unique to CO_2 pipelines and much precedent exists.

On the other hand, geological storage does present some unique legal and regulatory issues. These can be broken down into three categories:

- legal access to the pore space used to store the CO_2
- rules for permitting and regulating CO_2 injection
- a framework for long-term stewardship, including protocols for monitoring and liability.

6.1. Legal access to the geological formation

In most of the world, the pore space is owned by the state, so this is not a major problem. However, in the United States this is not the case. Although there may be some differences between states, in general the owner of the mineral rights or surface rights will have claim to ownership of the pore space. Under the current law, the right to use the subsurface to store CO_2 would need to be acquired from every owner of subsurface to which the CO_2 plume migrates. This could become impractical in many situations, and therefore new legislation may be needed to ease this process. A detailed review of this issue can be found in de Figueiredo et al. (2007).

6.2. Rules governing CO_2 injection

The U.S. Environmental Protection Agency (EPA) has a regulatory framework in place, called the Underground Injection Control (UIC) Program, governing most types of underground injection. The UIC program was created under the Safe Drinking Water Act of 1974 and establishes requirements to ensure that underground injection activities will not endanger drinking water sources. The program regulates underground injection under five different classes of injection wells, depending on the type of fluid being injected, the purpose of the injection, and the subsurface location where the fluid is to remain. States are allowed to assume primary responsibility for implementing the UIC requirements within their borders as long as the state program is consistent with EPA regulations and has received EPA approval.

Recently, the EPA released a proposed rule for federal requirements under the UIC program for wells used in geological sequestration (GS) of CO_2.[5] The following excerpt from EPA's fact sheet[6] on the new rules is a good illustration of the issues involved in the permitting and regulation of injection operations:

> EPA's proposed rule would establish a new class of injection well—Class VI—and technical criteria for geologic site characterization; area of review and corrective action; well construction and operation; mechanical integrity testing and monitoring; well plugging; post-injection site care; and site closure for the purposes of protecting underground sources of drinking water.
> The elements of today's proposal build upon the existing UIC regulatory framework, with modifications based on the unique nature of CO_2 injection for GS, including:
>
> - Geologic site characterization to ensure that GS wells are appropriately sited;
> - Requirements to construct wells with injectate-compatible materials and in a manner that prevents fluid movement into unintended zones;
> - Periodic re-evaluation of the area of review around the injection well to incorporate monitoring and operational data and verify that the CO_2 is moving as predicted within the subsurface;
> - Testing of the mechanical integrity of the injection well, ground water monitoring, and tracking of the location of the injected CO_2 to ensure protection of underground sources of drinking water;
> - Extended post-injection monitoring and site care to track the location of the injected CO_2 and monitor subsurface pressures; and
> - Financial responsibility requirements to assure that funds will be available for well plugging, site care, closure, and emergency and remedial response.

[5] See U.S. EPA, Underground Injection Control Program, "Geologic Sequestration of Carbon Dioxide," http://www.epa.gov/safewater/uic/wells_sequestration.html/.

[6] See U.S. EPA, Office of Water, "EPA Proposes New Requirements for Geologic Sequestration of Carbon Dioxide, http://www.epa.gov/safewater/uic/pdfs/fs_uic_co2_proposedrule.pdf.

6.3. Long-term stewardship

How to provide for the long-term (centuries or longer) stewardship of and liability for the CO_2 is still an open issue. Questions need to be resolved about how to monitor the reservoir once it is closed, and for how long. Liability would arise if CO_2 leaked out and caused environmental or health problems. With regard to large release events, Heinrich et al. (2004) stated that

> it is highly unlikely that massive releases of CO_2 [like what occurred at Lake Nyos] will occur from geologic storage of CO_2. Pressure excursions should occur only near the injection point and then the CO_2 should diffuse over large areas in the formation. In other words, Lake Nyos tended to concentrate CO_2, while injection into geologic formations will tend to diffuse the CO_2 as it moves away from the injection point. With proper site selection and operation, the chances of a massive release from the formation can be reduced further.[7]

Of more concern is that a leaking CO_2 reservoir becomes a CO_2 emissions source. If a charge for CO_2 emissions is in place (through either a tax or a cap-and-trade system), someone would be liable for that charge. It has been suggested that after the site has been closed for a number of years (on the order of 10), if there have been no significant leakage or operational problems, the long-term stewardship and liability would be taken over by the government. To help pay for this, companies injecting CO_2 into the ground would pay into a liability fund (CCSReg Project, 2009).

7. Moving forward

In order to deploy CCS on a large scale, a foundation for this growth must be put in place. A series of demonstration projects will be required (MIT, 2007), as well as an economically viable policy framework and the evolution of a business model (Flannery, personal communication, August 3, 2009).

Worldwide, there need to be on the order of 10 demonstration projects, each capturing and storing on the order of a million tons of CO_2 per year (MIT, 2007). These projects should operate in a variety of geographies and geologies and demonstrate a variety of capture processes. These demonstration projects are critical for understanding the economics of these plants, generating data to inform the regulatory process, and demonstrating their feasibility and safe operation in order to gain political support and public acceptance. Another key goal is to better understand how to integrate the system components.

It is the private sector that will deploy CCS on a large scale, but how the private sector will organize to deploy CCS (i.e., what business model will be adopted) has not yet evolved. Suppliers already exist for CO_2 capture and transport, but not for CO_2 storage or long-term stewardship. In addition, a business organization needs to evolve to link the various suppliers, operators, and users throughout the CCS supply chain (Flannery, personal communication, August 3, 2009).

Another critical part of the foundation is the need to create a market for CCS. This can only be done through an economically viable policy framework for limiting emissions of CO_2. Without such framework, CO_2 will continue to be emitted into the atmosphere.

Once the foundation is in place, hopefully by 2020, CCS will be ready for large-scale deployment. It is envisioned that most new coal-fired power plants will be equipped with CCS, and a significant proportion of the existing fleet will undergo CCS retrofits. A recent study (MIT, 2009) found that about 60% of the existing coal plant fleet in the United States would be suitable for retrofitting. How fast CCS deploys and whether it reaches the gigaton scale will ultimately depend how the issues discussed in this paper play out.

[7] The statement refers to a 1986 incident at Lake Nyos, Cameroon, where naturally occurring CO_2 escaped from the lake and killed an estimated 1700 people and a large number of livestock from asphyxiation.

8. Summary and conclusions

To summarize, all the major components of a CO_2 CSS system are commercially available today. However, there is as yet no CCS industry. Even though the technological components of CCS are all in use somewhere in the economy, they do not currently function together in the way imagined as a pathway for reducing carbon emissions.

Although there are no insurmountable obstacles, there are significant challenges to address in scaling CCS up from today's megaton level to the gigaton level it needs to reach in order to help mitigate global climate change. Four challenge areas were discussed in this paper: costs, infrastructure, subsurface uncertainty, and legal and regulatory issues. In the author's opinion, the two areas of biggest concern are storage capacity and costs. It is not yet proven that enough storage capacity exists to support CCS at the gigaton scale, and the cost of CCS mitigation may be more than is politically acceptable for the next couple of decades.

Some other issues facing CCS either were not discussed in this paper or were alluded to only briefly. Of these, the most conspicuous is that of public acceptance. CCS faces the same “not in my backyard” problems as virtually every technology today. So although this is a serious issue, it is not one unique to CCS.

When looking at the challenges facing CCS, it is easy to get discouraged. However, this is the reality of all technologies available to address climate change. Developing them to the point where they operate at the necessary scale is a monumental challenge. The correct response should be not to get discouraged, but to realize that vigorous action is needed to overcome the challenges and that this action needs to be at a significant scale. Serious emissions reductions are needed soon, and developing new energy technologies takes time. Therefore, we need to start ramping up these activities right now. This is true not only for CCS, but for all the other major emissions reduction pathways as well.

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