Order Code RL33801

CRS Report for Congress

Direct Carbon Sequestration: Capturing and Storing CO_2

Updated September 13, 2007

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Prepared for Members and
Committees of Congress

Congressional
Research
Service

Direct Carbon Sequestration: Capturing and Storing CO_2

Summary

Direct sequestration is capturing carbon at its source and storing it before its release to the atmosphere. Carbon capture and storage — also known as CCS — is attracting interest as a measure for mitigating global climate change, because potentially large amounts of carbon dioxide (CO_2) emitted from fossil fuel use in the United States could be eligible for sequestration. Electricity-generating plants may be the most likely initial candidates for direct sequestration because they are predominantly large, single-point sources, and they contribute approximately one-third of U.S. CO_2 emissions from fossil fuels.

Congressional interest is growing in direct sequestration as part of legislative strategies addressing climate change. In the 110th Congress, the House and Senate have each passed bills that contain provisions expanding the current Department of Energy (DOE) carbon capture research and development program and creating new programs to accelerate R&D for CO_2 storage. The bills would require at least seven large-volume underground sequestration tests. DOE is planning to spend almost $100 million on carbon sequestration R&D in FY2007. The House- and Senate-passed bills would sharply increase that amount, doubling or tripling R&D spending on carbon sequestration within two years compared to FY2007 levels.

Approaches for capturing CO_2 are available that can potentially remove 80%-95% of CO_2 emitted from a power plant or large industrial source. Large U.S. power plants currently do not capture large volumes of CO_2 for CCS, owing to the absence of either an economic incentive or a requirement to curtail CO_2 emissions. In a CCS system, pipelines or ships will likely transport captured CO_2 from capture to storage. Three main types of geological formations are likely candidates for storing large amounts of CO_2: oil and gas reservoirs, deep saline reservoirs, and unmineable coal seams. The deep ocean also has a huge potential to store carbon; however, direct injection of CO_2 into the deep ocean is still experimental, and environmental concerns have forestalled planned experiments in the open ocean. Mineral carbonation — reacting minerals with a stream of concentrated CO_2 to form a solid carbonate — is a well understood process, but is still experimental as a viable process for storing large quantities of CO_2.

DOE's carbon sequestration research program will be facilitating field tests for carbon sequestration, with seven regional partners, across the United States. DOE is also undertaking a 10-year, $1.5 billion project — known as FutureGen — to build a power plant that integrates carbon sequestration and hydrogen production while producing 275 megawatts of electricity, enough to power about 150,000 average U.S. homes. DOE estimates direct sequestration costs of between $100 and $300 per metric ton (2,200 pounds) of carbon emissions avoided using current technologies. Power plants with CCS would require more fuel, and costs per kilowatt-hour would likely rise compared to plants without CCS.

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Introduction

Direct sequestration is capturing carbon at its source and storing it before its release to the atmosphere. Carbon capture and storage — also known as CCS — would reduce the amount of carbon dioxide (CO_2) emitted to the atmosphere while allowing the use of fossil fuels at some electricity-generating plants and industrial facilities. An integrated CCS system would include three main steps: (1) capturing and separating CO_2 at the plant; (2) transporting the captured CO_2 to the storage site; and (3) storing CO_2 in geological reservoirs or in the oceans. As a measure for mitigating global climate change, direct sequestration is attracting interest because several projects in the United States and abroad — typically associated with oil and gas production — are successfully injecting and storing CO_2 underground, albeit at relatively small scales. Also, potentially large amounts of CO_2 generated from fossil fuels — as much as one-third of the total CO_2 emitted in the United States — could be eligible for large-scale direct sequestration.[1]

Fuel combustion accounts for 94% of all U.S. CO_2 emissions.[2] Electricity generation contributes the largest proportion of CO_2 emissions compared to other types of fossil fuel use in the United States. (See **Table 1**.) Electricity-generating plants, thus, may be the most likely initial candidates for capture, separation, and storage, or reuse of CO_2 because they are predominantly large, single-point sources for emissions. Large industrial facilities, such as cement-manufacturing plants or hydrogen production plants, that already produce concentrated CO_2 streams as part of the industrial process are also good candidates for CO_2 capture and storage.[3]

Congressional interest in direct sequestration, as part of legislation addressing climate change, is growing. The House and Senate have each passed bills that contain provisions expanding the current DOE carbon capture research and development program and creating new programs to accelerate R&D for CO_2 storage. (See below.)

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[1] DOE estimates that large, fossil-fuel power plants account for one-third of all U.S. CO_2 emissions; see [http://www.fossil.energy.gov/programs/sequestration/overview.html].

[2] U.S. Environmental Protection Agency (EPA), *Inventory of U.S. Greenhouse Emissions and Sinks: 1990-2005*, p. ES-6. The percentage refers to U.S. emissions in 2005; see [http://epa.gov/climatechange/emissions/usinventoryreport.html].

[3] Intergovernmental Panel on Climate Change (IPCC) Special Report: *Carbon Dioxide Capture and Storage*, 2005. (Hereafter referred to as IPCC Special Report.)

This report covers only direct sequestration, and not indirect sequestration, whereby CO_2 is removed from the atmosphere and stored in vegetation, soils, or oceans. Forests and agricultural lands store carbon, and the world's oceans exchange huge amounts of CO_2 from the atmosphere through natural processes.[4]

Table 1. Sources for CO_2 Emissions in the United States from Combustion of Fossil Fuels

Sources	CO_2 Emissions[a]	Percent of Total
Electricity generation	2,328.7	41%
Transportation	1,892.8	34%
Industrial	840.1	15%
Residential	358.7	6%
Commercial	225.8	4%
Total	**5,646.1**	**100%**

Source: U.S. Environmental Protection Agency (EPA), *Inventory of U.S. Greenhouse Emissions and Sinks: 1990-2005*, Table ES-3; see [http://epa.gov/climatechange/emissions/usinventoryreport.html].
a. CO_2 emissions in millions of metric tons for 2005; excludes emissions from U.S. territories.

Carbon Sequestration Legislation in the 110th Congress

Several measures have been introduced in the 110th Congress that seek to expand the current federal carbon sequestration research and development program or to create new programs that accelerate research and development on capturing and storing CO_2. The House and Senate each have passed omnibus energy bills that contain carbon sequestration provisions with many similarities and some important differences. In H.R. 6, the proposed Renewable Fuels, Consumer Protection, and Energy Efficiency Act of 2007 passed by the Senate on June 21, 2007, Title III, §302, would expand the DOE program for carbon capture technology and place new emphasis on R&D for carbon storage, including at least seven large-volume sequestration tests of 1 million metric tons of carbon ($MtCO_2$)or more.[5] Section 304 in the same title would create a new program for large-scale demonstration projects that would capture CO_2 from industrial sources and sequester it in one of the seven

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[4] For more information about carbon sequestration in forests and agricultural lands, see CRS Report RL31432, *Carbon Sequestration in Forests*, by Ross Gorte; and CRS Report RL33898, *Climate Change: the Role of the U.S. Agriculture Sector*, by Renée Johnson. For more information about carbon exchanges between the oceans, atmosphere, and land surface, see CRS Report RL34059, *The Carbon Cycle: Implications for Climate Change and Congress*, by Peter Folger.

[5] One metric ton of CO_2 equivalent is written as 1 tCO_2; one million metric tons is written as 1 $MtCO_2$; one billion metric tons is written as 1 $GtCO_2$.

sequestration tests under §302, or in another storage project approved by the Secretary of Energy.

On August 4, 2007, the House passed H.R. 3221, which includes provisions under Title IV, Subtitle F, that are similar to carbon sequestration provisions in H.R. 6. Like H.R. 6, Subtitle F of H.R. 3221 would expand the DOE carbon sequestration program, put new emphasis on the storage component of R&D, include large-volume sequestration tests, and institute large-scale CO_2 capture demonstration projects from industrial facilities. In contrast to H.R. 6, the House-passed bill includes a provision for EPA to conduct a research program to assess potential impacts of CO_2 storage on the environment, and public health and safety associated with CO_2 capture and sequestration. Under H.R. 3221, the National Academy of Sciences (NAS) would review the large-scale sequestration and capture programs, beginning in 2011. Also, H.R. 3221 establishes a grant program for graduate degrees in geological sequestration science.

DOE is planning to spend approximately $100 million on the carbon sequestration program in FY2007, and these bills would authorize substantial increases over the next five years. H.R. 6, the Senate-passed bill, would authorize nearly double the $86 million DOE requested for FY2008, and H.R. 3221, the House-passed bill, nearly triples that amount, authorizing $240 million for DOE carbon sequestration R&D in FY2008. H.R. 3221 authorizes a higher level of appropriations for activities under Title IV, Subtitle F, than H.R. 6 — $1.7 billion over five years in the House-passed bill compared to $1.4 billion over six years in the Senate-passed bill. The Senate-passed bill would authorize roughly 80% of the funding levels that are authorized in the House-passed bill, and spread the authorization over six instead of five years.

Both bills contain nearly identical provisions for a new program to assess the nation's potential capacity for geological storage of $CO_{2.}$ Title VII, Subtitle D, of H.R. 3221 would establish a program in the Department of the Interior (DOI), to be carried out by the U.S. Geological Survey, that would develop a methodology for and conduct an assessment of the CO_2 storage capacity of the United States. Title III, §303, of H.R. 6 establishes a nearly identical program, and both bills authorize $30 million over five years to carry out the assessment.

The omnibus energy bills passed by both chambers incorporate carbon sequestration provisions from other legislation introduced earlier in the 110th Congress. For example, Title III of H.R. 6 derives from S. 1321, the Energy Savings Act of 2007, which in turn drew from S. 962, the Department of Energy Carbon Capture and Storage Research, Development, and Demonstration Act of 2007, and S. 731, the National Carbon Dioxide Storage Capacity Assessment Act of 2007. Similarly, H.R. 3221 includes provisions from H.R. 1933, the companion bill to S. 962, and from H.R. 1267, the companion bill to S. 731.

Capturing and Separating CO_2

The first step in direct sequestration is to produce a concentrated stream of CO_2 for transport and storage. Currently, three main approaches are available to capture CO_2 from large-scale industrial facilities or power plants: (1) post-combustion capture, (2) pre-combustion capture, and (3) oxy-fuel combustion capture. For power plants, current commercial CO_2 capture systems could operate at 85%-95% capture efficiency.[6] Techniques for capturing CO_2 have not yet been applied to large power plants (e.g., 500 megawatts or more).[7]

Post-Combustion Capture. This process involves extracting CO_2 from the flue gas following combustion of fossil fuels or biomass. Several commercially available technologies, some involving absorption using chemical solvents, can in principle be used to capture large quantities of CO_2 from flue gases. U.S. commercial electricity-generating plants currently do not capture large volumes of CO_2 because they are not required to and there are no economic incentives to do so. Nevertheless, the post-combustion capture process includes proven technologies that are commercially available today, and costs can be reasonably estimated for scaling up for a large-scale application.

Pre-Combustion Capture. This process separates CO_2 from the fuel by combining it with air and/or steam to produce hydrogen for combustion and a separate CO_2 stream that could be stored. The most common technologies today use steam reforming, in which steam is employed to extract hydrogen from natural gas.[8] In the absence of a requirement or economic incentives, pre-combustion technologies have not been used for power systems, such as natural gas combined-cycle power plants.

Pre-combustion capture of CO_2 is viewed by some as a necessary requirement for coal-to-liquid fuel processes, whereby coal can be converted through a catalyzed chemical reaction to a variety of liquid hydrocarbons. Concerns have been raised because the coal-to-liquid process releases CO_2, and the end product — the liquid fuel itself — further releases CO_2 when combusted. Several bills have been introduced in the 110th Congress that would spur coal-to-liquid fuels that proponents argue would help reduce U.S. reliance on oil imports and alleviate strained refinery capacity (and as an alternative use for coal). Pre-combustion capture during the coal-to-liquid process would reduce the total amount of CO_2 emitted, although CO_2 would still be released during combustion of the liquid fuel used for transportation or electricity generation. For more information on the coal-to-liquid process and issues for Congress, see CRS Report RL34133, *Liquid Fuels from Coal, Natural Gas, and Biomass: Background and Policy,* by Anthony Andrews.

Oxy-Fuel Combustion Capture. This process uses oxygen instead of air for combustion and produces a flue gas that is mostly CO_2 and water, which are easily separable, after which the CO_2 can be compressed, transported, and stored. This technique is still considered developmental, in part because temperatures of pure

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[6] IPCC Special Report, p. 107.

[7] IPCC Special Report, p. 25.

[8] IPCC Special Report, p. 130.

oxygen combustion (about 3,500° Celsius) are far too high for typical power plant materials.[9]

Application of these technologies to power plants generating several hundred megawatts of electricity has not yet been demonstrated. Also, up to 80% of the total costs may be associated with the capture phase of the CCS process.[10] Costs are discussed below in more detail.

Transportation

Pipelines are currently the most common method for transporting CO_2 in the United States. Over 2,500 kilometers (about 1,500 miles) of pipeline transports more than 40 $MtCO_2$ each year, predominantly to Texas, where CO_2 is used in enhanced oil recovery (EOR).[11] Transporting CO_2 in pipelines is similar to transporting petroleum products like natural gas and oil; it requires attention to design, monitoring for leaks, and protection against overpressure, especially in populated areas.[12]

Using ships may be feasible when CO_2 needs to be transported over large distances or overseas. Ships transport CO_2 today, but at a small scale because of limited demand. Liquified natural gas, propane, and butane are routinely shipped by marine tankers on a large scale worldwide. Rail cars and trucks can also transport CO_2, but this mode would probably be uneconomical for large-scale CCS operations.

Costs for pipeline transport vary, depending on construction, operation and maintenance, and other factors, including right-of-way costs, regulatory fees, and more. The quantity and distance transported will mostly determine costs, which will also depend on whether the pipeline is onshore or offshore, the level of congestion along the route, and whether mountains, large rivers, or frozen ground are encountered. Shipping costs are unknown in any detail, however, because no large-scale CO_2 transport system (in $MtCO_2$ per year, for example) is operating. Ship costs might be lower than pipeline transport for distances greater than 1,000 kilometers and for less than a few $MtCO_2$ transported per year.[13]

Even though regional CO_2 pipeline networks currently operate in the United States for enhanced oil recovery (EOR), developing a more expansive network for CCS could pose numerous regulatory and economic challenges. Some of these include questions about pipeline network requirements, economic regulation, utility cost recovery, regulatory classification of CO_2 itself, and pipeline safety. These issues are discussed in more detail in CRS Report RL33971, *Carbon Dioxide (CO_2)*

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[9] IPCC Special Report, p. 122.

[10] Steve Furnival, reservoir engineer at Senergy, Ltd., "Burying Climate Change for Good," *Physics World*; see [http://physicsweb.org/articles/world/19/9/3/1].

[11] IPCC Special Report, p. 29.

[12] IPCC Special Report, p. 181.

[13] IPCC Special Report, p. 31.

Pipelines for Carbon Sequestration: Emerging Policy Issues, by Paul W. Parfomak and Peter Folger.

Sequestration in Geological Formations

Three main types of geological formations are being considered for carbon sequestration: (1) oil and gas reservoirs, (2) deep saline reservoirs, and (3) unmineable coal seams. In each case, CO_2 would be injected, in a dense form, below ground into a porous rock formation that holds or previously held fluids. By injecting CO_2 below 800 meters in a typical reservoir, the pressure induces CO_2 to become supercritical — a relatively dense liquid — and thus less likely to migrate out of the geological formation. Injecting CO_2 into deep geological formations uses existing technologies that have been primarily developed by and used for the oil and gas industry, and that could potentially be adapted for long-term storage and monitoring of CO_2. Other underground injection applications in practice today, such as natural gas storage, deep injection of liquid wastes, and subsurface disposal of oil-field brines, can also provide information for sequestering CO_2 in geological formations.[14]

The storage capacity for CO_2 storage in geological formations is potentially huge if all the sedimentary basins in the world are considered.[15] The suitability of any particular site, however, depends on many factors including proximity to CO_2 sources and other reservoir-specific qualities like porosity, permeability, and potential for leakage. **Figure 1** is a snapshot of current or planned projects (most are associated with natural gas production) as of 2005 that involve CO_2 storage in geological formations. **Table 2** lists their characteristics. The subsections below briefly describe general characteristics of each of the three types of geological formations.

Oil and Gas Reservoirs. Pumping CO_2 into oil and gas reservoirs to boost production (enhanced oil recovery, or EOR) is practiced in the petroleum industry today. The United States is a world leader in this technology and uses approximately 32 $MtCO_2$ annually for EOR, according to DOE.[16] The advantage of using this technique for long-term CO_2 storage is that sequestration costs can be partially offset by revenues from oil and gas production. CO_2 can also be injected into oil and gas reservoirs that are completely depleted, which would serve the purpose of long-term sequestration, but without any offsetting benefit from oil and gas production. CO_2 can be stored onshore or offshore; to date, most CO_2 projects associated with EOR are onshore, with the bulk of U.S. activities in west Texas. (See **Figure 1**.)

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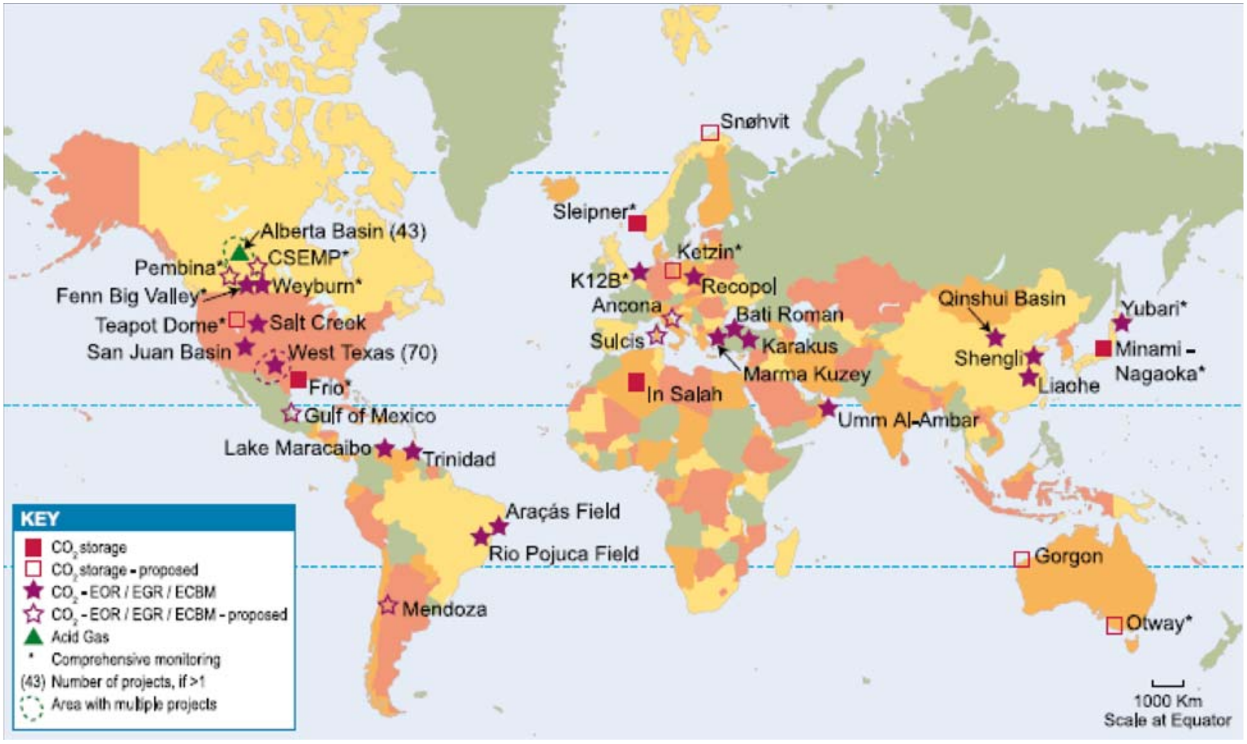
[14] IPCC Special Report, p. 31.

[15] Sedimentary basins refer to natural large-scale depressions in the Earth's surface that are filled with sediments and fluids and are therefore potential reservoirs for CO_2 storage.

[16] See [http://www.fossil.energy.gov/programs/sequestration/geologic/index.html].

Figure 1. Sites Where Activities Involving CO_2 Storage Are Planned or Underway



Source: IPCC Special Report, Figure 5.1, p. 198.
Note: EOR is enhanced oil recovery; EGR is enhanced gas recovery; ECBM is enhanced coal bed methane recovery.

Depleted or abandoned oil and gas fields, especially in the United States, are considered prime candidates for CO_2 storage for several reasons:

- oil and gas originally trapped did not escape for millions of years, demonstrating the structural integrity of the reservoir;
- extensive studies have typically characterized the geology of the reservoir;
- computer models have often been developed to understand how hydrocarbons move in the reservoir, and the models could be applied to predicting how CO_2 could move; and
- infrastructure and wells from oil and gas extraction may be in place and might be used for handling CO_2 storage.

Table 2. Current and Planned CO_2 Storage Projects

Project	Country	Scale of Project	Lead organizations	Injection start date	Approximate average daily injection rate	Total storage	Storage type	Geological storage formation	Age of formation	Lithology	Monitoring
Sleipner	Norway	Commercial	Statoil, IEA	1996	3000 t per day	20 Mt planned	Saline formation	Utsira Formation	Tertiary	Sandstone	4D seismic plus gravity
Weyburn	Canada	Commercial	EnCana, IEA	May 2000	3-5000 t per day	20 Mt planned	CO_2-EOR	Midale Formation	Mississippian	Carbonate	Comprehensive
Minami-Nagoaka	Japan	Demo	Research Institute of Innovative Technology for the Earth	2002	Max 40 t per day	10,000 t planned	Saline formation (Sth. Nagoaka Gas Field)	Haizume Formation	Pleistocene	Sandstone	Crosswell seismic + well monitoring
Yubari	Japan	Demo	Japanese Ministry of Economy, Trade and Industry	2004	10 t per day	200 t Planned	CO_2-ECBM	Yubari Formation (Ishikari Coal Basin)	Tertiary	Coal	Comprehensive
In Salah	Algeria	Commercial	Sonatrach, BP, Statoil	2004	3-4000 t per day	17 Mt planned	Depleted hydrocarbon reservoirs	Krechba Formation	Carboniferous	Sandstone	Planned comprehensive
Frio	USA	Pilot	Bureau of Economic Geology of the University of Texas	Oct. 4-13, 2004	Approx. 177 t per day for 9 days	1600t	Saline formation	Frio Formation	Tertiary	Brine-bearing sandstone-shale	Comprehensive
K12B	Netherlands	Demo	Gaz de France	2004	100-1000 t per day (2006+)	Approx 8 Mt	EGR	Rotleigendes	Permian	Sandstone	Comprehensive
Fenn Big Valley	Canada	Pilot	Alberta Research Council	1998	50 t per day	200 t	CO_2-ECBM	Mannville Group	Cretaceous	Coal	P, T, flow
Recopol	Poland	Pilot	TNO-NITG (Netherlands)	2003	1 t per day	10 t	CO_2-ECBM	Silesian Basin	Carboniferous	Coal	

Project	**Country**	**Scale of Project**	**Lead organizations**	**Injection start date**	**Approximate average daily injection rate**	**Total storage**	**Storage type**	**Geological storage formation**	**Age of formation**	**Lithology**	**Monitoring**
Qinshui Basin	China	Pilot	Alberta Research Council	2003	30 t per day	150 t	CO_2-ECBM	Shanxi Formation	Carboniferous-Permian	Coal	P, T, flow
Salt Creek	USA	Commercial	Anadarko	2004	5-6000 t per day	27 Mt	CO_2-EOR	Frontier	Cretaceous	Sandstone	Under development
Planned Projects (2005 onwards)											
Snøhvit	Norway	Decided Commercial	Statoil	2006	2000 t per day		Saline formation	Tubaen Formation	Lower Jurassic	Sandstone	Under development
Gorgon	Australia	Planned Commercial	Chevron	Planned 2009	Approx. 10,000 t per day		Saline formation	Dupuy Formation	Late Jurassic	Massive sandstone	Under development
Ketzin	Germany	Demo	GFZ Potsdam	2006	100 t per day	60 kt	Saline formation	Stuttgart Formation	Triassic	Sandstone	Comprehensive
Otway	Australia	Pilot	CO2CRC	Planned late 2005	160 t per day for 2 years	0.1 Mt	Saline fm and depleted gas field	Waarre Formation	Cretaceous	Sandstone	Comprehensive
Teapot Dome	USA	Proposed Demo	RMOTC	Proposed 2006	170 t per day for 3 months	10 kt	Saline fm and CO_2-EOR	Tensleep and Red Peak Fm	Permian	Sandstone	Comprehensive
CSEMP	Canada	Pilot	Suncor Energy	2005	50 t per day	10 kt	CO_2-ECBM	Ardley Fm	Tertiary	Coal	Comprehensive
Pembina	Canada	Pilot	Penn West	2005	50 t per day	50 kt	CO_2-EOR	Cardium Fm	Cretaceous	Sandstone	Comprehensive

Source: IPCC Special Report, Table 5.1, p. 201.

Note: EOR is enhanced oil recovery; EGR is enhanced gas recovery; ECBM is enhanced coal bed methane recovery.

Some of these features could also be disadvantages to CO_2 sequestration. Wells that penetrate from the surface to the reservoir could be conduits for CO_2 release if they are not plugged properly. Care must be taken not to overpressure the reservoir during CO_2 injection, which could fracture the caprock — the part of the formation that formed a seal to trap oil and gas — and subsequently allow CO_2 to escape. Also, shallow oil and gas fields (those less than 800 meters deep, for example) may be unsuitable because CO_2 may form a gas instead of a denser liquid and could escape to the surface more easily.

The In Salah Project in Algeria is the world's first large-scale effort to store CO_2 in a gas reservoir.[17] (See **Table 2**.) At In Salah, CO_2 is separated from the produced natural gas and then reinjected into the same formation. Approximately 17 $MtCO_2$ are planned to be captured and stored over the lifetime of the project.

The Weyburn Project in south-central Canada uses CO_2 produced from a coal gasification plant in North Dakota for EOR, injecting up to 5,000 tCO_2 per day into the formation and recovering oil.[18] (See **Table 2**.) Approximately 20 $MtCO_2$ are expected to remain in the formation over the lifetime of the project.

Table 3 shows that the global potential for CO_2 storage in oil and gas fields may be 900 $GtCO_2$. According to DOE, potential storage capacity in the United States is approximately 80 Gt CO_2, roughly 10% of world potential. (See **Table 4**.)

Table 3. Estimated Global Capacity for CO_2 Storage in Three Different Geological Formations

(annual CO_2 emissions for the U.S. and globally are shown for comparison)

Reservoir type	Lower estimate of storage capacity ($GtCO_2$)	Upper estimate of storage capacity ($GtCO_2$)	CO_2 from combustion of fossil fuels ($GtCO_2$)
Oil and gas fields	675	900	—
Deep saline formations	1000	10,000[a]	—
Unmineable coal seams	3	200	—
United States[b]	—	—	5.65
Global[c]	—	—	27.0

Sources: IPCC Special Report, Table 5.2, p. 221; U.S. Energy Information Agency; see [http://www.eia.doe.gov/pub/international/iealf/tableh1co2.xls]; U.S. Environmental Protection Agency (EPA), *Inventory of U.S. Greenhouse Emissions and Sinks: 1990-2005*.

a. The IPCC Special Report indicates that this number (10,000 $GtCO_2$) is highly uncertain.

b. U.S. CO_2 emissions in 2005.

c. Global CO_2 emissions in 2004 (including the United States).

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[17] IPCC Special Report, p. 203.

[18] IPCC Special Report, p. 204.

Deep Saline Reservoirs. Some rocks in sedimentary basins are saturated with brines or brackish water unsuitable for agriculture or drinking. As with oil and gas, deep saline reservoirs can be found onshore and offshore; in fact, they are often part of oil and gas reservoirs and share many characteristics. The oil industry routinely injects brines recovered during oil production into saline reservoirs for disposal.[19] Using saline reservoirs for CO_2 sequestration has several advantages:

- They are more widespread in the United States than oil and gas reservoirs and thus have greater probability of being close to large point sources of CO_2.
- Saline reservoirs have potentially the largest reservoir capacity of the three types of geologic formations (at least 1,000 $GtCO_2$, and possibly ten times that globally; see **Table 3**).[20] DOE estimates that the U.S. storage capacity in saline reservoirs could range from 900 to 1,000 $GtCO_2$. (See **Table 4**.)

The Sleipner Project in the North Sea is the first commercial-scale operation for sequestering CO_2 in a deep saline reservoir (see **Table 2**.) As of 2005, Sleipner has stored more than 7 $MtCO_2$. Carbon dioxide is separated from natural gas production at the nearby Sleipner West Gas Field, then injected 800 meters below the seabed of the North Sea into a saline formation at 2,700 tCO_2 per day. Monitoring has indicated the CO_2 has not leaked from the saline reservoir, and computer simulations suggest that the CO_2 will eventually dissolve into the saline water, further reducing the potential for leakage.

Large CO_2 sequestration projects, similar to Sleipner, are being planned in western Australia (the Gorgon Project) and in the Barents Sea (the Snohvits Project), that will inject 10,000 and 2,000 tCO_2 per day, respectively, when at capacity. (See **Figure 1** and **Table 2**.) Both projects plan to strip CO_2 from produced natural gas and inject it into deep saline formations for permanent storage.

Although deep saline reservoirs have huge potential capacity to store CO_2 (**Table 3**), estimates of lower and upper capacities vary greatly, reflecting a high degree of uncertainty in how to measure storage capacity.[21] Actual storage capacity may have to be determined on a case-by-case basis.

In addition, some studies have pointed out potential problems with maintaining the integrity of the reservoir because of chemical reactions following CO_2 injection. Injecting CO_2 can acidify (lower the pH of) the fluids in the reservoir, dissolving minerals such as calcium carbonate, and possibly increasing permeability. Increased permeability could allow CO_2-rich fluids to escape the reservoir along new pathways and contaminate aquifers used for drinking water.

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[19] DOE Office of Fossil Energy; see [http://www.fossil.energy.gov/programs/sequestration/geologic/index.html].

[20] IPCC Special Report, p. 223.

[21] IPCC Special Report, p. 223.

In an October 2004 experiment, researchers injected 1,600 tCO_2 1,500 meters deep into the Frio Formation — a saline reservoir containing oil and gas — along the Gulf Coast near Dayton, TX, to test its performance for CO_2 sequestration and storage.[22] Test results indicated that calcium carbonate and other minerals rapidly dissolved following injection of the CO_2. The researchers also measured increased concentrations of iron and manganese in the reservoir fluids, suggesting that the dissolved minerals had high concentrations of those metals. The results raised the possibility that toxic metals and other compounds might be liberated if CO_2 injection dissolved minerals that held high concentrations of those substances.

Another concern is whether the injected fluids, with pH lowered by CO_2, would dissolve cement used to seal the injection wells that pierce the formation from the ground surface. Leaky injection wells could then also become pathways for CO_2-rich fluids to migrate out of the saline formation and contaminate fresher groundwater above. Approximately six months after the injection experiment at the Dayton site, however, researchers did not detect any leakage upwards into the overlying formation, suggesting that the integrity of the saline reservoir formation remained intact at that time.

Preliminary results from a second injection test in the Frio Formation appear to replicate results from the first experiment, indicating that the integrity of the saline reservoir formation remained intact, and that the researchers could detect migration of the CO_2-rich plume from the injection point to the observation well in the target zone. These results suggest to the researchers that they have the data and experimental tools to move to the next, larger-scale, phase of CO_2 injection experiments.[23]

Unmineable Coal Seams. **Table 3** shows that up to 200 $GtCO_2$ could be stored in unmineable coal seams around the globe. According to DOE, nearly 90% of U.S. coal resources are not mineable with current technology, because the coal beds are not thick enough, the beds are too deep, or the structural integrity of the coal bed[24] is inadequate for mining. Even if they cannot be mined, coal beds are commonly permeable and can trap gases, such as methane, which can be extracted (a resource known as coal bed methane, or CBM). Methane and other gases are physically bound (adsorbed) to the coal. Studies indicate that CO_2 binds even more tightly to coal than methane.[25] Carbon dioxide injected into permeable coal seams could displace methane, which could be recovered by wells and brought to the surface, providing a source of revenue to offset the costs of CO_2 injection.

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[22] Y. K. Kharaka, et al., "Gas-water interactions in the Frio Formation following CO_2 injection: implications for the storage of greenhouse gases in sedimentary basins," *Geology*, v. 34, no. 7 (July, 2006), pp. 577-580.

[23] Personal communication with Susan D. Hovorka, principal investigator for the Frio Project, Bureau of Economic Geology, Jackson School of Geosciences, University of Texas at Austin, August 22, 2007.

[24] *Coal bed* and *coal seam* are interchangeable terms.

[25] IPCC Special Report, p. 217.

According to DOE, between 150 and 170 Gt CO_2 could be stored in unmineable coal seams in the United States and parts of Canada. (See **Table 4**.) That estimate represents a significant increase from estimates for North America provided in the IPCC Special Report, and is a significant fraction of the global potential for coal-seam storage estimated by IPCC. Not all types of coal beds are suitable for CBM extraction, however. Without the coal bed methane resource, the sequestration process would be less economically attractive. Given economic considerations, total CO_2 storage capacity in North America may be less than the DOE projections.

Unmineable coal seam injection projects will need to assess several factors in addition to the potential for CBM extraction. These include depth, permeability, coal bed geometry (a few thick seams, not several thin seams), lateral continuity and vertical isolation (less potential for upward leakage), and other considerations. Once CO_2 is injected into a coal seam, it will likely remain there unless the seam is depressurized or the coal is mined. Also, many unmineable coal seams in the United States are located near electricity-generating facilities, which could reduce the distance and cost of transporting CO_2 from large point sources to storage sites.

Carbon dioxide injection into coal beds has been successful in the Alberta Basin, Canada, and in a pilot project in the San Juan Basin of northern New Mexico. (See **Figure 1**.) However, no commercial CO_2 injection and sequestration project in coal beds is currently underway. Without ongoing commercial experience, storing CO_2 in coal seams has significant uncertainties compared to the other two types of geological storage discussed. According to IPCC, unmineable coal seams have the smallest potential capacity for storing CO_2 globally compared to oil and gas fields or deep saline formations. However, DOE indicates that unmineable coal seams in the United States have nearly double the capacity of oil and gas fields for storing CO_2. The discrepancy could represent the relatively abundant U.S. coal reserves compared to other regions in the world, or might also indicate the uncertainty in estimating the CO_2 storage capacity in unmineable coal seams.

Geological Storage Capacity for CO_2 in the United States

In March 2007, DOE's National Energy Technology Laboratory (NETL) released an assessment of geological sequestration potential across the United States and parts of Canada.[26] According to DOE, the Carbon Sequestration Atlas represents the first coordinated assessment of carbon sequestration potential, and includes the most current and best available estimates of CO_2 sequestration potential determined by a consistent methodology. However, DOE also notes that some areas of the United States yielded more and better-quality data than others, and acknowledges that the data sets are not comprehensive. **Table 4** shows the estimates broken down by the three types discussed above: oil and gas reservoirs, deep saline formations, and unmineable coal seams.

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[26] U.S. Dept. of Energy, National Energy Technology Laboratory, *Carbon Sequestration Atlas of the United States and Canada*, March, 2007, 86 pages; see [http://www.netl.doe.gov/publications/carbon_seq/atlas/index.html]. Hereafter referred to as the Carbon Sequestration Atlas. For an interactive version of the Carbon Sequestration Atlas and its underlying data, see the National Carbon Sequestration Database and Geographical Information System (NATCARB) at [http://www.natcarb.org].

Table 4 indicates a lower and upper range for sequestration potential in deep saline formations and for unmineable coal seams, but only a single estimate for oil and gas fields. The Carbon Sequestration Atlas explains that a range of sequestration capacity for oil and gas reservoirs is not provided — in contrast to deep saline formations and coal seams — because of the relatively good understanding of oil and gas field volumetrics.[27] Although it is widely accepted that oil and gas reservoirs are better understood, primarily because of the long history of oil and gas exploration and development, it seems unlikely that the capacity for CO_2 storage in oil and gas formations is known to the level of precision stated in the Carbon Sequestration Atlas. It is likely that the estimate of 82.4 $GtCO_2$ shown in **Table 4** may change, for example, pending the results of large-scale CO_2 injection tests in oil and gas fields.

The Carbon Sequestration Atlas was compiled from estimates of geological storage capacity made by seven separate regional partnerships, government-industry collaborations fostered by DOE, that each produced estimates for different regions of the United States and parts of Canada. According to DOE, geographical differences in fossil fuel use and sequestration potential across the country led to a regional approach to assessing CO_2 sequestration potential.[28] The Carbon Sequestration Atlas reflects some of the regional differences; for example, not all of the regional partnerships identified unmineable coal seams as potential CO_2 reservoirs. Other partnerships identified geological formations unique to their regions — such as organic-rich shales in the Illinois Basin, or flood basalts in the Columbia River Plateau — as other types of possible reservoirs for CO_2 storage.

Table 4. Geological Sequestration Potential for the United States and Parts of Canada

Reservoir type	**Lower estimate of storage capacity ($GtCO_2$)**	**Upper estimate of storage capacity ($GtCO_2$)**
Oil and gas fields[a]	82.4	—
Deep saline formations	919.0	3,378.0
Unmineable coal seams	156.1	183.5

Source: Carbon Sequestration Atlas.
a. According to DOE, oil and gas fields are sufficiently well-understood that no range of values for storage capacity is given.

The Carbon Sequestration Atlas contains a discussion of the methodology used to construct the estimates; however, because each partnership produced its own estimates of reservoir capacity, some observers have raised the issue of consistency among estimates across the regions. Partly because of those concerns, some interests support legislation, contained in Senate-passed H.R. 6 and House-passed H.R. 1321 (discussed above), that shifts the responsibility for developing a single methodology

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[27] Carbon Sequestration Atlas, p. 12.

[28] Carbon Sequestration Atlas, p. 6.

and for conducting a national geological carbon sequestration assessment to the U.S. Geological Survey within the Department of the Interior. The DOE regional partnerships are discussed in more detail later in this report.

Deep Ocean Sequestration

The world's oceans contain approximately 50 times the amount of carbon stored in the atmosphere and nearly 20 times the amount stored in plants and soils.[29] The oceans today take up — act as a net sink for — approximately 1.7 Gt CO_2 per year, and have stored approximately one-third, or more than 500 $GtCO_2$, of the total CO_2 released by humans to the atmosphere over the past 200 years.[30] Over time, experts predict that most CO_2 released to the atmosphere from fossil fuel combustion will eventually be absorbed in the ocean, but the rate of uptake depends on how fast the ocean mixes the surface waters with the deep ocean, a process that takes decades to centuries.

Injecting CO_2 directly into the deep ocean is considered a potentially viable process for long-term sequestration of large amounts of captured CO_2. The potential for ocean storage of captured CO_2 is huge, on the order of thousands of $GtCO_2$, but environmental impacts on marine ecosystems and other issues may determine whether large quantities of captured CO_2 will ultimately be stored in the oceans.

Direct Injection. Injecting CO_2 directly into the ocean would take advantage of the slow rate of mixing, allowing the injected CO_2 to remain sequestered until the surface and deep waters mix and CO_2 concentrations equilibrate with the atmosphere. What happens to the CO_2 would depend on how it is released into the ocean, the depth of injection, and the temperature of the seawater. The fraction of CO_2 stored and retained in the ocean tends to be higher with deeper injection. **Table 4** shows estimates of the percent of CO_2 retained in the ocean, over time, for different injection depths according to one set of ocean models.

Table 5. Fraction of CO_2 Retained for Ocean Storage

Year	Injection depth 800 m[a]	1500 m[b]	3000 m[c]
2100	78%	91%	99%
2200	50%	74%	94%
2300	36%	60%	87%
2400	28%	49%	79%
2500	23%	42%	71%

Source: IPCC Special Report, Table TS.7, p. 38.
Note: Models assume 100 years of continuous injection at three different depths beginning in 2000.
a. For 800 meter depths, model results vary by 6-7%.
b. For 1,500 meter depths, model results vary by 5-9%.
c. For 3,000 meter depths, model results vary by 1-14%.

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[29] IPCC Special Report, p. 281.

[30] IPCC Special Report, p. 37.

Carbon dioxide injected above 500 meters in depth typically would be released as a gas, and would rise towards the surface. Most of it would dissolve into seawater if the injected CO_2 gas bubbles were small enough.[31] Below 500 meters in depth, CO_2 can exist as a liquid in the ocean, although it is less dense than seawater. After injection at 500 meters, CO_2 would also rise, but an estimated 90% would dissolve in the first 200 meters. Below 3,000 meters in depth, CO_2 is a liquid and is denser than seawater; the injected CO_2 would sink and dissolve in the water column or possibly form a CO_2 pool or lake on the sea bottom. Some researchers have proposed injecting CO_2 into the ocean bottom sediments below depths of 3,000 meters, and immobilizing the CO_2 as a dense liquid or solid CO_2 hydrate.[32] Deep storage in ocean bottom sediments, below 3,000 meters in depth, might potentially sequester CO_2 for thousands of years.[33]

Limitations to Deep Ocean Sequestration. In addition to uncertainties about cost, other concerns about storing CO_2 in the oceans include the length of time that injected CO_2 remains in the ocean, the quantity retained, and environmental impacts from elevated CO_2 concentrations in the seawater. Also, deep ocean storage is in a research stage. The types of problems associated with scaling up from small research experiments, using less than 100 liters of CO_2,[34] to injecting several $GtCO_2$ into the deep ocean are unknown.

Injecting CO_2 into the deep ocean would change ocean chemistry, locally at first, and assuming hundreds of $GtCO_2$ were injected, would eventually produce measurable changes over the entire ocean. The most significant and immediate effect would be the lowering of pH, increasing the acidity of the water. A lower pH may harm some ocean organisms, depending on the magnitude of the pH change and the type of organism. Actual impacts of deep sea CO_2 sequestration are largely unknown, however, because scientists know very little about deep ocean ecosystems.[35]

Environmental concerns led to the cancellation of the largest planned experiment to test the feasibility of ocean sequestration in 2002. A scientific consortium had planned to inject 60 tCO_2 into water over 800 meters deep near the Kona coast on the island of Hawaii. Environmental organizations opposed the experiment on the grounds that it would acidify Hawaii's fishing grounds, and that

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[31] IPCC Special Report, p. 285.

[32] A *CO_2 hydrate* is a crystalline compound formed at high pressures and low temperatures by trapping CO_2 molecules in a cage of water molecules.

[33] K. Z. House, et al., "Permanent carbon dioxide storage in deep-sea sediments," *Proceedings of the National Academy of Science*s, vol. 103, no. 33 (Aug. 15, 2006): pp. 12291-12295.

[34] P. G. Brewer, et al., "Deep ocean experiments with fossil fuel carbon dioxide: creation and sensing of a controlled plume at 4 km depth," *Journal of Marine Research*, vol. 63, no. 1 (2005): p. 9-33.

[35] IPCC Special Report, p. 298.

it would divert attention from reducing greenhouse gas emissions.[36] A similar but smaller project with plans to release more than 5 tCO_2 into the deep ocean off the coast of Norway, also in 2002, was cancelled by the Norway Ministry of the Environment after opposition from environmental groups.[37]

Mineral Carbonation

Another option for sequestering CO_2 produced by fossil fuel combustion involves converting CO_2 to solid inorganic carbonates, such as $CaCO_3$ (limestone), using chemical reactions. This process, known as "weathering," also occurs naturally but takes place over thousands or millions of years. The process can be accelerated by reacting a high concentration of CO_2 with minerals found in large quantities on the Earth's surface, such as olivine or serpentine.[38] Mineral carbonation has the advantage of sequestering carbon in solid, stable minerals that can be stored without risk of releasing carbon to the atmosphere over geologic time scales.

Mineral carbonation involves three major activities: (1) preparing the reactant minerals — mining, crushing, and milling — and transporting them to a processing plant, (2) reacting the concentrated CO_2 stream with the prepared minerals, and (3) separating the carbonate products and storing them in a suitable repository.

Mineral carbonation is well understood and can be applied at small scales, but is at an early phase of development as a technique for sequestering large amounts of captured CO_2. Large volumes of silicate oxide minerals are needed, from 1.6 to 3.7 tonnes (metric tons) of silicates per tCO_2 sequestered. Thus, a large-scale mineral carbonation process needs a large mining operation to provide the reactant minerals in sufficient quantity.[39] Large volumes of solid material would also be produced, between 2.6 and 4.7 tonnes of materials per tCO_2 sequestered, or 50%-100% more material to be disposed of by volume than originally mined. Because mineral carbonation is in the research and experimental stage, reasonably estimating the amount of CO_2 that could be sequestered by this technique is difficult.

One possible geological reservoir for CO_2 storage — major flood basalts[40] such as those on the Columbia River Plateau — is being explored for its potential to react with CO_2 and form solid carbonates *in situ* (in place). Instead of mining, crushing,

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[36] Virginia Gewin, "Ocean carbon study to quit Hawaii," *Nature*, vol. 417 (June 27, 2002): p. 888.

[37] Jim Giles, "Norway sinks ocean carbon study," *Nature*, vol. 419 (Sep. 5, 2002): p. 6.

[38] Serpentine and olivine are silicate oxide minerals — combinations of the silica, oxygen, and magnesium — that react with CO_2 to form magnesium carbonates. Wollastonite, a silica oxide mineral containing calcium, reacts with CO_2 to form calcium carbonate (limestone). Magnesium and calcium carbonates are stable minerals over long time scales.

[39] IPCC Special Report, p. 40.

[40] Flood basalts are vast expanses of solidified lava, commonly containing olivine, that erupted over large regions in several locations around the globe. In addition to the Columbia River Plateau flood basalts, other well-known flood basalts include the Deccan Traps in India and the Siberian Traps in Russia.

and milling the reactant minerals, as discussed above, CO_2 would be injected directly into the basalt formations and would react with the rock over time and at depth to form solid carbonate minerals. Large and thick formations of flood basalts occur globally, and may have characteristics — such as high porosity and permeability — that are favorable to storing CO_2. Those characteristics, combined with tendency of basalt to react with $CO_{2,}$ could result in a large-scale conversion of the gas into stable, solid minerals that would remain underground for geologic time. One of the DOE regional carbon sequestration partnerships is exploring the possibility for using Columbia River Plateau flood basalts for storing CO_2; however, investigations are in a preliminary stage.[41]

Costs for Direct Sequestration

According to one DOE estimate, sequestration costs for capture, transport, and storage range from \$100 to \$300 per tonne of carbon emissions avoided using present technology.[42] In most carbon sequestration systems, the cost of capturing CO_2 is the largest component, possibly accounting for as much as 80% of the total.[43] Cost information is sparse for large, integrated, commercial CCS systems because few are currently operating, but estimates are available for the components of hypothetical systems. **Table 6** shows a range of estimated costs of each component of a CCS system, using data from 2002, and assuming that prices for geological storage are not offset by revenues from enhanced oil recovery or coal bed methane extraction.

The wide range of costs for each component reflects the wide variability of site-specific factors. With the exception of certain industrial applications, such as capturing CO_2 from natural gas production facilities (see Sleipner example, above), CCS has not been used at a large scale. To date, no large electricity-generating plants, the likely candidates for large-scale carbon sequestration, have incorporated CCS. Retrofitting existing plants with CO_2 capture systems would probably lead to higher costs than newly built power plants that incorporate CCS systems, and industrial sources of CO_2 may be more easily retrofitted. Cost disadvantages of retrofitting may be reduced for relative new and highly efficient existing plants.[44]

Capturing CO_2 at electricity-generating power plants will likely require more energy, per unit of power output, than required by plants without CCS. The additional energy required also means that more CO_2 would be produced, per unit of power output. As a result, plants with CCS would be less efficient than plants without CCS. Comparisons of costs between power plants with and without CCS often include "avoided CO_2 emissions" as well as captured CO_2 emissions. Avoided CO_2 emissions takes into account the additional fuel needed to generate the additional energy required to capture CO_2. Appendix A provides more information about avoided versus captured CO_2 emissions.

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[41] Carbon Sequestration Atlas, p. 23.

[42] Equivalent to \$27 to \$82 per tCO_2 emissions avoided; see [http://www.fossil.energy.gov/programs/sequestration/overview.html].

[43] Furnival, "Burying Climate Change for Good."

[44] IPCC Special Report, p. 10.

Table 6. Estimated Cost Ranges for Components of a Carbon Capture and Storage System

(data from 2002)

CCS system components	Cost range	Remarks
Capture from a coal- or gas-fired power plant	15-75 US$/t$CO_2$ net captured	Net costs of captured CO_2, compared to the same plant without capture.
Capture from hydrogen and ammonia production or gas processing	5-55 US$/t$CO_2$ net captured	Applies to high-purity sources requiring simple drying and compression.
Capture from other industrial sources	25-115 US$/t$CO_2$ net captured	Range reflects use of a number of different technologies and fuels.
Transportation	1-8 US$/t$CO_2$ transported	Per 250 km pipeline or shipping for mass flow rates of 5 (high end) to 40 (low end) MtCO_2 per year.
Geological storage	0.5-8 US$/t$CO_2$ net injected	Excluding potential revenues from EOR or ECBM.
Geological storage: monitoring and verification	0.1-0.3 US$/t$CO_2$ injected	This covers pre-injection, injection, and post-injection monitoring, and depends on the regulatory requirements.
Ocean storage	5-30 US$/t$CO_2$ net injected	Including offshore transportation of 100-500 km, excluding monitoring and verification.
Mineral carbonation	50-100 US$/t$CO_2$ net mineralized	Range for the best case studied. Includes additional energy use for carbonation.

Source: IPCC Special Report, Table TS.9, p. 42.

Note: Costs are as applied to a type of power plant or industrial source, and represent costs for large-scale, new installations, with assumed gas prices of $3-4.75 per MCF (thousand cubic feet), and assumed coal prices of $21.80-32.70 per short ton (2,000 pounds).

Table 7 compares CO_2 avoided versus CO_2 captured for three different types of power plants, and the increased fuel required for capturing CO_2 at the plant. **Table 8** compares the cost of electricity for plants without CCS against plants with CCS.

A 2007 DOE study of the cost and performance baseline for fossil energy plants estimated that the total costs of CO_2 avoided for three different types of plants were as follows: $74.8 per tonne for pulverized coal (PC) plants; $42.9 per tonne for integrated coal gasification combined cycle plants (IGCC); and $91.3 per tonne for natural gas combined cycle plants (NGCC).[45] The report noted that costs for CO_2 avoided in IGCC plants are substantially less than for the other two types of plants because CO_2 removal takes place prior to combustion and at high pressures using physical absorption. Costs of CO_2 avoided are higher for NGCC plants because baseline emissions for NGCC plants are 46% lower than IGCC plants; thus costs for removing additional CO_2 in NGCC plants are proportionately higher.

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[45] DOE/National Energy Technology Laboratory, *Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Final Repor*t, DOE/NETL 2007/1281 (May, 2007), p. 15.

Table 7. Comparison of CO_2 Captured Versus CO_2 Avoided for New Power Plants

Power plants	Pulverized coal	Natural gas combined cycle	Integrated coal gasification combined cycle
CO_2 captured	0.82-0.97 kg/kWh	0.36-0.41 kg/kWh	0.67-0.94 kg/kWh
CO_2 avoided	0.62-0.70 kg/kWh	0.30-0.32 kg/kWh	0.59-0.73 kg/kWh
Increased fuel requirement for capture	24-40%	11-22%	14-25%

Source: From IPCC Special Report, Table 8.3a, p. 347.
Note: kWh is kilowatt hour; kg is kilogram.

Table 8. Comparison of Electricity Costs for New Power Plants With and Without Carbon Capture and Geological Storage

Power plants	Pulverized coal	Natural gas combined cycle	Integrated coal gasification combined cycle
Cost of electricity (plant without CCS)	0.043-0.052 $/kWh	0.031-0.050 $/kWh	0.041-0.061 $/kWh
Cost of electricity (plant with CCS)	0.063-0.099 $/kWh	0.043-0.077 $/kWh	0.055-0.091 $/kWh
Cost increase	47%-90%	39%-54%	34%-49%

Source: From IPCC Special Report, Table 8.3a, p. 347.

DOE states that the goal of its carbon sequestration program is to reduce costs to $10 or less per tonne of carbon emissions avoided by 2015.[46] That goal is approximately 6% of the cost per tonne CO_2 avoided by IGCC plants according to the 2007 DOE study discussed above. Other sources suggest that costs of building and operating CO_2 capture systems will decline over time with sustained research and development, and with technological improvements.[47] Nevertheless, DOE's goal would require reducing costs for CCS by over 90% from today's lower-end cost estimates in less than 10 years.

Costs of capturing CO_2 at a large electricity-generating plant would probably dominate the overall cost of comprehensive CCS system. Thus, improving the efficiency of the CO_2 capture phase may produce the largest cost savings. However, the variability of site-specific factors, such as types and costs of fuels used by power plants, distance of transport to a storage site, and the type of CO_2 storage, also suggests that costs will vary widely from project to project.

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[46] Equivalent to $2.70 per tCO_2 avoided; see [http://www.fossil.energy.gov/programs/sequestration/overview.html].

[47] IPCC Special Report, p. 41.

Research Programs and Demonstration Projects

Figure 1 and **Table 2** list a number of geologic sequestration projects that are planned or underway around the globe. Many are commercial projects that include aspects of enhanced oil recovery and some are related to coal bed methane extraction. The U.S. petroleum industry, for example, injects 32 $MtCO_2$ per year of CO_2 underground for EOR, particularly in west Texas.[48] The Sleipner Project in Norway, using CO_2 stripped from natural gas production, sequesters approximately 3,000 tCO_2 per day in a deep saline formation. Norway's carbon tax of nearly 40 euro per tCO_2[49] was a strong economic incentive for the project; sequestration avoids nearly $50 million per year in carbon taxes.[50] The Gorgon Project in western Australia, also planning to use a deep saline formation, would inject 10,000 tCO_2 per day recovered from natural gas operations. Gorgon, expected to begin operations between 2008 and 2010, would be the world's largest CO_2 sequestration project.

In addition to the Sleipner Project, the Weyburn and In Salah Projects (discussed above) are the other two ongoing, large-scale CCS projects underway worldwide. Costs for large-scale projects and the role of national governments in supporting CCS are influencing commercial decisions about whether to pursue capturing and storing CO_2 for EOR or other purposes. For example, BP announced in May 2007 that it was cancelling a carbon capture project in Peterhead, Scotland, in which CO_2 removed from natural gas would have been injected in a North Sea oilfield for EOR. According to news reports, one factor in the company's decision was delay on the part of the British government in supporting the project.[51] BP is still pursuing its plans in the United States to build a 500 MW plant near its Carson, CA, refinery that would capture 4 $MtCO_2$ per year and reinject it for EOR. The Carson plant would convert petroleum coke, the byproduct of oil refining, to hydrogen for electricity generation and capture the CO_2 as a byproduct.

In March 2007, American Electric Power announced that it would move forward on plans for a commercial-scale CCS system at its Mountaineer Plant in West Virginia that would capture 100,000 tCO_2 per year in a post-combustion process using chilled ammonia, and inject it in a deep saline aquifer beneath the plant. The decision follows a 10-year DOE-sponsored project on the site to help develop the technology to move to a larger-scale system, and is touted as one of the success stories within the DOE Carbon Sequestration Program.[52]

DOE Carbon Sequestration Program. DOE's carbon sequestration program marks its tenth year in 2007. Spending on carbon sequestration R&D has

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[48] See [http://www.fossil.energy.gov/programs/sequestration/geologic/index.html].

[49] See CRS Report RL33581, *Climate Change: The European Union's Emissions Trading System (EU-ETS), Appendix: Norway's Trading System,* by Larry Parker.

[50] Furnival, "Burying Climate Change for Good."

[51] BBC news, May 23, 2007, at [http://news.bbc.co.uk/1/hi/scotland/north_east/6685345.stm].

[52] Energy Washington Week, "DOE Touts Success of AEP Carbon Storage Efforts," March 21, 2007.

grown to nearly $100 million[53] in FY2007 from less than $5 million in FY1997. The Administration budget proposal for FY2008 includes $86 million for the carbon sequestration R&D program (excluding funding for the FutureGen program, discussed below). The program has three main elements: (1) laboratory and pilot-scale research for developing new technologies and systems; (2) infrastructure development for future deployment of carbon sequestration using regional partnerships; and (3) support for the DOE FutureGen project, a 10-year initiative to build the world's first integrated carbon sequestration and hydrogen production power plant.

According to DOE, the overall goal of the program is to develop, by 2012, systems that will achieve 90% capture of CO_2 at less than a 10% increase in the cost of energy services and retain 99% storage permanence.[54] Developing *systems* to capture and sequester CO_2, however, differs from when CCS technologies are available for large-scale deployment and are actually deployed. In testimony before the Senate Energy and Natural Resources Committee on April 16, 2007, Thomas D. Shope, Acting Assistant Secretary for Fossil Energy at DOE, stated that under current budget constraints and outlooks CCS technologies would be available and deployable in the 2020 to 2025 timeframe. However, Mr. Shope added that "we're not going to see common, everyday deployment [of those technologies] until approximately 2045."[55]

The research aspect of the DOE program includes a combination of cost-shared projects, industry-led development projects, research grants, and research at the National Engineering Technology Laboratory. The program investigates five focus areas: (1) CO_2 capture; (2) carbon storage; (3) monitoring, mitigation, and verification; (4) work on non-CO_2 greenhouse gases; and (5) advancing breakthrough technologies.

Beginning in 2003, DOE created seven regional carbon sequestration partnerships to identify opportunities for carbon sequestration field tests in the United States and Canada.[56] The regional partnerships program is being implemented in a

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[53] DOE had originally included $74 million for the Carbon Sequestration Program in FY2007, and has made available an additional $24 million from within the DOE Fossil Energy Office, bringing the total to approximately $100 million for FY2007. Personal communication, John Litynski, DOE National Energy Technology Laboratory, August 23, 2007.

[54] DOE Carbon Sequestration Technology Roadmap and Program Plan 2007, p. 5; see [http://www.netl.doe.gov/publications/carbon_seq/project%20portfolio/2007/2007Roadmap.pdf].

[55] Testimony of Thomas D. Shope, Acting Assistant Secretary for Fossil Energy, DOE, before the Senate Energy and Natural Resources Committee, April 16, 2007; at [http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_senate_hearings&docid=f:36492.pdf].

[56] The seven partnerships are Midwest Regional Carbon Sequestration Partnership; Midwest (Illinois Basin) Geologic Sequestration Consortium; Southeast Regional Carbon Sequestration Partnership; Southwest Regional Carbon Sequestration Partnership; West (continued...)

three-phase overlapping approach: (1) characterization phase (from FY2003 to FY2005); (2) validation phase (from FY2005 to FY2009); and (3) deployment phase (from FY2008 to FY2017).[57] According to the Carbon Sequestration Atlas, the first phase of the partnership program identified the potential for sequestering over 1,000 $GtCO_2$ across the United States and parts of Canada. On October 31, 2006, DOE announced it will provide $450 million over the next 10 years for field tests in the seven regions to validate results from smaller tests in the first phase, with an additional cost share of 20% to be provided by each partnership. **Figure 2** shows the validation phase field tests by region.

The third phase, deployment, is intended to demonstrate large-volume, prolonged injection and CO_2 storage in a wide variety of geologic formations. According to DOE, this phase is supposed to address the practical aspects of large-scale operations, presumably producing the results necessary for commercial CCS activities to move forward. One possible limitation to the deployment phase is, paradoxically, access by each partnership region to large volumes of CO_2 that can be used for the large-scale injection projects. For regions nearby to currently available sources of CO_2 in large volume, such as those associated with EOR, availability of CO_2 may not be an issue. But availability could be a serious issue for other regions where CO_2 is not extracted or separated in large volumes for commercial use. That possible limitation raises the issue of timing, whether CO_2 capture technology and transportation infrastructure will be ready to supply the needed million tonnes of CO_2 per year over several years for the deployment stage tests.

FutureGen. On February 27, 2003, President Bush proposed a 10-year, $1 billion project to build a coal-fired power plant that integrates carbon sequestration and hydrogen production while producing 275 megawatts of electricity, enough to power about 150,000 average U.S. homes. The plant will be a coal-gasification facility and will produce between 1 and 2 $MtCO_2$ annually. DOE will provide most of the funding. An industry consortium, the FutureGen Industrial Alliance, Inc.,[58] is expected to contribute up to $250 million, and international partners may contribute up to 8% of the project's cost.[59] Since the original announcement, DOE has revised

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[56] (...continued)
Coast Regional Carbon Sequestration Partnership; Big Sky Regional Carbon Sequestration Partnership; and Plains CO_2 Reduction Partnership; see [http://www.fossil.energy.gov/programs/sequestration/partnerships/index.html].

[57] DOE Carbon Sequestration Technology Roadmap and Program Plan 2007, p. 36.

[58] As of Dec. 2006, 12 companies form the FutureGen Industrial Alliance: American Electric Power; Southern Company; CONSOL Energy, Inc.; Rio Into Energy America (RHEA); Peabody Energy; EON US; PAL Corporation; BHP Billiton; Foundation Coal Corp.; China Hennaing Group; Anglo American; and Xstrata Coal. See [http://www.futuregenalliance.org/].

[59] DOE report to Congress, March 2004. See [http://www.fossil.energy.gov/programs/powersystems/futuregen/futuregen_report_march_04.pdf].

its cost estimate to $1.5 billion *net* cost, calculated when anticipated revenue offsets are included.[60]

Congress directed $9 million to initiate FutureGen in the conference report (H.Rept. 108-330) for the 2004 Interior Appropriations Act. DOE spent approximately $17 million for the project in FY2006, has allocated $54 million for FutureGen in FY2007, and has requested $108 million for FY2008.

The FutureGen Industrial Alliance will conduct the first phase of the project. In July 2006, from a list of 12 sites in seven states, they announced four finalists who will compete to host the FutureGen plant.[61] In May, 2007, DOE released a draft Environmental Impact Statement (EIS) for the FutureGen project, announced it was accepting public comments through July 16, 2007, and scheduled public hearings in the four finalist sites. Following the National Environmental Policy Act review, the FutureGen Alliance will select the final site, possibly in the latter half of 2007, and issue a final EIS for the plant following site selection.

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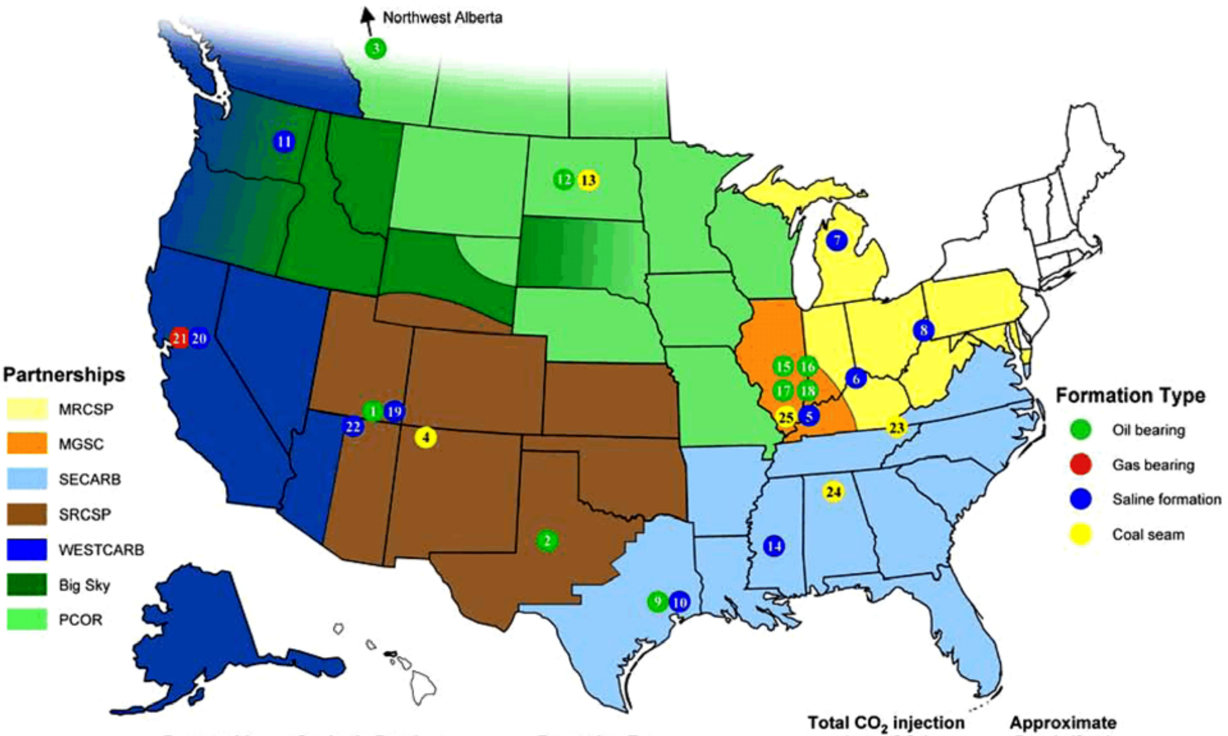
[60] See [http://www.fossil.energy.gov/programs/powersystems/futuregen/index.html].

[61] The four finalists are Mattoon, IL; Tuscola, IL; Heart of Brazos (near Jewett, TX); and Odessa, TX.

Figure 2. DOE Carbon Sequestration Program Field Tests

Validation Phase Geologic Field Tests



	Partnership	Geologic Province	Formation Type	Total CO_2 injection (tons CO_2)	Approximate Depth (feet)
①	SRCSP	Paradox Basin, Aneth Field	Oil-bearing	525,000	5,800
②	SRCSP	Permian Basin	Oil-bearing	300,000	5,700
③	PCOR	Keg River Formation	Oil-bearing	250,000 tons CO_2 w/90,000 tons H_2S	4,900
④	SRCSP	San Juan Basin	Coal seam	75,000	3,000
⑤	MGSC	Illinois Basin	Saline formation	10,000	5,000 – 9,000
⑥	MRCSP	Cincinnati Arch	Saline formation	10,000	8,000 – 10,000
⑦	MRCSP	Michigan Basin	Saline formation	10,000	4,000
⑧	MRCSP	Appalachian Basin	Saline formation	10,000	2,500 – 4,000
⑨	SECARB	Gulf Coast	Oil-bearing	7,500	8,000
⑩	SECARB	Gulf Coast	Saline formation	7,500	10,000
⑪	Big Sky	Grand Ronde Basalt	Saline formation (basalt/mafic)	3,000	2,700
⑫	PCOR	Duperow Formation	Oil-bearing	3,000	1,000
⑬	PCOR	Williston Basin	Coal seam	3,000	>500
⑭	SECARB	Mississippi Salt Basin	Saline formation	3,000	7,500
⑮	MGSC	Illinois Basin	Oil-bearing – Heavy	2,500	1,200 – 2,800
⑯	MGSC	Illinois Basin	Oil-bearing – Well Conversion	2,500	Up to 3,150
⑰	MGSC	Illinois Basin	Oil-bearing – Pattern Flood I	2,500	2,800 – 3,150
⑱	MGSC	Illinois Basin	Oil-bearing – Pattern Flood II	2,500	2,800 – 3,150
⑲	SRCSP	Paradox Basin, Aneth Field	Saline formation	2,000	6,000
⑳	WESTCARB	Central Valley CA	Saline formation	2,000	5,000
㉑	WESTCARB	Central Valley CA	Gas-bearing	2,000	4,000
㉒	WESTCARB	Kaiparowits Basin	Saline formation	2,000	8,000
㉓	SECARB	Central Appalachian	Coal seam	1,000	1,000
㉔	SECARB	Black Warrior Basin	Coal seam	1,000	2,300 – 5,000
㉕	MGSC	Illinois Basin	Coal seam	750	1,000

Source: DOE Carbon Sequestration Technology Roadmap and Program Plan 2007, Figure 22, p. 39.
Note: MRCSP is Midwest Regional Carbon Sequestration Partnership; MGSC is Midwest (Illinois Basin) Geologic Sequestration Consortium; SECARB is Southeast Regional Carbon Sequestration Partnership; SRCSP is Southwest Regional Carbon Sequestration Partnership; WESTCARB is West Coast Regional Carbon Sequestration Partnership; Big Sky is Big Sky Regional Carbon Sequestration Partnership; PCOR is Plains CO_2 Reduction Partnership.

Issues for Congress

In March 2007, the Massachusetts Institute of Technology (MIT) released a report called *The Future of Coal*, which concluded that CCS "is the critical enabling technology that would reduce CO_2 emissions significantly while also allowing coal to meet the world's pressing energy needs."[62] The report's conclusion assumes that a future, "carbon-constrained" world includes some level of a carbon charge, or a price on CO_2 emissions. The United States is not yet in a carbon-constrained world and, in the absence of a price on CO_2 and an economic incentive to invest in CCS, technological advancement and commercial deployment of CCS may depend, at least initially, on federal support. At issue for Congress is whether the current DOE carbon sequestration R&D program is appropriate in its emphasis and funding, and whether other agencies should be involved in carbon sequestration research as well.

A number of bills introduced in the 110th Congress would alter the DOE program and would engage at least one other agency, the U.S. Geological Survey within the Department of the Interior, in assessing the national capacity to geologically store $CO_{2.}$ Both the House and Senate have passed bills — H.R. 3221 and H.R. 6, respectively — that would authorize levels of funding for CCS R&D that double or triple the current DOE spending over the next five to six years. Each bill also gives the USGS prime responsibility for producing a methodology for and conducting a national survey of the U.S. carbon sequestration potential. DOE officials have acknowledged that more funding would help accelerate their timeline for conducting large-volume CO_2 injection tests across the United States. Whether Congress will pass carbon sequestration legislation and appropriate the funds to match spending levels in H.R. 6 or H.R. 3221 remain open questions.

It is widely recognized that costs for CO_2 capture and compression, either pre- or post-combustion, will dominate the overall costs of CCS, and that reducing those costs will be imperative to widespread deployment of CCS technologies. The premise of a carbon-constrained world, and the projected costs of carbon sequestration, is influencing decisions made today about future fossil-fueled power plants. For example, in 2007 a judge in a Minnesota public utility hearing recommended against purchasing power from a proposed power plant, citing the high cost estimates of CCS, which could double the cost of energy compared to an older non-CCS plant, as a reason to reject the proposal.[63] Thus, even without a price for CO_2 emissions, or a mandatory cap, the private sector is faced with a regulatory and

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[62] John Deutch, Ernest J. Moniz, et al., *The Future of Coal*, Cambridge, MA: Massachusetts Institute of Technology (2007).

[63] Rebecca Smith, "Coal's Doubters Block New Wave of Power Plants," *Wall Street Journal* (July 25, 2007).

permitting environment that *anticipates* such requirements and is beginning to include the potential cost of CCS into its decision-making process.

Paradoxically, and despite U.S. emissions of over 2 $GtCO_2$ per year from electricity generation alone, large-volume geologic sequestration tests of 1 $MtCO_2$ per year may have difficulty finding sufficient and inexpensive quantities of CO_2 to inject underground. The difficulty ties back to the costs, and technological barriers, of separating large volumes of CO_2 from the flue streams of the hundreds of currently operating coal-fired plants that hypothetically could furnish CO_2 for the tests. Congress may consider whether the U.S. carbon sequestration program is on track to develop the technology that efficiently captures CO_2 so that the costs of supplying sufficient CO_2 for large-volume sequestration tests across the country are not prohibitive.

Other issues that Congress may consider for large-scale CCS deployment are not discussed in this report. Liability and long-term ownership for CO_2 sequestered underground are two examples, especially as the treatment of CO_2 transitions from a commodity — as it is considered in EOR — to a pollutant, as the Supreme Court has ruled in one case.[64] Congress may also wish to consider the economic impacts of a broad CCS infrastructure that could require large quantities of CO_2 pipeline and could raise issues of rights-of-way and safety. Infrastructure may be especially important for areas of the country that lack geologic sequestration potential, such as New England and the Carolinas. In those cases, other types of sequestration strategies, such as deep-ocean disposal of CO_2, may become more attractive where otherwise long and expensive pipeline networks would be required to transport CO_2 from source to geologic reservoirs.

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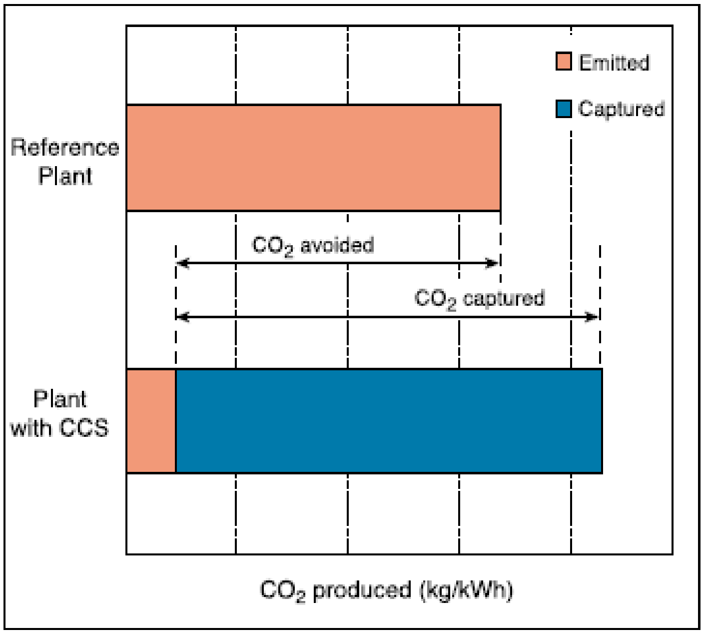
[64] *Massachusetts vs. EPA*; at [http://www.supremecourtus.gov/opinions/06pdf/05-1120.pdf].

Appendix A. Avoided CO_2

Figure 3 compares captured CO_2 and avoided CO_2 emissions. Additional energy required for capture, transport, and storage of CO_2 results in additional CO_2 production from a plant with CCS. The lower bar in **Figure 3** shows the larger amount of CO_2 produced per unit of power (kWh) relative to the reference plant (upper bar) without CCS. Unless no additional energy is required to capture, transport, and store CO_2, the amount of CO_2 avoided is always less than the amount of CO_2 captured. Thus the cost per tCO_2 avoided is always more than the cost per tCO_2 captured.[65]

Figure 3. Avoided Versus Captured CO_2



Source: IPCC Special Report, Figure 8.2.

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[65] IPCC Special Report, p. 346-347.