7. Pursue Carbon Capture and Utilization or Sequestration

Carbon capture and utilization and/or storage refers to a two-pronged approach to reducing carbon dioxide (CO_2) emissions from fossil-fired electric generating units (EGUs) and other CO_2-emitting facilities. At EGUs, CO_2 can be collected prior to or after combustion of fuel using one of three types of capture: pre-combustion, oxy-combustion, or post-combustion. Following *capture*, the CO_2 can be compressed and transported to an injection site for underground *storage,* or it can be *utilized* for productive purposes.

CO_2 is primarily considered a waste product, but there are a limited number of exceptions in which it can be used for productive purposes. These exceptions include using CO_2 for enhanced oil recovery (EOR); producing consumer products like carbonated beverages; and growing algae that can be used for biofuels, animal feed, or chemical production.[1] Of these options, EOR is the most technologically mature and has the most working examples demonstrating its feasibility for widespread use. The demand for CO_2 in consumer products, on the other hand, is currently very limited and in most cases the gas would eventually be emitted as the product is used or consumed. Using CO_2 to grow algae is a promising option that is the subject of numerous demonstration projects but is not yet commercially deployed at full scale. Therefore, this chapter focuses primarily on the combination of carbon capture with underground storage or with EOR.

Pre-combustion capture is a technology applicable to Brayton cycle[2] facilities including integrated gasification combined-cycle (IGCC) plants. IGCC plants gasify solid fuels such as coal and petroleum coke[3] to produce "synthesis" gas or "syngas," a combustible fuel whose main constituents are hydrogen, carbon monoxide (CO), and CO_2. Carbon capture removes the latter two components of syngas, leaving primarily hydrogen to be burned for electricity production.

As shown in Figure 7-1, following gasification and gas cleanup in the particle remover, syngas is sent to a shift reactor that "shifts" CO to CO_2, hence the need for steam at this step to add the additional oxygen atom and create CO_2 out of CO. Next, the sulfur content in syngas, in particular hydrogen sulfide or acid gas, must be removed.[4] Finally, the CO_2 can be separated from the syngas and then compressed for transport and storage.

Oxy-combustion capture creates a highly concentrated stream of CO_2 by firing fuel in an oxygen-rich environment.

1 For more information regarding the use of CO_2 to grow algae, refer generally to the Algae Biomass Organization website at: http://www.algaebiomass.org/. A summary of demonstration projects is available at: http://www.algaebiomass.org/wp-content/uploads/2010/06/ABO_project_book_lo-res_July2013.pdf.

2 The Brayton cycle (or Joule cycle) represents the operation of a gas turbine engine. The cycle consists of four processes: compression of an inlet stream (air); constant pressure fuel combustion; expansion and exhaust through a turbine and/or exhaust nozzle, turning a generator (and also driving the compressor); and cooling the air back to its initial condition. See: http://web.mit.edu/16.unified/www/SPRING/propulsion/notes/node27.html

3 Petroleum coke is a byproduct of oil refining.

4 Figure 7-1 shows gypsum as the byproduct of sulfur removal, but in order to recover gypsum from an IGCC plant a hydrogen sulfide furnace and limestone-gypsum absorber are necessary. Onishi, H. (2004, September). *250 MW Air-Blown IGCC Demonstration Plant in Japan and its Future Prospect.* 19th World Energy Congress.

Figure 7-1

Pre-Combustion Capture at an IGCC Plant[5]

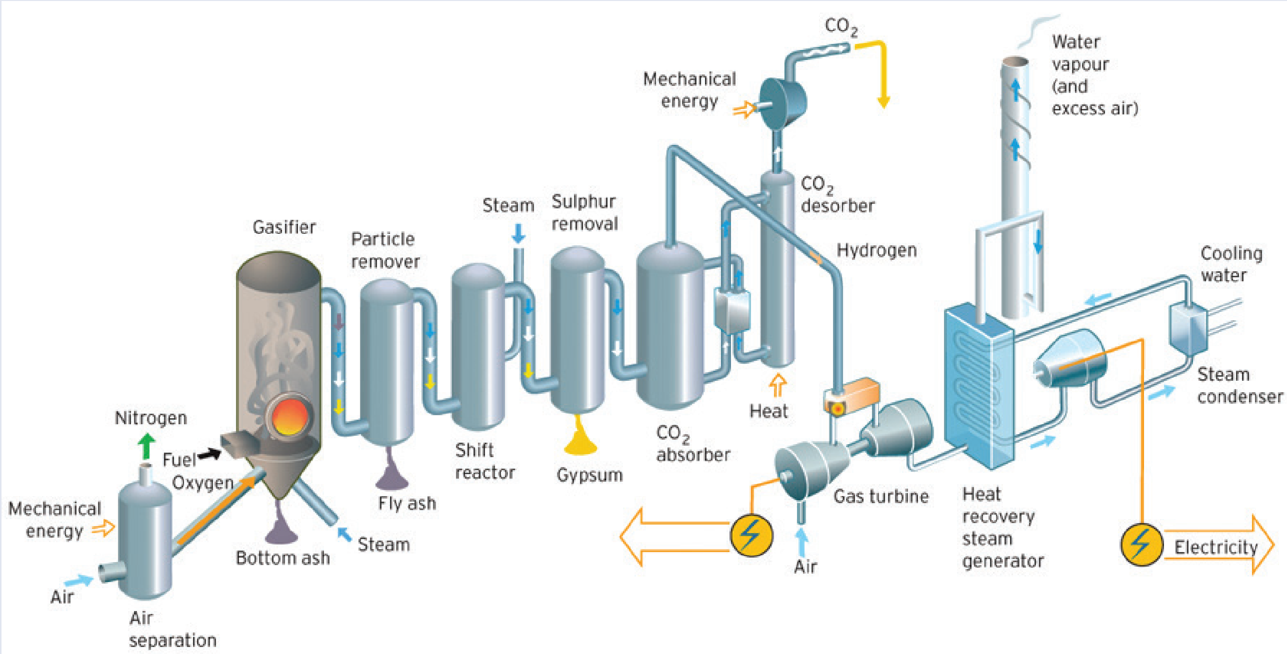
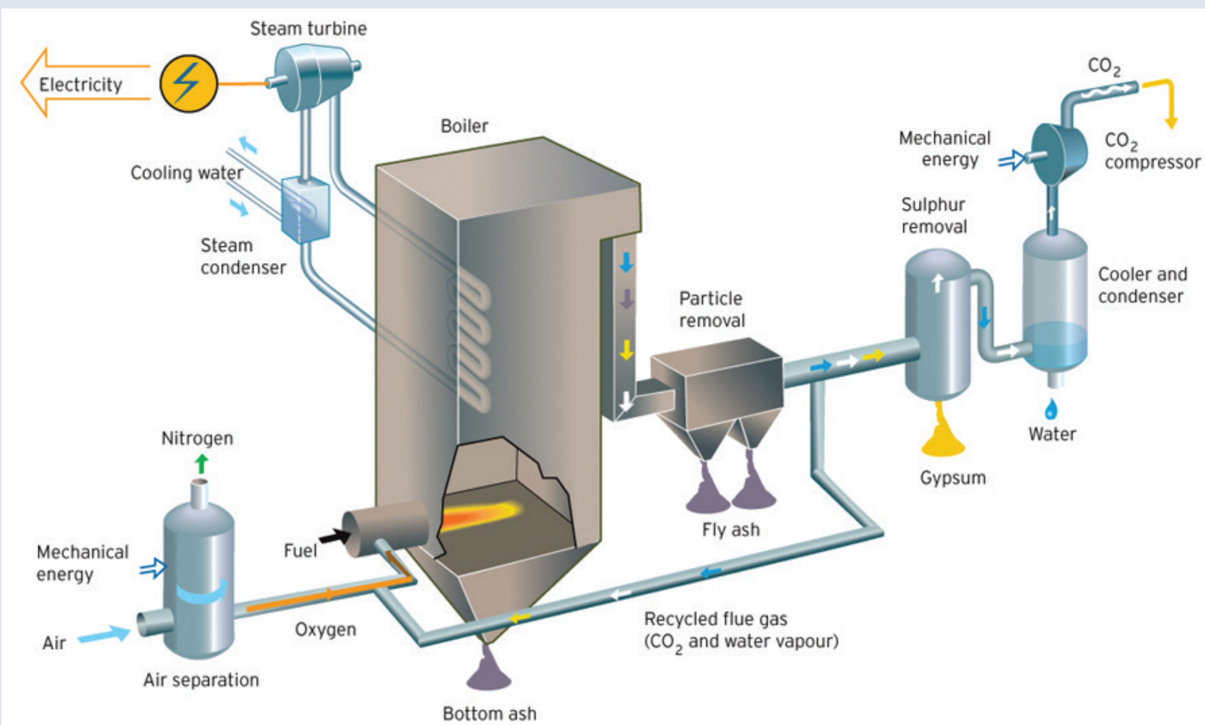


Figure 7-2

Oxy-Combustion Capture at a Pulverized Coal Plant[6]

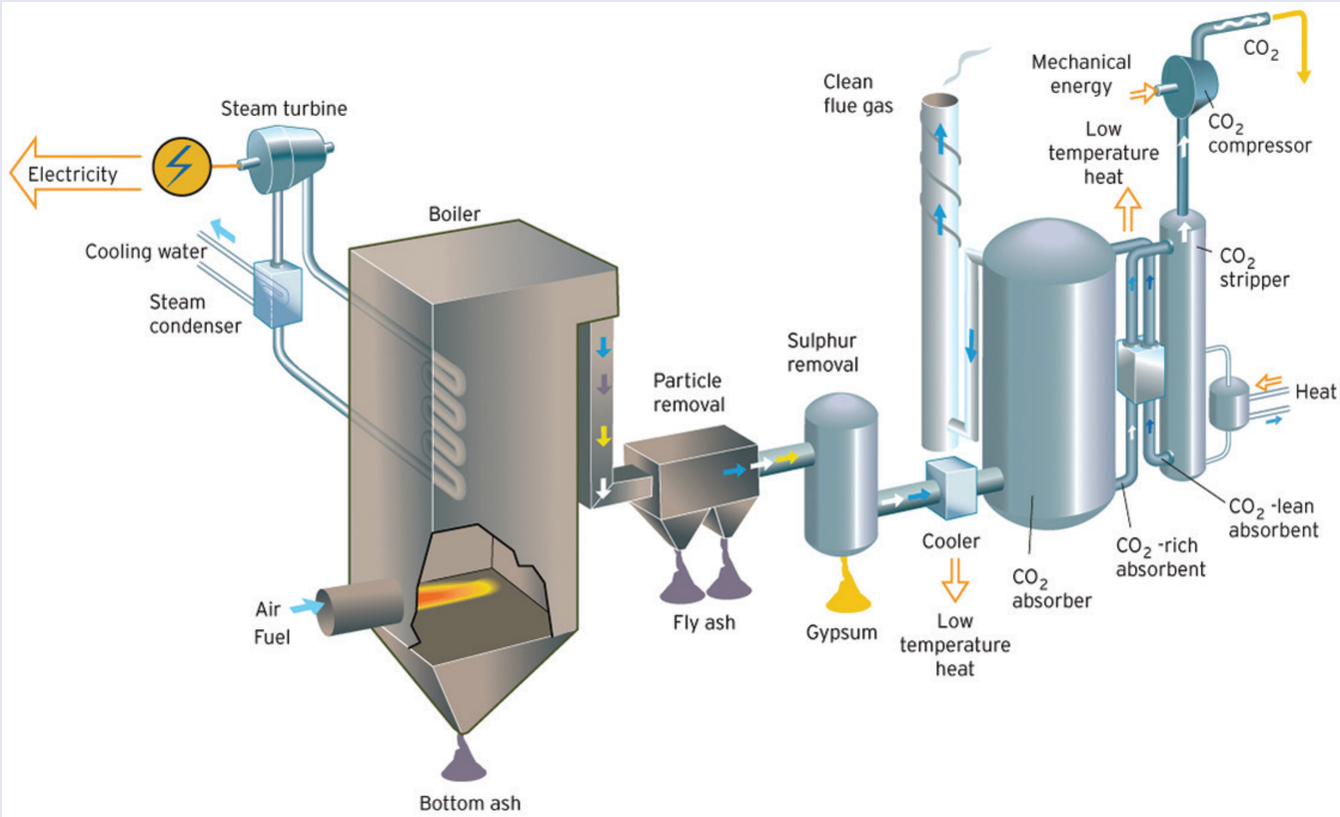


5 Vattenfall. (2012, December). *Illustrations*. Available at: http://www.captureready.com/userfiles/image/Carbon%20Capture/Pre-combustion%20Capture%20Process_Vattenfall.jpg

6 Vattenfall. (2012, December). *Illustrations*. Available at: http://www.captureready.com/userfiles/image/Carbon%20Capture/Oxyfuel%20Combustion%20Capture%20Process_Vattenfall.jpg

Figure 7-3

Post-Combustion Capture at a Pulverized Coal Plant[7]



The resulting flue gas is approximately 70 percent CO_2.

As shown in Figure 7-2, ash and sulfur emissions must be removed, as in typical pulverized coal plant operations. In addition, the water content of the flue gas must be reduced before the CO_2 is ultimately compressed for transport.

Because of the expense associated with oxy-combustion (discussed in Section 6) and because there are only three operating IGCC plants in the United States,[8] the focus of most of this chapter is on carbon storage coupled with post-combustion capture. Post-combustion capture is typically envisioned on pulverized coal plants, as shown in Figure 7-3, but could also occur on the back end of natural gas-fired power plants.

Post-combustion capture strips the flue gas of its CO_2 using ammonia or an amine as the absorbent and then compresses the CO_2 for transport and storage. The maximum percentage of CO_2 that can be captured by any of these technologies is 90 percent. But regardless of how the CO_2 is captured, it must be compressed to its supercritical phase for transport. In its supercritical state, the CO_2 has properties of both a gas and a liquid.

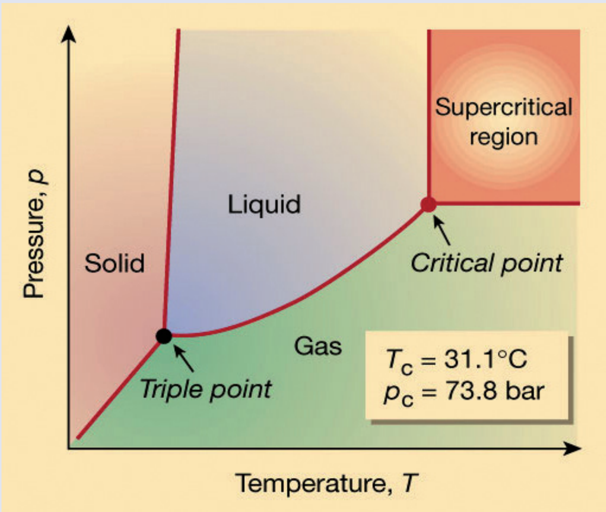
To reach its supercritical phase, the CO_2 is compressed in multiple stages. The minimum temperature and pressure at which CO_2 reaches its supercritical state are 31.1 degrees Celsius and 73.8 bar as shown in Figure 7-4. Compression to this phase is necessary to transport large volumes of CO_2, and also to inject the CO_2. Much more underground

7 Vattenfall. (2012, December). *Illustrations.* Available at: http://www.captureready.com/userfiles/image/Carbon%20Capture/Post-combustion%20Capture%20Process_Vattenfall.jpg

8 The operating IGCC plants are Wabash River and Edwardsport in Indiana and Polk Power in Florida. The Kemper County IGCC plant is under construction in Mississippi. The Texas Clean Energy Project, a coal-fired IGCC plant, and the Hydrogen Energy California Project, a petroleum coke-fired IGCC plant, are also in the planning stages but not yet under construction.

Figure 7-4

CO_2 Phase Diagram[9]



volume is needed to store CO_2 in the gas phase than in the supercritical phase.[10]

There are three main types of geologic formations thought to provide sufficient capacity to store large volumes of CO_2: saline aquifers, oil and gas reservoirs, and unmineable coal seams. Saline aquifers consist of layers of sedimentary porous and permeable rocks saturated with salty water, called brine.[11] Saline aquifers are thought to have the largest potential for carbon storage because they are so widespread.

Oil and gas reservoirs are less plentiful than saline aquifers, but they are generally better understood owing to years of oil and gas production. These reservoirs may be used purely for sequestration, but often they are used for EOR as well. In EOR, CO_2 is injected into a reservoir to stimulate oil production. Because CO_2 is miscible[12] with oil, it makes the oil more fluid and pushes it toward the producing well.[13] CO_2-EOR can produce approximately 35 percent of the residual oil in a reservoir.[14]

Coal seams may be considered unmineable for geologic, economic, or other reasons. Coal seams have less potential storage capacity than saline aquifers or oil and gas reservoirs, but they do have the possible co-benefit of enhancing methane production while trapping CO_2. Methane is the primary consituent of natural gas. Coal and methane are often found together; methane resides on the surface of the coal, a phenomenon known as adsorption.[15] However, because coal preferentially adsorbs CO_2 over methane, the coal releases the methane for production from the seam when CO_2 is present.

Whether storage in a saline aquifer, hydrocarbon reservoir, or coal seam is contemplated, characterization of the formation is extremely important. Among the characteristics that must be determined are *porosity* and *permeability.* Porosity is the "percentage of pore volume or void space… that can contain fluids."[16] Permeability is "the ability, or measurement of a rock's ability, to transmit fluids [measured in darcys[17]]."[18] A permeable formation typically has many large pores that are well connected.[19] Porosity and permeability help determine another very important aspect of any storage formation, *injectivity.* Injectivity is "the rate and pressure at which fluids can be pumped into the treatment target without fracturing the formation."[20] Although fractures

9 Leitner, W. (2000, May 11). Green Chemistry: Designed to Dissolve. *Nature 405,* 129–130. Available at: http://www.nature.com/nature/journal/v405/n6783/fig_tab/405129a0_F1.html

10 US Department of Energy National Energy Technology Laboratory. (2010, September). *Geologic Storage Formation Classifications: Understanding Its Importance and Impacts on CCS Opportunities in the United States,* p. 11. Available at: www.netl.doe.gov/File%20Library/Research/Carbon-Storage/Project-Portfolio/BPM_GeologicStorageClassification.pdf

11 US Department of Energy National Energy Technology Laboratory. (2012). *Carbon Utilization and Storage Atlas.* Available at: http://www.netl.doe.gov/research/coal/carbon-storage/atlasiv

12 A "miscible" fluid can be mixed with other fluids to form a homogenous solution.

13 Hyne, N. (2001). *Nontechnical Guide to Petroleum Geology, Exploration, Drilling, and Production.* Tulsa, OK: PennWell.

14 Supra footnote 13

15 Nazaroff, W., & Alvarez-Cohen, L. (2001). *Environmental Engineering Science.* New York: Wiley.

16 Schlumberger. (2011). *Porosity.* Entry in oilfield glossary available at: http://www.glossary.oilfield.slb.com/en/Terms/p/porosity.aspx

17 A rock formation with a permeability of 1 darcy permits a flow of 1 cm^3/second of a fluid with viscosity of 1 under a pressure gradient of 1 atmosphere/cm acting across an area of 1 cm^2.

18 Schlumberger. (2011). *Permeability.* Entry in oilfield glossary available at: http://www.glossary.oilfield.slb.com/en/Terms/p/permeability.aspx

19 Ibid.

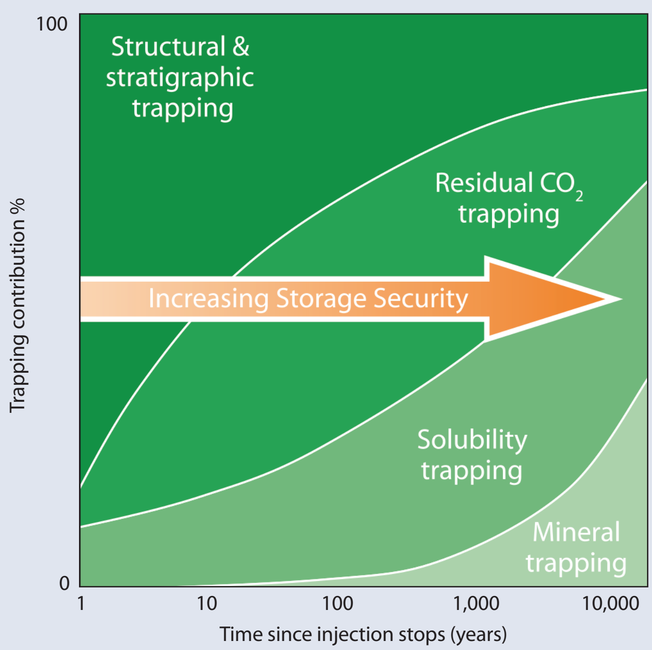
20 Schlumberger. (2011). *Injectivity Test.* Entry in oilfield glossary available at: http://www.glossary.oilfield.slb.com/Display.cfm?Term=injectivity%20test

in a storage formation would seem to offer additional pathways for the CO_2 to move, they can also provide pathways for the CO_2 to escape to the surface and thereby compromise the integrity of the storage formation.

When CO_2 is injected underground, several mechanisms may work to keep it underground. First, because the other fluids in saline aquifers and oil and gas reservoirs are less buoyant than CO_2, a low permeability seal or caprock is necessary to prevent CO_2 from migrating upward.[21] This is known as "primary" or "buoyant" trapping.[22] "Secondary" trapping mechanisms include: dissolving CO_2 in water (solubility trapping); trapping CO_2 by capillary forces between pore spaces (residual trapping); precipitation of CO_2 in a carbonate compound (mineral trapping); and trapping CO_2 in coal seams (adsorption trapping, discussed previously).

Figure 7-5

Trapping Mechanisms Occur on Different Time Frames[23]



Each trapping mechanism happens on a different time scale (Figure 7-5).

Primary trapping (also known as "structural" or "stratigraphic" trapping) occurs immediately, but residual trapping is thought to happen after injection stops.[24] Mineral trapping, in particular, is believed to occur on much longer time frames.

In 2012, the United States Geological Survey (USGS) published its estimate of the technical CO_2 geologic storage potential in the United States. USGS's assessment of the CO_2 storage resource was conducted using "present-day geological and engineering knowledge and technology for CO_2 injection into geologic formations."[25] It did not incorporate economic or engineering constraints.

The areas analyzed by the USGS are shown in the map in Figure 7-6. The lighter grey areas were evaluated by the USGS but were not assessed. The resulting storage estimates predicted that the most storage capacity lies in the Coastal Plains (1900 gigaton [Gt]), followed by the Rocky Mountains and Northern Great Plains and Alaska (270 Gt each), and the Eastern Mid-Continent (230 Gt). All other regions were estimated to have 150 Gt or less of storage potential, for a total mean storage potential of 3000 Gt. The USGS's assessment included saline aquifers and oil and gas reservoirs, but not unmineable coal seams because the USGS could find no definition to determine which coals seams are unmineable.[26]

The USGS's methodology accounted for two trapping mechanisms: buoyant and residual. The residual trapping resource was divided into three classes based on reservoir permeability: class 1 (formations with permeability greater than 1 darcy [D]); class 2 (formations with permeability between 1 millidarcy [mD] and 1 D); and class 3 (formations with permeability of less than 1 mD).

21 Benson, S. M., & Cole, D. R. (2008). CO_2 Sequestration in Deep Sedimentary Formations. *Elements 4(5),* 325–331. doi: 10.2113/gselements.4.5.325 Available at: http://elements.geoscienceworld.org/content/4/5/325.short

22 Supra footnote 11.

23 Metz, B., Davidson, O., de Coninck, H., Loos, M., & Meyer, L., eds. (2005). *Carbon Dioxide Capture and Storage.* Prepared by Working Group III of the Intergovernmental Panel on Climate Change. Cambrige, United Kingdom: Cambridge University Press, pp. 195–276. Available at: http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf

24 Supra footnote 21.

25 Brennan, S. T., Burruss, R. C., Merrill, M., D.; Freeman, P. A., & Ruppert, L. F. (2010). *A Probabilistic Assessment Methodology for the Evaluation of Geologic Carbon Dioxide Storage.* USGS Open-File Report 2010–1127. Available at: http://pubs.usgs.gov/of/2010/1127

26 US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team. (2013). *National Assessment of Geologic Carbon Dioxide Storage Resources—Results.* US Geological Survey Circular 1386. Available at: http://pubs.usgs.gov/circ/1386/

Figure 7-6

Eight Regions Used in USGS's Geologic Storage Resource Assessment[27]

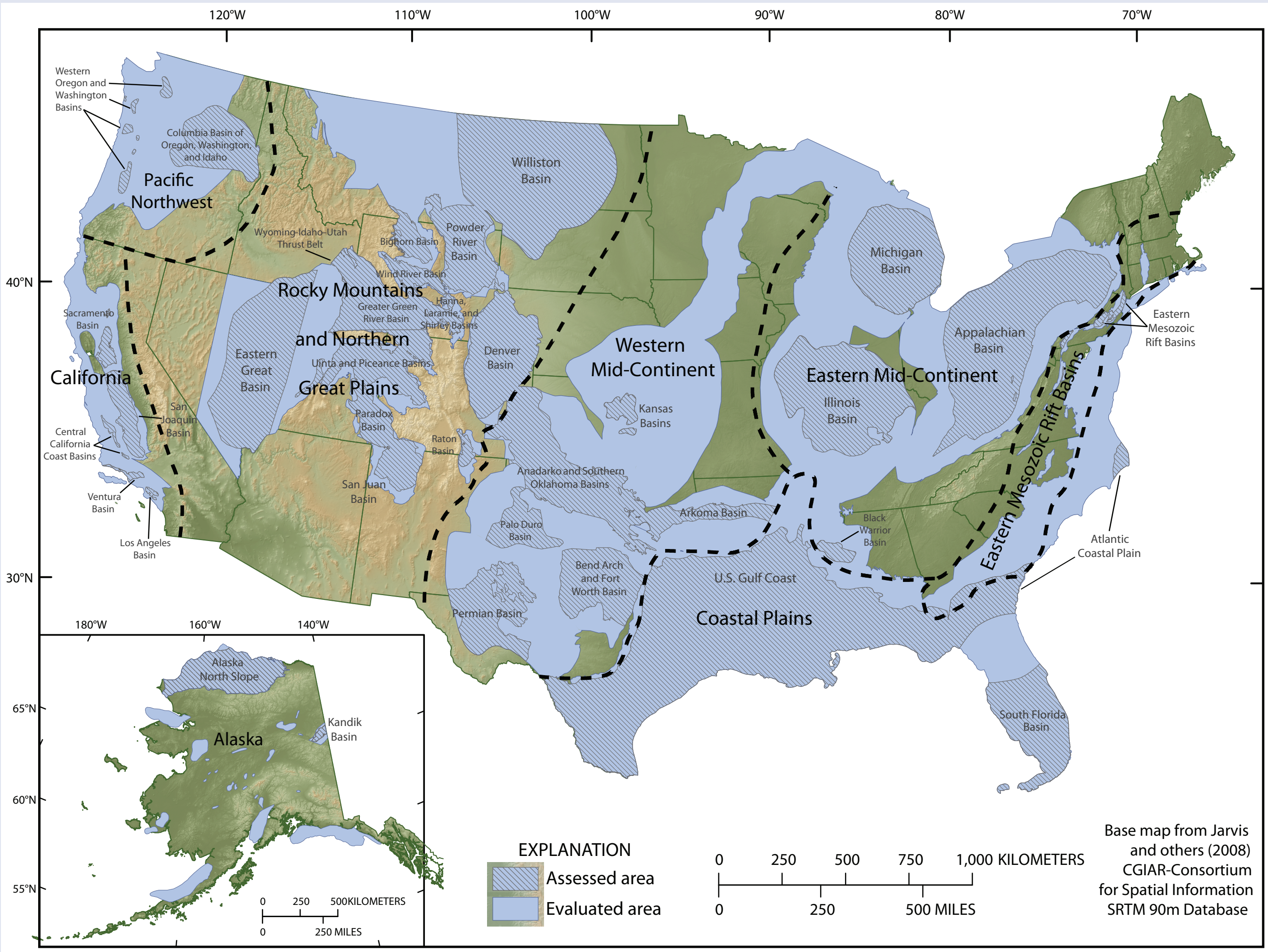
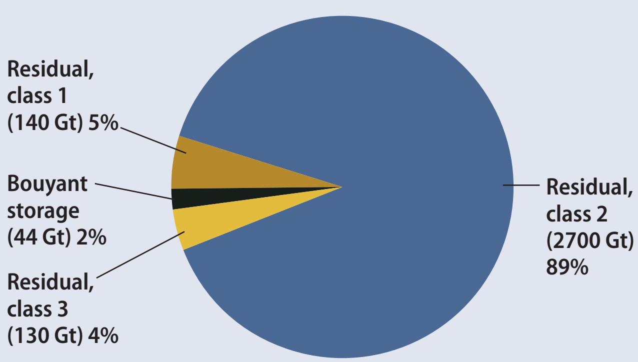


Figure 7-7

Geologic Storage Resource by Trapping Mechanism and Permeability Class[28]



The USGS found residual trapping in class 2 formations to be the overwhelming driver of total nationwide storage capacity, accounting for 89 percent of the resource (Figure 7-7).

Figure 7-8 depicts a sample cross-section of a storage formation such as those the USGS analyzed in this assessment.

The blue areas show the parts of the formation where buoyant trapping occurs. The green depicts the areas where residual trapping would have to be relied upon. Simply from a visual perspective, it's clear that residual trapping dramatically increases the volume available for CO_2 storage.

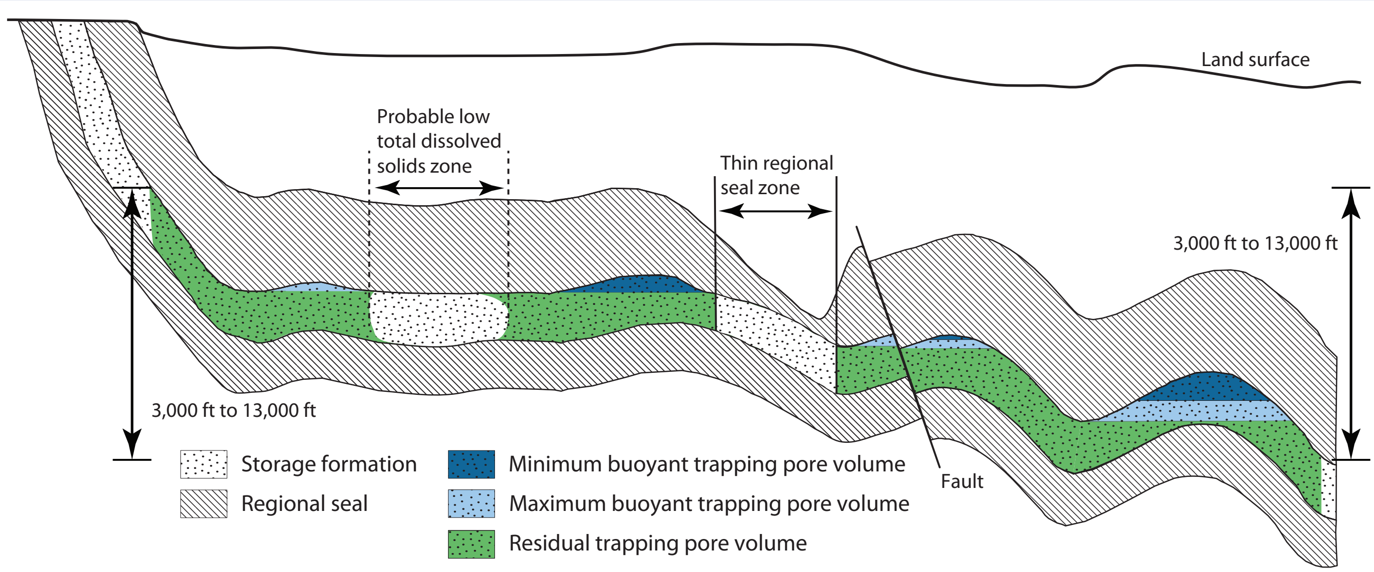
It is important to note, therefore, that "storage efficiencies

27 Supra footnote 26.

28 Ibid.

Figure 7-8

Cross-Section of a Sample Storage Formation Showing the Distribution of Pore Volume Between Buoyant and Residual Trapping[29]



associated with residual trapping are poorly understood," because no commercial-scale injection projects using this trapping mechanism have been undertaken.[30] In 2013, the United States emitted approximately 5.4 Gt of energy-related CO_2.[31] If carbon storage is to play a major role in addressing climate change, then secondary trapping mechanisms must be dependable. Relying on buoyant trapping alone would only provide enough capacity to store eight years' worth of the nation's CO_2 emissions.

2. Regulatory Backdrop

In the United States, no state or federal law has mandated the application of carbon capture and sequestration (CCS) to any power plant. However, partial CCS was proposed by the US Environmental Protection Agency (EPA) to be the Best System of Emission Reduction for new utility boilers and IGCC units under the agency's proposed carbon pollution standards for these sources (a.k.a. the proposed "111(b) rule," because it is based on the EPA's authority under section 111(b) of the Clean Air Act). The EPA defined partial CCS as achieving a CO_2 emissions rate of 1100 pounds per gross megawatt-hour (MWh). A new source would likely use a continuous emissions monitoring system to measure the plant's mass CO_2 emissions and demonstrate compliance. With respect to *existing* power plants and the Clean Power Plan that the EPA proposed in June 2014, the EPA determined that CCS is *not* an adequately demonstrated and cost-effective measure for reducing CO_2 emissions on a national scale:

> While the EPA found that partial CCS is technically feasible for new fossil fuel-fired boilers and IGCC units, it is much more difficult to make that determination for the entire fleet of existing fossil fuel-fired EGUs. Developers of new generating facilities can select a physical location that is more amenable to CCS – such as a site that is near an existing CO_2 pipeline or an existing oil field. Existing sources do not have the advantage of pre-selecting an appropriate location. Some existing facilities are located in areas where CO_2 storage is not geologically favorable and are not near an existing CO_2 pipeline. Developers of new facilities also have the advantage of integrating the partial

29 Blondes, M., Brennan, S., Merrill, M., Buursink, M., Warwick, P., Cahan, S., Cook, T., Corum, M., Craddock, W., DeVera, C., Drake II, R., Drew, L., Freeman, P., Lohr, C., Olea, R., Roberts-Ashby, T., Slucher, E., & Varela, B. (2013). *National Assessment of Geologic Carbon Dioxide Storage Resources—Methodology Implementation.* US Geological Survey Open-File Report 2013–1055. Available at: http://pubs.usgs.gov/of/2013/1055/

30 Supra footnote 25.

31 US Energy Information Administration. (2014, June). *Monthly Energy Review.* Available at: http://www.eia.gov/totalenergy/data/monthly/archive/00351406.pdf

CCS system into the original design of the new facility. Integrating a retrofit CCS system into an existing facility is much more challenging. Some existing sources have a limited footprint and may not have the land available to add partial CCS system. Integration of the existing steam system with a retrofit CCS system can be particularly challenging.[32]

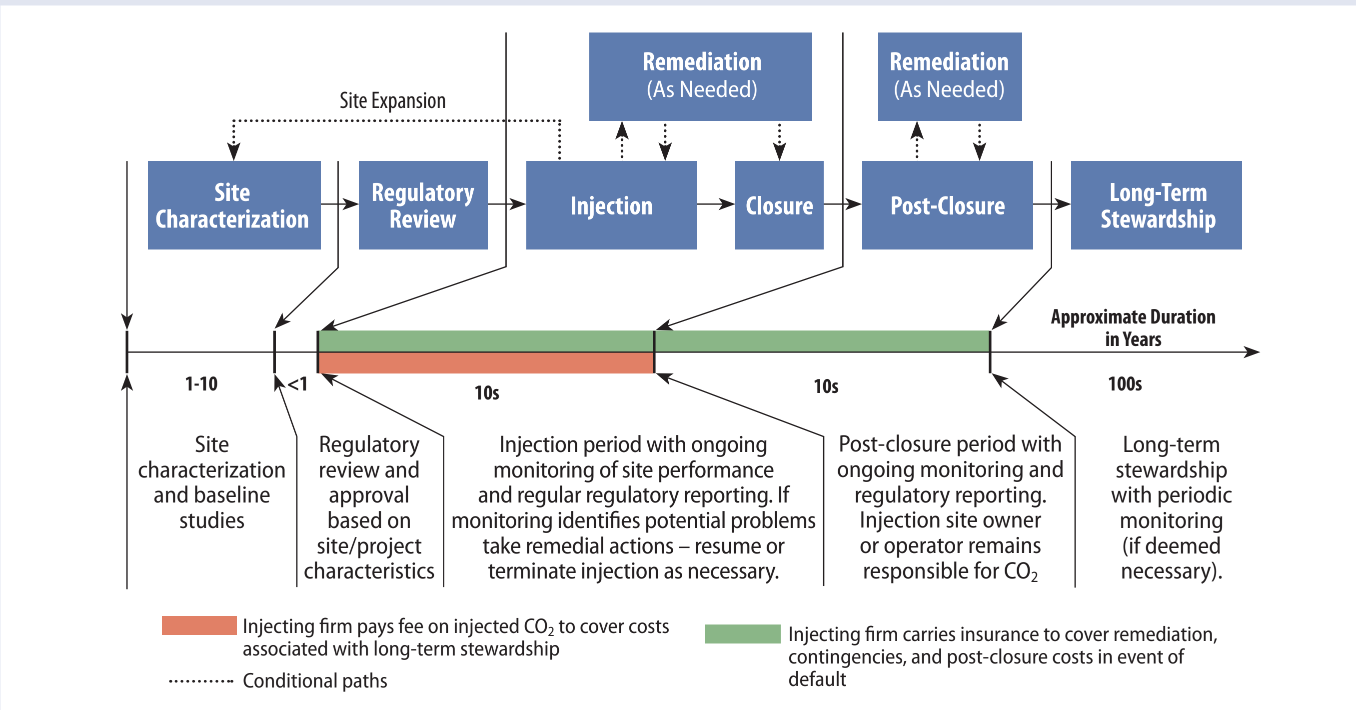
Although the EPA decided not to include CCS as part of the Best System of Emission Reduction for existing power plants, the agency notes that "at some existing facilities, the implementation of partial CCS may be a viable greenhouse gas (GHG) mitigation option and some utilities may choose to pursue that option" for complying with the 111(d) rule.[33] No specific mechanism for measuring the impact of CCS at existing facilities was included in the EPA's proposal, but all affected EGUs would be equipped with CO_2 continuous emissions monitoring systems. With respect to both the 111(b) and 111(d) proposals, the EPA appears to have based its findings about the viability of CCS on a review of geologic storage and EOR technical potential, without consideration of other potential utilization options, such as growing algae for biofuels.

It is worth noting that geologic storage of CO_2 is a fairly new field for regulation. Among the steps in carbon storage that need to be addressed through regulation are site characterization, site operations, closure, and long-term stewardship.[34]

As Figure 7-9 shows, each of these steps is likely to be

Figure 7-9

Phases of a Geologic Storage Project[35]



32 US EPA. (2014, June). *GHG Abatement Measures – Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units.* Docket ID No. EPA-HQ-OAR-2013-0602. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-ghg-abatement-measures

33 Ibid.

34 Wilson, E., & Pollak, M. (2008). *Policy Brief: Regulation of Carbon Capture and Storage.* International Risk Governance Council. Available at: http://www.hhh.umn.edu/people/ewilson/pdf/regulation_carbon_capture_storage.pdf

35 Rubin, E. S., Morgan, M. G., McCoy, S. T., & Apt., J. (2007, May). *Regulatory and Policy Needs for Geological Sequestration of Carbon Dioxide.* Proceedings of US Department of Energy 6th Annual Conference on Carbon Capture and Sequestration. Available at: http://www.epp.cmu.edu/people/faculty/rubin/index.php?p=2007

multiyear. Site characterization is the process of identifying a potential site and confirming that it is suitable for carbon storage. The steps involved have been defined more conceptually than in terms of specific characteristics or analytical methodologies, owing to the lack of experience with carbon storage.[36] Regulation of injection would address such contingencies as release to the atmosphere, surface damage, and CO_2 migration beyond the intended storage formation.[37] The transition from post-closure to long-term stewardship is largely defined by who holds the responsibility to ensure that the injected CO_2 is retained in the storage formation. The authors of Figure 7-9 assume that long-term stewardship, which could last hundreds of years, will ultimately be taken over by the federal government because they "do not believe that there is any feasible way to assign long-term stewardship responsibility in perpetuity to any private entity, nor would private actors accept such responsibility."[38]

Missing from Figure 7-9 is the need for rules governing the ownership of pore space in the subsurface. Although surface property rights and subsurface mineral rights have been separable for many years in several areas of the United States, there is no clear precedent as to whether pore space rights belong to the surface owner, subsurface mineral rights owner, or neither.[39] Because CO_2 storage may interact with other subsurface activities such as produced water disposal, water recovery, hydrocarbon production, or natural gas storage,[40] resolving the question of who has access to pore space is important to the success of CCS projects.

To date, there are federal regulations governing injection, to a degree, but not other aspects of storage.

On July 25, 2011, the EPA finalized a rule establishing a permitting system for wells used in the geologic storage of CO_2.[41] The Federal Underground Injection Control (UIC) Class VI Program for Carbon Dioxide Geologic Sequestration will allow states and potential owners/operators of wells used in geologic storage to receive a permit from the appropriate EPA regional office. The federal government has primacy over this program until a state applicant submits and has its application approved by the EPA.[42] Thus far only North Dakota has submitted an application for primacy.[43]

The UIC program, however, was established under the Safe Drinking Water Act and, as such, it is aimed at preventing drinking water contamination, not at ensuring long-term storage of CO_2.[44] In addition, the UIC program does not cover injection in offshore formations.[45]

The CCSReg Project, a group of academics and lawyers exploring how to "best…implement an appropriate regulatory environment in the US for the commercialization of carbon capture and deep geological sequestration," has called for federal legislation to accomplish the following:

- Declare that sequestering CO_2 in geologic formations to mitigate the detrimental effects of climate change is in the public interest;
- Address the issue of access to and use of geologic pore space;
- Amend the Safe Drinking Water Act to direct UIC regulators to promulgate rules for geologic sequestration (GS) that:

36 Rodosta, T. D., Litynski, J. T., Plasynski, S. I., Hickman, S., Frailey, S., & Myer, L. (2011). US Department of Energy's Site Screening, Site Selection, and Initial Characterization for Storage of CO_2 in Deep Geological Formations. *Energy Procedia 4,* pp. 4664–4671. Available at: http://www.sciencedirect.com/science/article/pii/S1876610211007065

37 Supra footnote 35.

38 Ibid.

39 Wilson, E., & Klass, A. (2009, April). *Climate Change, Carbon Sequestration, and Property Rights.* University of Illinois Law Review, Vol. 2010, 2010 and Minnesota Legal Studies Research Paper No. 09-15. Available at: http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1371755

40 Ibid.

41 Refer to the Federal Register at: http://www.gpo.gov/fdsys/pkg/FR-2011-09-15/pdf/2011-23662.pdf

42 Ibid.

43 Refer to the Vinson & Elkins law firm website at: http://climatechange.velaw.com/EPAIssuesGuidanceSDWAClassVIPrimacyApplicants.aspx

44 Pollak, M., & Wilson, E. (2009). Regulating Geologic Sequestration in the United States: Early Rules Take Divergent Approaches. *Environmental Science & Technology, 43(9)*, pp. 3035–3041. Available at: http://pubs.acs.org/doi/abs/10.1021/es803094f

45 Supra footnote 35.

- Address all environmental, health, and safety issues associated with GS;
- Are principally based on adaptive, performance-based standards, as opposed to design standards; and,
- Include mechanisms to balance and resolve conflicts between multiple environmental objectives;

- Direct UIC regulators to coordinate with regulators in charge of GHG inventory accounting for the United States;
- Obligate GS project operators to contribute on the basis of their operating performance to a revolving fund to cover long-term stewardship; and
- Create an independent public entity (the Federal Geologic Sequestration Board) to approve and accept responsibility for appropriately closed GS sites.[46]

The CCSReg Project has also issued model legislation to cover these issues, but to date, Congress has taken no action. Meanwhile, several states have stepped in with legislation to address certain aspects of storage and transportation of CO_2.[47]

3. State and Local Implementation Experiences

In support of the proposed 111(b) GHG standards for new power plants, the EPA cited several examples of "currently operating or planned CO_2 capture or storage systems, including, in some cases, components necessary for coal-fired power plant CCS applications."[48] At the time the proposed rule was issued, there were no power plants in the United States or in the rest of the world that integrated commercial-scale CCS, but two carbon capture and EOR projects were under construction. One of them, the Boundary Dam Project in Saskatchewan, came online in October 2014 with an output of 110 MW. The project rebuilt an existing pulverized coal plant and retrofit it with a 90-percent post-combustion capture system at a cost of $1.35 billion.[49] The CO_2 captured at this facility is used in EOR at the Weyburn oil field.[50] The Kemper County IGCC project in Mississippi remains under construction, with commercial operation projected in mid 2016. It would capture approximately 65 percent of total CO_2 emissions and have a nominal output of 583 MW.[51] Kemper County has experienced schedule delays and cost increases that have pushed its in-service date into 2016 and raised the cost of the project to $5.5 billion. Kemper's captured CO_2 will be used for EOR in a Mississippi oil field.[52]

There are several other CO_2-emitting industrial facilities that capture and sequester CO_2 or use it in EOR. The Great Plains Synfuels Plant in North Dakota provides approximately 8700 tons per day of CO_2 for use in EOR at the Weyburn and Midale oil fields in Saskatchewan.[53] Great Plains Synfuels receives $20 per ton for its CO_2 and the project is expected to ultimately result in the storage of 20 million tons of CO_2.[54] The Sleipner gas processing facility in Norway had sequestered more than ten million tons of

46 Carnegie Mellon, Van Ness Feldman Attorneys at Law, Vermont Law School, & University of Minnesota. (2009, July). *Policy Brief: Comprehensive Regulation of Geologic Sequestration.* CCSReg Project. Available at: http://www.ccsreg.org/pdf/ComprehensiveReg_07202009.pdf

47 Refer to the CCSReg Project website at: http://www.ccsreg.org/billtable.php?component=Sequestration and http://www.ccsreg.org/billtable.php?component=Transportation.

48 US EPA. (2014, January 8). *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units; Proposed Rule,* pp. 1474–1475. Available at: http://www.gpo.gov/fdsys/pkg/FR-2014-01-08/pdf/2013-28668.pdf

49 Refer to the SaskPower website at: http://www.saskpowerccs.com/ccs-projects/boundary-dam-carbon-capture-project/carbon-capture-project/.

50 Massachusetts Institute of Technology. (2014, March). *Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/boundary_dam.html

51 Folger, P. (2014, February). *Carbon Capture and Sequestration: Research, Development, and Demonstration at the US Department of Energy.* Congressional Research Service Reports. Available at: http://fas.org/sgp/crs/misc/R42496.pdf

52 Massachusetts Institute of Technology. (2014, May). *Kemper County IGCC Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/kemper.html

53 Massachusetts Institute of Technology. (2013, December). *Weyburn-Midale Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/weyburn.html

54 Supra footnote 53.

CO_2 as of 2008.[55] Sleipner was designed specifically as a sequestration project in order to avoid paying Norway's carbon tax on CO_2 emissions. A second gas processing facility, In Salah in Algeria, injected about 3.8 million tons of CO_2 into a depleted gas reservoir for seven years before ceasing operations because of concerns about the integrity of the caprock.[56] More recently, an Archer Daniels Midland ethanol plant in Decatur, Illinois captured and sequestered 317,000 tons of CO_2 in its first year of operations.[57] The project is scheduled to continue through September 2015.[58]

In general, efforts in the United States to deploy carbon capture and/or storage are funded, at least in part, by the US Department of Energy (DOE). On the storage side, the DOE's Regional Carbon Sequestration Partnership supported seven regional partnerships pursuing a number of projects intended to ultimately sequester one million tons of CO_2 or more.[59] The Decatur, Illinois project discussed previously is one of these. And the Cranfield project in Mississippi had stored 4.7 million tons of mostly natural,[60] as opposed to anthropogenic, CO_2 by August 2013.[61]

A prominent piece of the DOE's investment in CCS research was the FutureGen project. Originally announced in 2003 and first conceived as an IGCC plant that would capture and sequester at least one million metric tons of CO_2 per year,[62] FutureGen was restructured in 2008 and then postponed because of rising costs.[63] In 2010, former Secretary of Energy Steven Chu announced a new version of the project, FutureGen 2.0, which would use $1 billion of American Recovery and Reinvestment Act money to retrofit an existing pulverized coal plant in Meredosia, Illinois with oxy-combustion capture and sequestration.[64] In February 2015, however, the DOE directed the suspension of FutureGen 2.0 project development activities because the project could not be completed prior to the expiration of American Recovery and Reinvestment Act funding in September 2015.[65]

4. GHG Emissions Reductions

There were more than 550 coal-fired power plants in the United States in 2012.[66] Some of those plants will retire before the proposed initial 111(d) compliance period begins in 2020. However, the majority are likely to still be operating and could be candidates for CCS.

55 Massachusetts Institute of Technology. (2014, January). *Sleipner Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/sleipner.html

56 Massachusetts Institute of Technology. (2014, January). *In Salah Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/in_salah.html

57 Massachusetts Institute of Technology. (2014, May). *Decatur Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/decatur.html

58 Ibid.

59 Supra footnote 11.

60 Southeast Regional Carbon Sequestration Partnership. (2007). *Factsheet for Partnership Field Validation Test: SECARB Phase III Tuscaloosa Formation CO_2 Storage Project.* Available at: http://www.netl.doe.gov/publications/proceedings/07/rcsp/factsheets/3-SECARB_Large%20Scale%20Saline%20Formation%20Demo.pdf

61 Massachusetts Institute of Technology. (2013, December). *Cranfield Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/cranfield.html

62 Government Accountability Office. (2009, February). *Clean Coal: DOE's Decision to Restructure FutureGen Should Be Based on a Comprehensive Analysis of Costs, Benefits, and Risks.* GAO-09-248. Available at: http://www.gao.gov/new.items/d09248.pdf

63 Folger, P. (2014, February). *The FutureGen Carbon Capture and Sequestration Project: A Brief History and Issues for Congress.* Congressional Research Service Reports. Available at: http://fas.org/sgp/crs/misc/R43028.pdf

64 Ibid.

65 Daniels, S. (2015, February 3). *FutureGen 'Clean-Coal' Plant is Dead.* Crain's Chicago Business. Available at: http://www.chicagobusiness.com/article/20150203/NEWS11/150209921/futuregen-clean-coal-plant-is-dead

66 Refer to the US Energy Information Administration website at: http://www.eia.gov/electricity/annual/html/epa_04_01.html.

Figure 7-10

Many Coal-Fired Power Plants Overlie Potential Storage Formations[67]

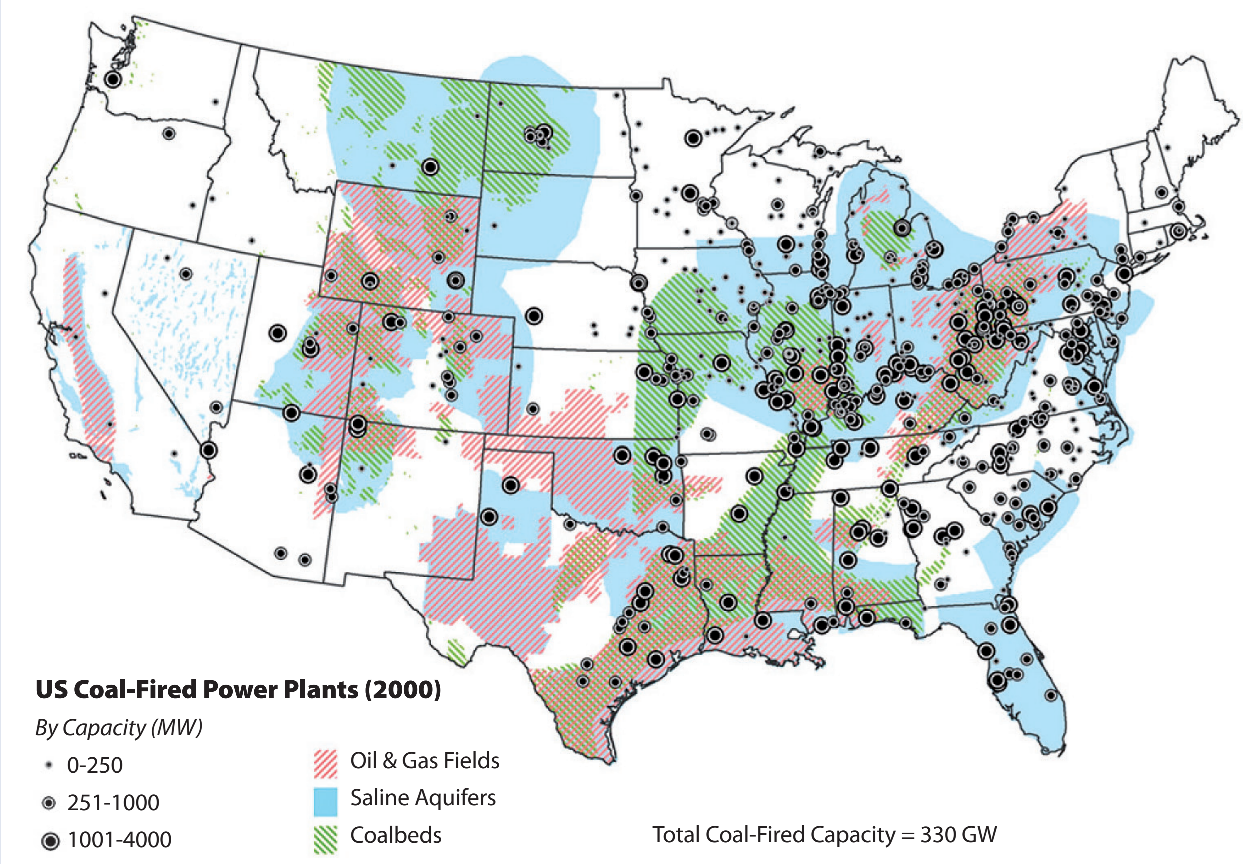


Table 7-1

Potential CO_2 Emissions Reductions per Year From CCS

CO_2 Emissions From Coal-Fired Power Plants in 2012[68] (million metric tons)	Potential Emissions Sequestered With 30% Capture (million metric tons)	Potential Emissions Sequestered With 60% Capture (million metric tons)	Potential Emissions Sequestered With 90% Capture (million metric tons)
1514	454	908	1363

Should large-scale deployment of CCS occur, not all those facilities would be retrofitted, but on the basis of location alone, few can be ruled out as candidates. Figure 7-10 shows the extent to which coal-fired power plants overlie saline aquifers, hydrocarbon reservoirs, and coal seams. This synergy is part of the reason that CCS may have large potential. Note, however, that no pipeline network connecting power plants to potential CO_2 storage formations currently exists. That infrastructure would need to be built in conjunction with any CCS retrofits.

Assuming all existing coal-fired power plants are retrofitted with CCS, the potential scale of sequestered emissions is estimated in Table 7-1.

Using the most recent emissions data from the year 2012, with 30 to 90 percent capture at all coal-fired power plants, a total of 454 to 1363 million metric tons of CO_2 could potentially be sequestered each year. Table 7-1 is akin to a simple technical potential estimate. It does not take into account the cost of sequestering this quantity of CO_2, nor the feasibility of doing so. And some subset of existing

67 Orr, F. (2009). CO_2 Capture and Storage: Are We Ready? *Energy & Environmental Science, 2,* pp. 449–458. Available at: http://pubs.rsc.org/en/Content/ArticleLanding/2009/EE/b822107n#!divAbstract

68 Refer to the US Energy Information Administration website at: http://www.eia.gov/tools/faqs/faq.cfm?id=77&t=11.

coal-fired power plants may simply be unable to retrofit because their sites cannot accommodate the footprint of a CCS system.

5. Co-Benefits

The primary co-benefit of CCS is that it would allow the United States to continue using a fuel (i.e., coal) that provides a large, although declining, share of the country's electricity even as we enter a carbon-constrained world.

There is relatively little information about CCS's other possible co-benefits such as employment and economic impacts. With regard to air emissions, applications of CCS at *new* pulverized coal plants would lower sulfur dioxide emissions as the proportion of carbon captured increases. However, nitrogen oxides, particulate matter, and mercury emissions would increase.[69] We would expect the same to be true of retrofit applications.

The full range of possible co-benefits associated with CCS is summarized in Table 7-2.

6. Costs and Cost-Effectiveness

The US Energy Information Administration (EIA) periodically produces estimates of the overnight capital costs of constructing new power plants with CCS as part of the modeling assumptions that are used in the *Annual Energy Outlook*. In the most recent data set, the EIA estimates that adding CCS to a typical, new, advanced pulverized-coal generating unit would increase the capital costs from $3246/kilowatt (kW) to $5227/kW. For an IGCC unit, the cost increases from $4400/kW to $6599/kW. And for an advanced natural-gas fired combined-cycle unit, the cost doubles from $1023/kW to $2095/kW.[70] The EIA also produces estimates of the levelized cost of energy for those plants. For an IGCC unit, the EIA estimates that CCS adds $31.5/MWh to the levelized cost of energy; for advanced natural-gas fired combined-cycle units, CCS increases costs by $26.9/MWh.[71]

Because of limited implementation experience, there is little information estimating the costs of retrofitting existing power plants with carbon capture. A 2014 presentation by the National Energy Technology Laboratory (NETL) predicted that retrofitting a pulverized coal plant with post-combustion capture would raise its cost of energy from $45 to $124 per MWh (2011$) and

Table 7-2

Types of Co-Benefits Potentially Associated With CCS

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Maybe
Nitrogen Oxides	No
Sulfur Dioxide	Yes
Particulate Matter	No
Mercury	No
Other	No
Water Quantity and Quality Impacts	No
Coal Ash Ponds and Coal Combustion Residuals	No
Employment Impacts	Maybe
Economic Development	Maybe
Other Economic Considerations	No
Societal Risk and Energy Security	Maybe
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	No
Avoided Production Energy Costs	No
Avoided Costs of Existing Environmental Regulations	No
Avoided Costs of Future Environmental Regulations	Maybe
Avoided Transmission Capacity Costs	No
Avoided Distribution Capacity Costs	No
Avoided Line Losses	No
Avoided Reserves	No
Avoided Risk	No
Increased Reliability	No
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	No
Other:	

69 NETL. (2013, September). *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture.* DOE/NETL-2011/1498. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Gerdes-08022011.pdf

70 Refer to the EIA website at: http://www.eia.gov/forecasts/capitalcost/.

71 Refer to the EIA website at: http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.

cost \$72 per ton of CO_2 captured.[72] No further supporting documentation or details for these estimates appears to have been published.

A 2011 analysis published in *Energy Procedia* estimated that the revenue requirement of power plants retrofitted with post-combustion capture and using ammonia as the absorbent would vary between \$117 and \$148 per MWh.[73] The authors noted that there were limited data from which to develop their estimates and identified 11 key uncertainties that would influence the cost of capture, including the auxiliary steam loads, cooling equipment costs, and CO_2 compression.

In 2007, the Massachusetts Institute of Technology estimated that retrofitting an existing coal plant would cost \$1600 per kW and reduce net plant output by at least 40 percent.[74] The authors of this report suggested that it may be more economical to simply rebuild coal plants with more efficient supercritical or ultra-supercritical boilers (the majority of existing plants are subcritical) so as to raise the efficiency of the plant.

Although it did not present any CCS cost estimates in its 111(d) proposed rule, the EPA concluded that "the costs of integrating a retrofit CCS system into an existing facility would be substantial. For example, some existing sources have a limited footprint and may not have the land available to add a CCS system. Moreover, there are a large number of existing fossil-fired EGUs. Accordingly, the overall costs of requiring CCS would be substantial and would affect the nationwide cost and supply of electricity on a national basis."[75]

There is also little information on the cost of oxy-combustion. NETL simply states that oxy-combustion systems are not "affordable at their current level of development" owing to problems with capital cost, parasitic energy demand, and operational challenges.[76] The only power plant proposed to use this technology, FutureGen 2.0, would have had a projected gross output of 168 MW and was originally estimated to cost \$1.3 billion, but this estimate rose to \$1.65 billion.[77] That project was effectively ended in February 2015 when the DOE suspended its federal funding.

NETL estimated the cost of transporting and storing CO_2 to be anywhere from approximately \$10 to \$22 per ton of CO_2, depending on factors like capture rate, plant capacity factor, and the total quantity of CO_2 sequestered.[78] However, the Intergovernmental Panel on Climate Change puts the cost of storage alone as high as \$30 per ton of CO_2.[79]

7. Other Considerations

Any power plant, new or retrofitted, that captures CO_2 will consume significantly more water than it would otherwise. In water-constrained regions, this additional water consumption may pose a material obstacle to permitting a CCS project. Figure 7-11 shows NETL's theoretical estimates of water consumption at new power plants with and without carbon capture.

At pulverized coal plants, water consumption would likely double. Cooling water duties increase as a result of both

72 Gerdes, K. (2014, January). *NETL Studies on the Economic Feasibility of CO_2 Capture Retrofits for the US Power Plant Fleet.* US Department of Energy. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/NETL-Retrofits-Overview-2014-01-09-rev2.pdf

73 Versteeg, P., & Rubin, E. (2011). Technical and Economic Assessment of Ammonia-Based Post-Combustion CO_2 Capture. *Energy Procedia 4,* pp 1957–1964. Available at: http://www.sciencedirect.com/science/article/pii/S1876610211002736

74 Massachusetts Institute of Technology. (2007). *The Future of Coal: Options for a Carbon-Constrained World.* Available at: http://web.mit.edu/coal/The_Future_of_Coal.pdf

75 US EPA. (2014, June 18). *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule,* p. 34876. Available at: https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating

76 Refer to the NETL website at: http://www.netl.doe.gov/research/coal/energy-systems/advanced-combustion.

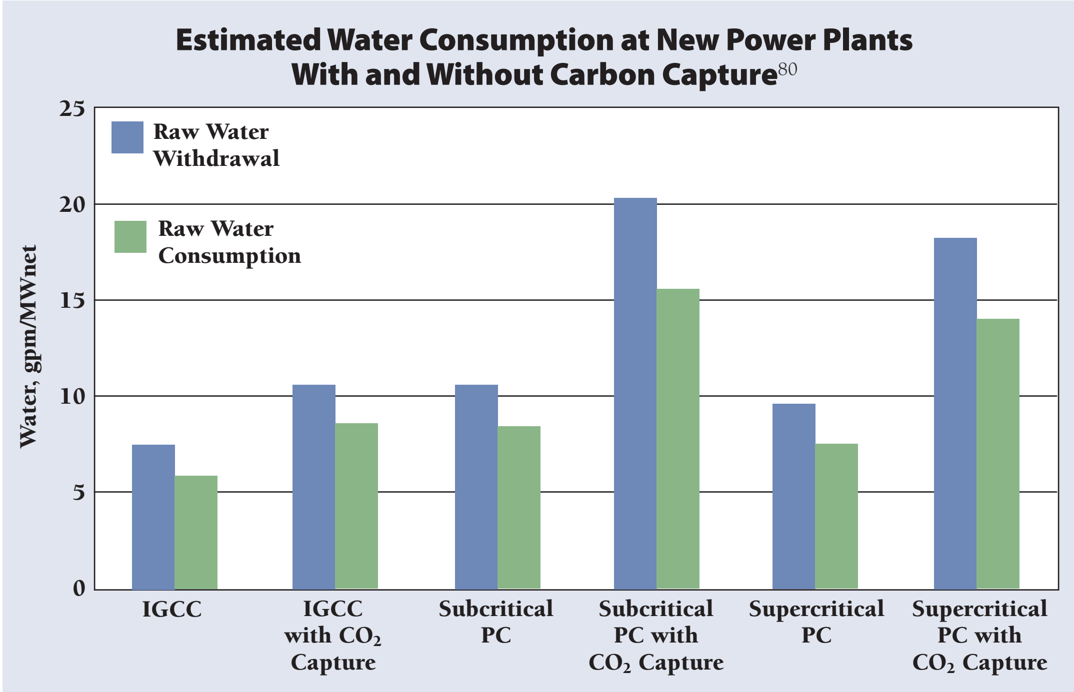
77 Folger, P. (2013, April). *FutureGen: A Brief History and Issues for Congress.* Congressional Research Service Reports. Available at: http://op.bna.com/env.nsf/id/avio-96nmz2/$File/CRS%20report%20FutureGen.pdf

78 Grant, T., Morgan, D., & Gerdes, K. (2013, March). *Carbon Dioxide Transport and Storage Costs in NETL Studies.* NETL. DOE/NETL-2013/1614. Available at: http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/QGESS_CO2T-S_Rev2_20130408.pdf

79 Supra footnote 23.

capture and compression. For example, in amine-based post-combustion capture systems, the capture reaction is exothermic, which necessitates cooling to allow the reaction to proceed as efficiently as possible. The process of compressing CO_2 nearly two orders of magnitude from 23 PSI to 2200 PSI creates enough heat to require additional cooling water as well.[81]

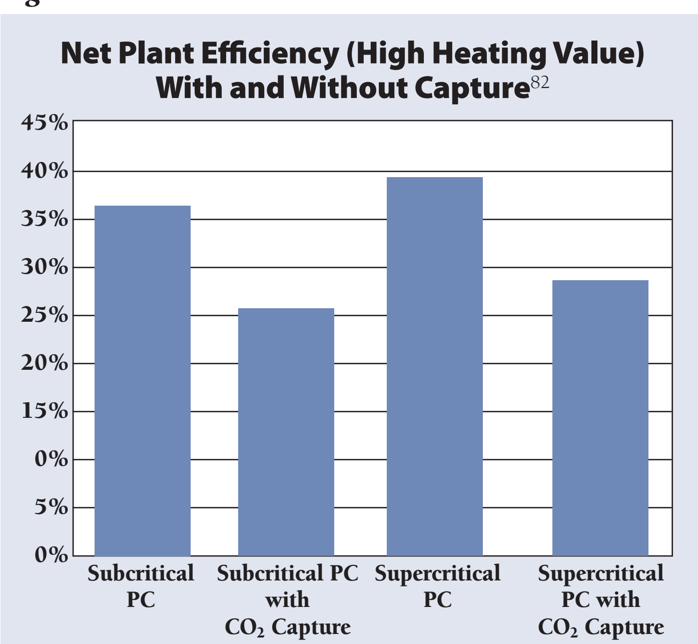
Figure 7-11



The increase in water consumption is just one of several factors contributing to an increase in auxiliary (a.k.a. "parasitic") power demand. Regenerating the solvent used to capture the CO_2 normally requires part of the plant's steam output and thereby reduces the net power output. Figure 7-12 shows the difference in plant efficiency at new pulverized coal plants with and without capture. Similar data for retrofits of existing power plants are not available owing to the lack of full-scale retrofit projects.

The decline in net plant efficiency can be thought of as a proxy for the decline in plant output, because a decrease in efficiency means that the electric output per unit of energy input has decreased. Retrofits of existing plants would be expected to result in at least the degree of change in efficiency shown for new plants in Figure 7-12 (i.e., approximately a ten-percentage-point decrease in efficiency). The *Future of Coal* study published by the Massachusetts Institute of Technology, citing data from Alstom Power, concluded that retrofitting a subcritical pulverized coal plant would reduce efficiency by about 14 percentage points, which translates to a 41-percent relative reduction in net output.[83] The Global CCS Institute

Figure 7-12



80 Based on data from: NETL. (2013, September). *Cost and Performance Baseline for Fossil Energy Plants - Volume 1: Bituminous Coal and Natural Gas to Electricity.* US Department of Energy. DOE/NETL-2010/1397. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/OE/BitBase_FinRep_Rev2a-3_20130919_1.pdf

81 NETL. (2013, September). *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture.* US Department of Energy. DOE/NETL-2011/1498. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Gerdes-08022011.pdf

82 Supra footnote 80.

83 Supra footnote 74.

offers a somewhat more optimistic assessment, estimating a parasitic load of 20 to 30 percent for post-combustion CO_2 capture and compression technologies, with net plant efficiency dropping from 38 to 27 percent.[84] The practical implication for existing plant retrofits is that this reduction in power output may have to be made up by other sources of power. This indirect cost and the possible CO_2 emissions from these other sources of power are rarely accounted for in estimates of CCS costs and benefits.

If CCS is to be used as an essential strategy for complying with mandatory CO_2 emissions regulations, some issues surrounding the coordination of ordinary power plant operations with CO_2 compression, transportation, and storage operations are likely to arise and will need to be resolved. If, for instance, the pipeline is unavailable for some reason, the plant operator would have to decide whether to vent the CO_2, shut down the plant, or find some way to store the CO_2. Some research has been done into storing CO_2-rich solvent in such situations.[85] These strategies could also be used during times of peak demand when it would be preferable to have the plant's full output.

Although many reports, including this one, may seem to blur the line, it should be emphasized that there is a difference between CO_2-EOR and carbon storage – one seeks to improve oil production and the other to sequester CO_2. A CO_2-EOR project can eventually transition to a carbon storage project,[86] but in the interim, some but not all of the CO_2 injected for EOR will be sequestered. Therefore, tons of carbon captured for the purpose of CO_2-EOR do not yield the same tons of CO_2 sequestered.

Because CO_2-EOR increases the production of oil, there may also be implications for the carbon benefit attributed to EOR-focused CCS projects. The ultimate fate of that recovered oil is combustion in some form, which in turn creates its own CO_2 emissions. Therefore, from a lifecycle perspective, the total sequestration benefit of CO_2-EOR is certainly less than the total mass of CO_2 sequestered. Indeed, a 2009 analysis of five CO_2-EOR sites found that all were net *positive* emitters of CO_2 after accounting for the combustion of the recovered oil.[87] Regulation of GHG emissions either across the entire economy or from a lifecycle perspective would account for this impact.

Economy-wide regulation of GHG could also have negative implications for the economics of CO_2-EOR projects. Although operators of EOR projects currently pay for CO_2, in a world with a price on each ton of CO_2 emitted regardless of its source, it is not clear that the EOR market would continue to *pay* for CO_2. It could be that CO_2-emitting facilities would have to compensate EOR operators for taking their CO_2 instead of receiving revenue for it. Such a shift in the EOR market could dramatically change the economics of capture projects relying on an EOR revenue stream.

Public acceptance of CCS may also play a role in its success or failure. For example, to the extent that the public perceives hydraulic fracturing (or "fracking") for oil and natural gas as the same or similar to CCS because it involves underground fluid injection, there could be a strong, negative reaction to CCS projects.[88]

84 Global CCS Institute. (2012, January). *CO_2 Capture Technologies: Post Combustion Capture (PCC)*. Available at: http://www.globalccsinstitute.com/publications/co2-capture-technologies-post-combustion-capture-pcc

85 Chalmers, H., Lucquiaud, M., Gibbins, J., & Leach, M. (2009). Flexible Operation of Coal Fired Power Plants With Postcombustion Capture of Carbon Dioxide. *Journal of Environmental Engineering, 135,* Special Issue: Recent Developments in CO_2 Emission Control Technology, 449–458. Available at: http://ascelibrary.org/doi/abs/10.1061/%28ASCE%29EE.1943-7870.0000007

86 Whittaker, S. (2010, October). *IEA GHG Weyburn-Midale CO_2 Storage & Monitoring Project*. Regional Carbon Sequestration Partnerships Annual Review. Available at: http://www.netl.doe.gov/publications/proceedings/10/rcsp/presentations/Tues%20am/Karen%20Cohen/Whittaker.%20WMP_Regional%20Partnership.pdf

87 Jaramillo, P., Griffin, W., & McCoy, S. (2009). Life Cycle Inventory of CO_2 in an Enhanced Oil Recovery System. *Environmental Science & Technology, 43,* pp. 8027–8032. Available at: http://www.ncbi.nlm.nih.gov/pubmed/19924918

88 Supra footnote 51.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on CCS.

- Metz, B., Davidson, O., de Coninck, H., Loos, M., & Meyer, L., eds. (2005). *Carbon Dioxide Capture and Storage*. Prepared by Working Group III of the Intergovernmental Panel on Climate Change. Cambridge, United Kingdom: Cambridge University Press. Available at: http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf
- Folger, P. (2013, November). *Carbon Capture: A Technology Assessment.* Congressional Research Service Reports. Available at: http://fas.org/sgp/crs/misc/R41325.pdf
- Parfomak, P. (2008, July). *Community Acceptance of Carbon Capture and Sequestration Infrastructure: Siting Challenges.* Congressional Research Service Reports. Available at: http://fas.org/sgp/crs/misc/RL34601.pdf

9. Summary

CCS offers the potential to prevent the emissions of millions of tons of CO_2 from fossil-fuel fired power plants into the atmosphere. The extent to which that potential is leveraged will be determined by our ability to overcome the technical and economic hurdles that confront this technology. Carbon capture is costly and has significant auxiliary power demands. Carbon storage may be hindered by the absence of a robust legal framework under which it can be implemented and requires further research into its functionality. It remains to be seen whether federal action – including the New Source Performance Standards for GHG emissions from utility boilers and IGCC plants and the DOE's research and development efforts in CCS – will spur sufficient interest and investment to make it a commercial technology.