Federal Control of Carbon Capture and Storage

by Arnold W. Reitze Jr.

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Editors' Summary

The United States has economically recoverable coal reserves of about 261 billion tons, which is in excess of a 250-year supply based on 2009 consumption rates. However, in the near future, the use of coal may be legally restricted because of concerns over the effects of its combustion on atmospheric carbon dioxide concentrations. In response, the U.S. Department of Energy is making significant efforts to help develop and implement a commercial-scale carbon capture and storage program to limit emissions of carbon dioxide emitted from coal-burning electric power plants based on geologic carbon sequestration in deep underground formations. Many technical and legal problems must be resolved in order to have a viable carbon capture and storage program. The many legal issues that exist can be resolved, but whether carbon sequestration becomes a commercial reality will depend on reducing its costs or imposing legal requirements on coal-fired power plants that increase the cost of electricity so that carbon sequestration is an attractive option.

I. Introduction to Coal-Fired Electric Power Generation

Fossil-fueled electric power generation in the United States is the most significant source of carbon dioxide (CO_2) emissions, which are contributing to climate change.[1] This makes the industry a primary target of efforts to reduce emissions of CO_2, which can be accomplished by: (1) improved efficiency in the generation of electricity energy or by using fossil fuel having lower carbon emissions; (2) energy conservation and improved efficiency in the use of electric power; (3) using renewable energy or nuclear power; (4) using ocean or terrestrial capture for biological sequestration; (5) mineralization of CO_2;[2] or

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1. CO_2 accounted for 85.0% of the U.S. greenhouse gas (GHG) emissions in 2008. Emissions in the United States decreased 3.0% from 2007 to 2008, but increased 16.2% from 1990 to 2008. *See* U.S. Energy Info. Admin., U.S. Dep't of Energy (DOE), DOE/EIA-0573 (2008), Emissions of Greenhouse Gases Report, tbl. 5 (2009), *available at* http://www.eia.doe.gov/oiaf/1605/ggrpt/carbon.html. Fossil-fuel combustion in 2008 was responsible for 94.1% of U.S. CO_2 emissions and 80.1% of the U.S. greenhouse gas (GHG) emissions. *Id*. Electric power plants emit 39.91% of U.S. CO_2 emissions, which makes them the most important source of CO_2 emissions, followed by transportation with 30.15%. Calculated from data from U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008, Executive Summary, tbl. ES-2 (2010), *available at* http://epa.gov/climatechange/emissions/downloads10/US-GHG-Inventory-2010_ExecutiveSummary.pdf.
2. CO_2 reacts with divalent cations with alkalinity to precipitate carbonates. The result is a rock-like material that can be placed on the ground or used as a building material. Several companies are trying to create a business using

(6) carbon capture and storage (CCS) in geological formations. It is this last approach that is the subject of this Article.[3] Because CCS operates in close conjunction with the technology used for generating electricity, a brief summary of the developing technologies related to CCS efforts will first be presented.

Coal-fired electric power plants are the most important source of electricity in the United States. The net electrical energy generated in 2009 by energy input was: 45% coal; 23% natural gas; 20% nuclear; 7% hydroelectric; 1.1% petroleum; and the remainder, less than 4%, was from renewable energy (1.9% from wind).[4] Approximately one ton of CO_2 is produced for each megawatt-hour (MWh) of electricity generated using coal,[5] but emissions vary significantly, depending on factors such as the fuel and technology used and the age of the plant.[6]

The future role of coal in generating electricity in the United States is an important policy issue that has not yet been resolved. Costs of electricity are expected to continue to rise because of the federal laws discussed in this Article, as well as state laws requiring reductions in greenhouse gases (GHGs) and laws imposing renewable energy and energy-efficiency requirements. If sequestration of CO_2 emissions is required, the cost of electricity will increase significantly. However, the cost of electricity will also increase because of more stringent environmental laws, including those aimed at controlling GHGs, which makes both carbon sequestration and using fuel other than coal more attractive options for the electric power industry.

The coal-fired electric power industry not only faces expensive regulatory requirements related to climate change, but it faces construction cost increases that threaten the economic viability of new coal-burning plants. New coal-fired plants cost $2 billion to $3 billion.[7] They are two to three times more costly than new plants built in the 1970s, even without CO_2 control. Moreover, the worldwide growth in electric power generation is creating competition for the resources and skills necessary to build plants, and that is leading to skyrocketing increases in construction costs.[8] These costs may be difficult to recover from the revenues that can be garnered in a competitive or in a regulated electric power market.[9] At the same time that costs of new power plants are increasing, there is continuing pressure to close old coal-fired power plants. One-half of the currently operating U.S. power plants were built before 1980, and they produced 73% of the CO_2 emissions from U.S. power plants in 2007.[10]

In early 2008, there were 24 coal-fired plants under construction in the United States involving $23 billion of new capital investment. These facilities would be far less polluting than older existing plants, but, if operational, they would contribute massive quantities of CO_2 to the atmosphere for a half-century or more. For this reason, opposition by environmental groups and state governments caused electric utilities to cancel or delay the construction of 100 coal-fired power plants between 2001 and mid-2009.[11] The coal industry is fighting to survive by lobbying to have the federal government dramatically increase the funding for clean coal-related programs. If they are successful in obtaining funding and the money expended results in technology advances that reduce or eliminate the threat to the planet, continued dependence on coal-fired electric power plants will likely continue.[12]

A. *Coal-Fired Power Plant Technology*

If CCS is to become an accepted method of dealing with CO_2 emissions, the technology used to generate electricity will likely play a role. CO_2 emissions are a function of the amount and type of fossil fuel burned. For new coal-burning electric power plants, the conventional technology is pulverized coal boilers, because it generates electricity at the lowest cost of any fossil fuel-based technology.[13] A

this approach. *See, e.g.*, Calera home page, http://calera.com (last visited July 25, 2011).

3. The other approaches are discussed in Arnold W. Reitze Jr., *Federal Control of Carbon Dioxide Emissions: What Are the Options?*, 36 Bos. Col. Envtl. Aff. L. Rev. 1 (2009).
4. U.S. Energy Information Administration, Electricity in the United States, *available at* http://eia.doe.gov/energyexplained/index.cfm?page=electricity_in_the_united_states; U.S. Energy Information Administration, Electric Power Industry 2009: Year in Review, *available at* http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html.
5. In 2010, the net electricity generated from coal was 1,269 million MWh. *See* U.S. Energy Info. Admin., U.S. DOE, Electric Power Monthly, tbl. 1.1 (Oct. 2010), *available at* http://www.eia.doe.gov/electricity/epm/table1_1.html. Coal used to generate electricity in 2008 was responsible for the release of 1,962.6 million metric tons of CO_2 equivalent (CO_2e) GHGs. *See* U.S. EPA, EPA 430-R-10-006, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008, tbl. 3-5 (2010), *available at* http://epa.gov/climatechange/emissions/downloads10/US-GHG-Inventory-2010_Chapter3-Energy.pdf [hereinafter EPA Emissions Inventory]. This is 1.11 metric tons per MWh.
6. *See* EPA Emissions Inventory, *supra* note 5, tbl. 3-5.
7. Dean Scott, *House Bill Carbon Incentives Lauded; Energy Industry Calls for Regulatory Certainty*, 40 Env't Rep. (BNA) 1820 (July 31, 2009).
8. *See* Press Release, Interfaith Center on Corporate Responsibility, Coal "Losing Appeal," No Longer "Predictable Investment" (Feb. 28, 2008), *available at* http://www.iccr.org/news/press_releases/2008/pr_coalpanel022608.htm.
9. Such concerns, for example, led American Municipal Power, Inc., to terminate its efforts to build a pulverized coal-fired plant in Meigs County, Ohio, after it received its air permits. *See* Molly Davis, *Lawmakers Urge Steps to Stem Closures of Coal Plants Due to Costs*, XX Clean Air Rep. (Inside EPA) 25:12 (Dec. 10, 2009).
10. Andrew Childers, *Power Plant Emissions of Carbon Equivalent Said to Be Three Times More Than All Cars*, 40 Env't Rep. (BNA) 2763 (Dec. 4, 2009).
11. Steve Cook, *With Coal-Fired Plant in Utah Canceled, Sierra Club Says 100 Facilities Shelved*, 40 Env't Rep. (BNA) 1711 (July 17, 2009). This issue is covered in more detail in Part III.B.1. below.
12. Lynn Garner, *Coal, Electricity Industries Ask White House to Double Funding for Carbon Technologies*, 39 Env't Rep. (BNA) 157 (Jan. 25, 2008).
13. G.T. Bielawski et al., *How Low Can We Go? Controlling Emissions in New Coal-Fired Power Plants*, U.S. EPA/DOE/EPRI Combined Power Plant Air

typical subcritical pulverized coal-fired power plant has an efficiency of about 37%.[14] State-of-the-art coal-fired plants, which utilize supercritical steam technology, without cogeneration, have an efficiency of about 42%, regardless of whether they are pulverized coal, pressurized fluidized bed combustion, or integrated gasification combined cycle (IGCC) facilities.[15] Ultra-supercritical pulverized coal power plants that use two reheat cycles are estimated to achieve 48% efficiency.[16]

An electric power plant's efficiency can be improved by using a combined cycle. The exhaust gas temperature from the combustion turbine of approximately 1,000 degrees Fahrenheit is used to produce high-temperature steam that drives a separate turbine. Combustion turbines have peak performance efficiencies in the mid-30% range, and steam turbines can be used to produce electricity at an efficiency in the upper-30% range. The combined efficiency of a combined-cycle plant using natural gas is approximately 59%.[17] Conventional coal-burning plants can also increase their overall efficiency by using heat that would otherwise be wasted to supply process steam to industrial or commercial customers. Such facilities are called cogeneration facilities.[18]

CO_2 produced during the combustion of fossil fuel can be reduced if less fuel is used per MWh of electricity generated, but improved efficiency usually involves increasing the temperature and pressure of the system, which adds to the cost of construction.[19] To get utilities to spend the money for additional efficiency improvements will necessitate higher prices for electricity or restrictions of carbon emissions, or both. Efficiency improvements help to facilitate CCS by reducing the amount of CO_2 to be sequestered, but efficiency improvements cannot produce the reductions from U.S. fossil fuel electric power plants that are needed to obtain the 90% reduction considered necessary to stabilize atmospheric CO_2 concentrations.[20]

B. *Technologies That Enhance the Potential for Carbon Sequestration*

1. IGCC Technology

IGCC technology is a new application of coal-gasification technology that was used to fuel street lamps during the "gaslight era" of the 1890s. In the IGCC process, coal is fed to a gasifier, where it is partly oxidized by steam under pressure. By reducing oxygen in the gasifier, carbon in fuel is converted to gas that is a mixture of hydrogen (H_2) and carbon monoxide (CO) (syngas). To enable pre-combustion capture of CO_2, the syngas is futher processed in a water gas shift reactor to convert the CO to CO_2, and additional H_2 is produced, increasing the concentration of CO_2 and H_2. The CO_2 can then be separated from the H_2 using an acid gas removal system. Because CO_2 is present at higher concentrations in syngas (after the water gas shift) than in flue gas, and because the syngas is at higher pressure, CO_2 capture is easier to accomplish and is less costly than trying to remove it using post-combustion capture.[21] Capturing pre-combustion CO_2 raises the cost of electricity by 30%, or an increase from an average of 7.8 cents per kilowatt hour (KWh) to about 10.2 cents per KWh.[22] IGCC technology, however, may be able to significantly reduce its cost in the future.[23]

In 2006, there were more than 100 commercial IGCC plants worldwide, but only about one dozen produced electricity.[24] The United States has four operating IGCC plants at full-scale operation. Only two are electric power-generating facilities,[25] which use gasification technology to produce synthetic gas to fuel a gas turbine.[26] The effort to develop IGCC facilities in the United States was dis-

Pollutant Control Symposium (Aug. 20-23, 2001), *available at* http://www.babcock.com/library/pdf/BR-1715.pdf.

14. Albert J. Bennett, Progress of the Weston Unit 4 Supercritical Project in Wisconsin 4 (Babcock & Wilcox Nov. 2006).
15. Bielawski et al., *supra* note 13. A plant can achieve this efficiency without a combined cycle or cogeneration through high temperature operation (1,085 degrees Fahrenheit) using superheated steam at 3,775 pounds per square inch gage with a reheat to 1,085 degrees Fahrenheit. However, the exhaust steam from the high-pressure turbine subsequently can be utilized in a low-pressure turbine or it can be used as process steam, which is usually at temperatures below 400 degrees Fahrenheit in order to increase efficiency. Bennett, *supra* note 14.
16. Bennett, *supra* note 14, at 4.
17. This is based on 35% turbine efficiency plus .37 (efficiency of the steam cycle) times .65 (the percentage of heat remaining in the exhaust), which produces an overall efficiency of 59%.
18. The Carnot cycle utilizes heat energy in the form of steam to produce mechanical energy to drive a generator to yield marketable and transportable electrical energy. When industrial customers use process steam from a power plant, they are utilizing heat energy rather than electrical energy. The second law of thermodynamics limits the efficiency of the Carnot cycle to [1- temperature of the heat sink/temperature of the heat source] x 100%, where the temperature is measured in degrees Kelvin.
19. Bennett, *supra* note 14. at 4.
20. U.S. DOE, National Energy Technology Laboratory (NETL), DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap 5 (Dec. 2010).
21. *Id.* at 24.
22. U.S. DOE, NETL, *Carbon Sequestration CO_2 Capture*, http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html (last visited Dec. 3, 2010).
23. *See, e.g.*, Henry W. Pennline et al., *Carbon Dioxide Capture and Separation Techniques for Power Generation Point Sources*, Presented at the Fourth Annual Conference on Carbon Capture and Sequestration (May 2-5, 2005), *available at* http://www.netl.doe.gov/publications/proceedings/05/carbon-seq/Poster%201.pdf.
24. Steve Blankinship, *Coal Gasification: Players, Projects, Prospects*, Power Engineering July 1, 2006, http://www.powergenworldwide.com/index/display/articledisplay/260509/a…10/issue-7/features/coal-gasification-players-projects-prospects.html (last visited Mar. 4, 2011).
25. In 1983, Eastman Chemical Company began commercial operation of two Texaco (now GE Energy) gasifiers at its primary chemical manufacturing facility in Kingsport, Tennessee. *See* http:www.clean-energy.us/success/Eastman.htm (last visited July 22, 2011). The process converts bituminous coal into methanol and then to acetyl chemicals produced downstream at the chemical plant. Bill Trapp et al., *Coal Gasification: Ready for Prime Time*, Power Mag. (Mar. 2004). Eastman claims its engineers have experience working on or operating over 20 gasification facilities worldwide, including "a number of petcoke and coal-fed gasifiers." Eastman Operational Expertise: The Eastman Advantage, http://www.eastman.com/Company/Industrial_Gasification/Pages/Operational_Expertise.aspx (last visited July 3, 2011). The Dakota Gasification Company has the only commercial-scale coal gasification plant in the United States that manufactures natural gas. It is located near Beulah, North Dakota, and has been in operation since 1984. *See* discussion *infra* Part II.C.
26. *See* Trapp et al., *supra* note 25, *available at* http://www.clean-energy.us/projects/eastman_power_magazine.htm.

cussed in a previous publication.[27] However, in 2010, the U.S. Department of Energy (DOE) announced that it was redesigning the FutureGen project. Rather than funding a prototype IGCC facility, DOE is supporting development of CCS technology that can be used at existing pulverized coal facilities. It will provide $1 billion to repower an existing coal-fired power plant in Morgan County, Illinois, with advanced oxy-combustion technology, which will be the world's first commercial-scale oxy-combustion power plant.[28]

2. Oxy-Coal Combustion

Oxyfuel technology is applicable to new supercritical power plants and is part of the process used in the cutting-edge IGCC technology, but the process also can be retrofitted on existing coal-fired or oil-fired power plants.[29] The oxy-fuel system uses relatively pure oxygen, rather than air for combustion. An on-site unit separates air into nitrogen and oxygen prior to combustion.[30] This is both costly and energy-intensive.[31] The nitrogen is released to the atmosphere, and the oxygen is sent to the boiler to support combustion. Because nitrogen is removed prior to combustion, much less nitrogen oxide is produced by this technology.[32] The use of oxygen, rather than air, to support combustion will cause the combustion temperature to exceed the design capability of the furnace. For this reason, some CO_2 in the flue gas is returned to the boiler to lower the temperature of combustion. New furnaces could potentially be designed to function at the higher temperatures of a pure oxygen environment, but such furnaces would require the use of new materials and new designs for heat transfer.[33]

Regardless of the technology used to combust fossil fuel, the CO_2 in the flue gas must be concentrated and pressurized before it is sequestered. Because oxy-combustion produces a flue gas with higher concentrations of CO_2 than conventional combustion, its capture costs are reduced, but that does not mean the capital cost will not be higher. Moreover, the flue gas still contains numerous contaminants.[34] To prevent corrosion of pipelines and to comply with the likely specifications for sequestration, acidic impurities need to be removed from the CO_2 stream prior to its being transported. The technology to accomplish this is still being developed. Other captured emissions that are liquids or solids are treated or sent to land disposal sites.[35]

3. Chemical Looping

In combustion using chemical looping, an air reactor is used to transfer the oxygen in air to a reduced metal or metal oxide at temperatures of 800 to 1,000 degrees Centigrade. The metal oxide is then delivered to a fluidized bed fuel reactor where coal or coal-derived syngas reacts with the metal oxide at high temperature. The air reactor and fuel reactor are each a closed loop where air and fuel never contact one another. The metal oxide delivers the oxygen needed for combustion, and the metal oxide, minus oxygen, is returned to the air reactor. The fuel reactor releases heat in a flameless combustion process with pure CO_2 and water as the products of the reaction. The chemical looping process does not require expensive air separation to produce oxygen for combustion that is needed for oxyfuel or IGCC technology. With chemical looping, the CO_2 is more concentrated than in the gas streams of other combustion processes and can be sequestered at lower costs. Unfortunately, the technology is only at the laboratory scale of development.[36]

II. Geological Carbon Sequestration

Carbon sequestration may be accomplished through storage in a geologic depository, but it will be some time in the future before sequestration in geologic formation is proven to be an effective and economical way to reduce CO_2 emissions to the atmosphere. DOE estimates that post-combustion CCS on a new pulverized-coal power plant would increase the cost of electricity by up to 80% and de-rate the plant's net generating capacity by up to 30%, due to the steam and auxiliary power required by the CCS system.[37] However, DOE's National Energy Technology Laboratory (NETL) believes CCS technologies are important to develop, so that America's abundant supply of coal could be utilized without the adverse environmental impacts associated with CO_2 emissions.[38]

In 2009, DOE stated that CCS will increase the cost of electricity from a new pulverized coal plant by about 75% and will increase the cost of electricity from a new

27. Arnold W. Reitze Jr., *Electric Power in a Carbon Constrained World*, 34 Wm. & Mary Envtl L. & Pol'y Rev. 821, 848-54 (2010) [hereinafter Reitze, *Carbon Constrained*].
28. Leora Falk, *FutureGen Selects Morgan County, Ill., Site for Carbon Storage Facility for Power Plant*, 42 Env't Rep. (BNA) 433 (Mar. 4, 2011). *See also* Steven D. Cook, *Energy Department Commits $1 Billion to FutureGen2 Carbon Capture Project*, 41 Env't Rep. (BNA) 2183 (Oct. 1, 2010); Steven D. Cook, *Department of Energy Awards $1 Billion to FutureGen Carbon Sequestration Project*, 41 Env't Rep. (BNA) 1820 (Aug. 13, 2010).
29. *See Air Products' Oxyfuel Combustion and CO_2 Capture Technology*, Air Products, http://www.airproducts.com/Responsibility/EHS/Environmental Protection/oxyfuel_combustion.htm (last visited July 3, 2011).
30. Air contains 76.85 % nitrogen by weight and 79.0% nitrogen by volume. Babcock & Wilcox Co., Steam Its Generation and Use 4-4, tbl. 3 (1960).
31. *See generally* H. Farzan et al., Babcock & Wilson Co., *State of the Art of Oxy-Coal Combustion Technology for CO_2 Control From Coal-Fired Boilers*, Presented to the Third International Technical Conference on Clean Coal Technologies for Our Future 3 (May 15-17, 2007), *available at* http://www.icac.com/files/public/B&W_Br_1793_Farzan.pdf.
32. *Id.* at 6, tbl. 4.
33. *See* Babcock & Wilcox Co., Oxy-Coal Combustion Overview 1 (2007), *available at* http://www.icac.com/files/public/B&W_Oxycomb_Overview_031507.pdf.
34. *Id.*
35. RD&D Roadmap, *supra* note 20, at 24 (Dec. 2010).
36. *See* Inst. for Clean and Secure Energy, Univ. of Utah, Combustion Chemical Looping (2008), *available at* http://www.cleancoal.utah.edu/files/CLCnew.pdf.
37. RD&D Roadmap, *supra* note 20, at 21.
38. *Id.*

advanced gasification-based plant by about 35%.[39] Overall CCS costs are estimated at $60 per ton of CO_2 for a new IGCC facility, $95 per ton for a new post-combustion facility, $114 per ton for a new natural gas facility, and $103 per ton for retrofit to an existing coal-fired plant.[40]

The capital costs of adding capture technology to a new IGCC is estimated to be $400 million, and post-combustion capture of CO_2 is estimated to require $900 million in capital cost.[41] The added cost is projected by a Massachusetts Institute of Technology study to nearly double the cost of a KWh of electricity.[42] This may encourage the use of funding mechanisms that hide the costs of CCS, such as investment tax credits, carbon sequestration credits, subsidies funded from a cap-and-trade program, federal loan guarantees, and federal financing.[43]

The cost of sequestration will be added to the costs of updating an inadequate transmission system, updating or replacing aging generation assets, investing in advanced metering equipment, expanding the electric power-generating capacity to deal with power demand, and investing to meet renewable portfolio requirements. For this reason, a presidential task force report issued August 12, 2010, says that placing a price on carbon emissions is crucial if CCS is to be quickly deployed.[44]

A. CO_2 Capture

CCS begins by separating CO_2 from other gases, which may be done before or after fuel is combusted.[45] Pre-combustion capture was discussed in Part I.B. Post-combustion capture is the more important, because it can be used to capture CO_2 from conventional fossil fuel facilities. CO_2 may be captured from fossil-fueled power plants or from industrial processes, including the production of hydrogen and other chemicals, the production of substitute natural gas, and the production of transportation fuel.[46]

The majority of the costs of CCS is incurred in separating and capturing CO_2 from flue gas.[47] Carbon capture from the flue gas of a coal-burning power plant is more expensive than the carbon capture involving industrial processes, because the lower concentration of CO_2 in coal-fired power plant post-combustion gas streams of about 13% to 15% CO_2 by volume requires large volumes of flue gas to be processed to remove pollutants. Carbon capture from most conventional power plants that use pulverized coal would require post-combustion capture using technologies like amine-based chemical solvents, such as aqueous methoethanolanimine (MEA). Conventional power plants are limited in their use of solvents that are commonly used to remove CO_2 from natural gas because the dilute concentration of CO_2 makes the use of solvents too costly.[48] Power plant CO_2 removal results in a parasitic power demand, requires a significant amount of additional cooling water, and has not been demonstrated at the large scale required for a coal-fired power plant.[49]

If nitrogen in the air is removed prior to combustion, such as occurs in both the oxyfuel and IGCC process, it is less costly to separate a given amount of CO_2 than is the case with conventional power plants because its concentration is higher, therefore less energy is required to remove CO_2.[50] If the technology for removal could be improved, carbon capture could become less energy-intensive, which would lower the cost of CCS.[51]

The CO_2 that is removed from the exhaust gas stream must be concentrated into a stream of nearly pure CO_2, and compressed to convert it from gas to a supercritical fluid before it is transported to the injection site.[52] The energy required to liquefy CO_2 reduces the efficiency of the electric generation process. Carbon capture from a new IGCC plant is estimated to increase the cost of electricity production by less than one-half the cost of carbon capture from a new pulverized coal plant, because the higher concentration of CO_2 in the IGCC gas stream lowers the energy requirements for liquefying the CO_2, although capital costs could be higher.[53] However, because pulverized coal plants generate 99% of the electricity produced in the United States from burning coal, the potential benefits of IGCC are not as important as finding a cost-effective way to use CCS at conventional coal-fired facilities.[54] At this time, it is unlikely that CCS will be deployed unless carbon emissions are limited by law or a significant cost is imposed on emissions.

B. CO_2 Transport

Liquefied CO_2 must be transported to a storage site for underground injection. This will be costly because a 1,000-MW plant consumes about 13,000 tons of coal each day.[55] The weight of CO_2 that will need to be shipped will be more than double the weight of the coal that was used by the power plant, with the exact weight being dependent

39. U.S. DOE, *Carbon Capture and Storage R&D Overview*, http://www.fossil.energy.gov/programs/sequestration/overview.html (last visited July 23, 2011).
40. RD&D Road Map, *supra* note 20, at 25.
41. RD&D Road Map, *supra* note 20, at 24.
42. The Future of Coal, Summary Report 19 (Mass. Inst. of Tech. 2007).
43. Steven D. Cook, *Dorgan Report See Minimum of $110 Billion Needed to Deploy Carbon Capture, Storage*, 40 Env't Rep. (BNA) 2762 (Dec. 4, 2009).
44. *Report of the Interagency Task Force on Carbon Capture and Storage* (Aug. 12, 2010), *available at* http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf.
45. *See* U.S. Gov't Accountability Office (GAO), GAO-08-1080, Climate Change: Federal Actions Will Greatly Affect the Viability of Carbon Capture and Storage as a Key Mitigation Option 9 (2008), *available at* http://www.gao.gov/new.items/d081080.pdf [hereinafter GAO].
46. *See id.* at 33.
47. *See Carbon Sequestration*, NETL, http://www.netl.doe.gov/technologies/carbon_seq/index.html (last visited July 23, 2011).
48. GAO, *supra* note 45, at 18.
49. RD&D Roadmap, *supra* note 20, at 23, 25, 26.
50. *See* Inst. for Clean and Secure Energy, Univ. of Utah, Oxyfuel (2009), *available at* http://www.cleancoal.utah.edu/files/oxynew.pdf.
51. GAO, *supra* note 45, at 31.
52. *Id.* at 22.
53. *Id.* at 19.
54. *Carbon Sequestration: CO_2 Capture*, NETL, http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html (last visited July 23, 2011).
55. *See* Power 4 Georgians, http://power4georgians.com/wcpp.aspx (last visited July 23, 2011).

on the moisture content and carbon content of the fuel.[56] Thus, a 1,000-MW power plant produces about 26,824 tons of CO_2 per day.[57] CO_2 in the supercritical state used for injection has a density of 0.03454 cubic feet per pound, or about 69 cubic feet per ton.[58] Thus, a modern power plant could be expected to need to transport over 1.85 million cubic feet each day of super critical CO_2. The United States produced 2,342 million metric tons of CO_2 in 2007 from the generation of electricity,[59] which could result in the generation of 165,407 million cubic feet per year, which is more than a cubic mile of supercritical CO_2.[60]

It is expected that pipelines will be the primary method of transporting CO_2 to a sequestration site. There are approximately 3,600 miles of pipeline in the United States used to transport CO_2, primarily located in Texas and Wyoming. Most of these pipelines transport CO_2 to be used for enhanced oil recovery. A dedicated pipeline network needs to be created if large-scale CCS is to occur,[61] but its size and configuration cannot be determined until the number, size, and characteristics of the sequestration sites are known. A 2004 study estimated the cost of pipeline construction in 2002 dollars was about $800,000 per mile, and the costs have increased substantially since the study was completed.[62]

C. CO_2 Storage

CO_2 is transported to an underground storage location under high pressure as a supercritical fluid that is injected into underground geological formations and monitored.[63] There appear to be more than adequate geological formations to use as potential storage reservoirs, although detailed study will need to be performed prior to using a specific location as a CO_2 repository.[64] Estimated storage capacity in the United States is over 3,500 gigatons of CO_2 (Gt CO_2), although the actual capacity may be lower once site-specific technical and economic considerations are addressed. Even if only a fraction of that geologic capacity is used, CCS could play an important role in mitigating U.S. GHG emissions.[65]

CO_2 storage can be based on solubility trapping, hydrodynamic trapping, physical adsorption, and mineral trapping.[66] Solubility trapping involves saltwater containing CO_2 sinking to the bottom of a rock formation.[67] With hydrodynamic trapping, the relatively buoyant CO_2 rises in the formation until it reaches a stratigraphic zone with low permeability, such as shale or carbonates, that inhibits migration of the CO_2 from the porous formations, such as sandstone, where it is stored.[68] The pore spaces that will receive the CO_2 are rarely empty; they usually contain other gases and liquids, primarily brine, that will be displaced or have their pressure increased by the injection.[69] In physical adsorption, CO_2 molecules are trapped at near liquid-like densities on micropore wall surfaces of coal seams or shales. In mineral trapping, CO_2 reacts chemically with minerals in the geological formation and forms solid minerals.[70] Mineral trapping results in the most stable form of geological CO_2 sequestration[71] It is expected that the supercritical liquid CO_2 will be injected, using proven technology, at depths of over 800 meters (2,625 feet) into geological formations that will sequester it for hundreds to thousands of years.[72] CO_2 has been trapped for more than 65 million years under the Pisgah Anticline, northeast of the Jackson Dome in Louisiana and Mississippi. Other natural CO_2 sources include the following geologic domes:

56. Coal is a mixture of carbon, hydrogen, and oxygen molecules, with carbon making up about 90% of the weight of a typical coal molecule, but coal also contains impurities; in the case of Powder River Basin coal about 74.1% of dry coal is carbon, but the coal consumed is wet with a 24% moisture content. The carbon in the coal combines with oxygen in the air to produce CO_2 that weighs 3.664 times the weight of the carbon based on the atomic weights of oxygen and carbon. Babcock & Wilcox, *supra* note 33, at 2-4, 2-8, tbl. 10; B.D. Hong & E.R. Slatick, Energy Information Administration, *Carbon Dioxide Emission Factors for Coal*, Energy Information Administration Quarterly Coal Report (Aug. 1994), *available at* http://www.eia.doe.gov/cneaf/coal/quarterly/co2_article/co2.html.
57. For a Powder River Basin coal, 13,000 tons of coal per day minus its moisture content multiplied by its carbon content is the weight of the carbon and multiplied by the relative weight of CO_2 will produce 26,824 tons per day of CO_2 (13,000 x .76 x .741 x 3.664). Calculated from data found in Babcock & Wilcox, *supra* note 33, at 2-8, 2-9.
58. Chemical Engineer Handbook, 5th. ed. 3-162 (Robert H. Perry ed. 1953). The IGCC Special Report provides a range of numbers, but says the density is 1,032 kilograms per cubic meter at 20 degrees C and 19.7 bar pressure, which converts to 64.4 pounds per cubic foot. *See* Paul Freund et al., IPCC Special Report on Carbon Dioxide Capture and Storage, Annex 1: Properties of CO_2 and Carbon-Based Fuels, *available at* http://www.ipcc.ch/pdf/special-reports/srccs/srccs_annex1.pdf.
59. 2010 Inventory of U.S. Greenhouse Gases, Executive Summary, *supra* note 1, at ES-8.
60. A cubic mile is 147,197 million cubic feet.
61. Elizabeth Burton et al., Cal. Energy Comm. & Dep't of Conservation, Geologic Carbon Sequestration Strategies for California: Report to the Legislature 24-25 (2007), *available at* http://www.energy.ca.gov/2007publications/CEC-500-2007-100-SD.PDF. The U.S. Department of Transportation (DOT), National Pipeline Mapping System database does not allow the public to access the location of pipelines. *See* http://www.npms.phmsa.dot.gov (last visited July 23, 2011).
62. Paul W. Parformak & Peter Folger, Cong. Res. Service, Carbon Dioxide (CO_2) Pipelines for Carbon Sequestration: Emerging Policy Issues, CRS-12 (2007).
63. GAO, *supra* note 45, at 1.
64. The Future of Coal, *supra* note 42, at 44.
65. Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells; Final Rule, 75 Fed. Reg. 77229, 77234 (Dec. 10. 2010).
66. RD&D Roadmap, *supra* note 20, at 49.
67. *Id.*
68. *Id.* at 50.
69. Alexandra B. Klass & Sara E. Bergan, *Carbon Sequestration and Sustainability*, 44 Tul. L. Rev. 237, 248 (2008). Physical trapping can also occur as residual CO_2 is immobilized in formation pore spaces as disconnected droplets or bubbles at the trailing edge of the plume due to capillary forces. A portion of the CO_2 will dissolve from the pure fluid phase into native groundwater and hydrocarbons. Preferential sorption occurs when CO_2 molecules attach to the surfaces of coal and certain organic-rich shales, displacing other molecules, such as methane. Geochemical trapping occurs when chemical reactions between the dissolved CO_2 and minerals in the formation lead to the precipitation of solid carbonate minerals (IPCC, 2005). The time frame over which CO_2 will be trapped by these mechanisms depends on properties of the receiving formation and the injected CO_2 stream. 75 Fed. Reg. at 77233.
70. RD&D Roadmap, *supra* note 20, at 50.
71. *Id.*
72. U.S. EPA, EPA Proposes New Requirements for Geologic Sequestration of Carbon Dioxide (July 2008) [EPA 816-F-08-032]. At temperatures above supercritical temperature, a material cannot be distinguished between its liquid or gas phase. The critical temperature for CO_2 is 88 degrees Fahrenheit.

McElmo Dome, Sheep Mountain, and Bravo Dome in Colorado and New Mexico.[73]

CO_2 injection is used to enhance oil recovery (EOR) and to force methane out of coal beds for recovery and use.[74] The oil and natural gas industry in the United States has over 35 years of experience injecting and monitoring CO_2 in the deep subsurface for the purposes of enhancing oil and natural gas production.[75] We do not have much experience with injection on the scale that will be required for geological storage of CO_2 from electric power plants for time spans in excess of human civilization. Such storage will require dealing with the properties of flue gas from fossil-fuel combustion. That includes the relative buoyancy of CO_2, its mobility within subsurface formations, the corrosive properties of the gases in water, the impact of the impurities in the flue gas, and the large volume of material that will need to be injected.

It is estimated by the International Energy Agency that about 10,000 large-scale CCS projects will be needed by 2050 to limit global warming to three degrees Celsius by the end of this century. There are only a few, including Sleipner in the Norwegian North Sea and Snohvit in the Barents Sea, Norway, that are operated by StatoilHydro; the Salah gas project in Algeria operated by British Petroleum, Somatrach, and StatoilHydro; and the North Dakota/Canadian facility discussed below.[76] None of these existing sequestration projects was designed for long-term storage. They all are used to enhance hydrocarbon recovery. Since 1996, the Sleipner project has captured about 3,000 metric tons of CO_2 per day from its natural gas extraction, and it is stored 800 meters under the North Sea's seabed in a saline reservoir.[77] Other projects include Otway in Australia (operating since 2008); Ketzin in Germany (operating since 2008); and Lacq in France (operating since 2009). Two projects that are anticipated to begin injection in the near future are CarbFix in Iceland (anticipated to commence injection in 2010) and Gorgon in Australia (anticipated to start in 2014).[78]

The only coal-burning facility in North America that sequesters CO_2 is the Great Plains Synfuels Plant in North Dakota, owned by the Dakota Gasification Company that is a subsidiary of Basin Electric Cooperative. It is a synthetic natural gas facility where coal is gasified to make methane; CO_2, sulfur dioxide (SO_2), and mercury are removed from the gas stream. The gas stream, which is 96% CO_2, is pressurized until it is in a supercritical state, which results in the gas becoming as dense as a liquid, but it flows like a gas. It is then shipped 205 miles by pipeline to an oil field near Weyburn, Saskatchewan, Canada, where it is injected into one of the 37 injection wells and is used to enhance oil recovery. The facility began sequestrating CO_2 in 2000. It handles 8,000 metric tons of CO_2 each day and is expected to eventually store 20 million tons 1,400 meters underground.[79]

President Barack Obama announced on February 3, 2010, that he was establishing an interagency task force to speed the development of CCS technologies, and its primary mission was to get five to 10 commercial-scale sequestration projects operational by 2016.[80] On September 7, 2010, DOE announced it had selected 22 projects to share $575 million in federal funding to accelerate CCS development.[81]

III. Federal Legal Requirements Applicable to Carbon Sequestration

CO_2 injection into underground formations has been used for decades to enhance oil and natural gas production.[82] This practice has been primarily regulated by state law.[83] Because CCS is expected to be used for much larger scale operations to sequester power plant CO_2 emissions, the federal government is beginning to play a more important regulatory role. The federal legal requirements imposed on the electric power industry will help determine whether CCS becomes a viable control technology. Because of the estimated high costs of CCS, it will be adopted only if legally mandated or if the cost of emitting CO_2 is increased so that CCS becomes an economically viable option. But even if emissions of CO_2 are subject to a financial charge imposed by legislation, such as cap and trade, it would take many years for industry to adopt CCS and many more years for the technology to be commonly utilized.[84] Environmental laws also affect decisions concerning CCS by changing the economic climate for electricity production. More stringent controls on conventional air pollutants, toxic air emissions, and potential new controls on fly ash disposal will increase the cost of coal-fired electric power generation. This will make alternative methods of electric power generation such as nuclear and renewable sources more attractive, while also making CCS a more economically defensible choice for electric power companies.

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73. 75 Fed. Reg. at 77234.
74. Steven D. Cook, *Site Selection Criteria Recommended for Geologic Storage of Carbon Dioxide*, 40 Env't Rep. (BNA) 1292 (June 5, 2009).
75. 75 Fed. Reg. at 77234.
76. Rick Mitchell, *IEA Says 10,000 Large-Scale Projects Needed by 2050 to Meet Climate Goals*, 39 Env't Rep. (BNA) 2223 (Nov. 7, 2008); GAO, *supra* note 45, at 17; Alexandra B. Klass & Elizabeth J. Wilson, *Climate Change and Carbon Sequestration: Assessing a Liability Regime for Long-Term Storage of Carbon Dioxide*, 58 Emory L.J. 103, 107, n.7 (2008).
77. GAO, *supra* note 45, at 28. For a list of sequestration projects throughout the world, see *RD&D Projects Database*, IEA Greenhouse Gas R&D Programme, *available at* http://co2captureandstorage.info/co2db.php.
78. 75 Fed. Reg. at 77238.
79. *See International CO_2 Sequestration Success Story*, Basin Electric Power Cooperative, *available at* http://www.basinelectric.com:80/Gasification/CO2/index.html.
80. Lynn Garner, *Obama Establishes Interagency Task Force to Expedite Carbon Capture at Power Plants*, 41 Env't Rep. (BNA) 263 (Feb. 5, 2010).
81. Alan Kovski, *Funds Awarded for Research, Development on Carbon Capture, Improved Combustion*, 41 Env't Rep. (BNA) 1995 (Sept. 10, 2010).
82. *See supra* Part II.C.
83. *See generally* Arnold W. Reitze Jr. & Marie Bradshaw Durrant, *State and Regional Control of Geological Carbon Sequestration (Part 1)*, 41 ELR 10348 (Apr. 2011).
84. Cong. Budget Off., 110th Cong., The Potential for Carbon Sequestration in the United States 20 (2007), *available at* http:www.cbo.gov/ftpdocs/86xx/doc8624/09-12-CarbonSequestration.pdf.

A. Safe Drinking Water Act

The Safe Drinking Water Act (SDWA)[85] Part C requires the U.S. Environmental Protection Agency (EPA) to establish minimum requirements for state underground injection control (UIC) programs that regulate the subsurface injection of fluids onshore and offshore under submerged lands within the territorial jurisdiction of states.[86] The SDWA is designed to protect the quality of drinking water sources in the United States and prescribes that EPA issue regulations for state UIC programs that contain "minimum requirements for effective programs to prevent underground injection which endangers drinking water sources."[87] Underground injection of CO_2 waste streams led to regulations under the SDWA to address the risks presented by this technology.

EPA initially promulgated UIC regulations in 1980 for five classes of injection wells.[88] These regulations now apply to over 800,000 injection wells nationwide.[89] Class I wells are used to inject hazardous waste below sources of drinking water.[90] Class II wells are those that inject fluids (e.g., CO_2 or brine) to enhance conventional oil or natural gas production or to store hydrocarbons that are liquid at standard temperature and pressure. Class II CO_2 injection wells designated for EOR and enhanced gas recovery (EGR) technologies, collectively referred to as enhanced recovery (ER), are used to repressurize the reservoir, and in the case of oil, to increase its mobility in order to increase production.[91] As of 2008, there were 105 CO_2-EOR projects within the United States.[92]

Class V injection wells are those not included in Class I, II, III, or IV.[93] Class V permits are used for experimental technologies. CO_2 injection projects have been permitted as Class V experimental technology wells for the purpose of testing geological sequestration (GS) technology.[94] EPA issued technical guidance to assist state and EPA Regional UIC programs in processing permit applications for pilot and other small-scale experimental GS projects in 2007.[95] EPA stated that the UIC Program Guidance #83 continues to apply to experimental projects (as long as the projects continue to qualify as experimental technology wells under the guidelines described in the guidance) and to future projects that are experimental in nature. The Agency is preparing additional guidance for owners or operators and Directors regarding the use of the Class V experimental technology well classification for GS after it promulgated the final rule of December 10, 2010.[96]

The pressure created by injection of CO_2 could push brine through geological formations into drinking water sources, which could render them unusable. When CO_2 contacts water, acids could form that would leach minerals (e.g., arsenic, lead) and organic compounds from the rock formations contaminating groundwater. Adverse effects could be exacerbated by the contaminants found in the injected waste streams, such as hydrogen sulfide or mercury.[97] This led EPA to propose a rule governing underground injection of CO_2 under the SDWA on July 25, 2008.[98] A final rule was promulgated December 10, 2010, with an effective date of January 10, 2011.[99] It applies to owners or operators of wells that will be used to inject CO_2 into the subsurface for the purpose of long-term storage.

The rule creates a new Class VI category for wells used for CCS in addition to the five classes of wells that already require permits. The rule applies to subsurface GS of a gaseous, liquid, or supercritical CO_2 stream. It does not apply to CO_2 capture or transport.[100] The rule sets minimum technical criteria for Class VI wells that include: site evaluation to ensure wells are located in suitable formations and are constructed to prevent fluid movement; modeling of the site to account for the properties of CO_2; periodic reevaluation of the CO_2 plume; well construction requirements; injection and post-injection monitoring; and financial responsibility requirements.[101]

A related problem under the SDWA is the practice of fracking that is used by the oil and gas industry. The process injects fluids under pressure to fracture rock through hydraulic action to create and enhance cracks through which oil or natural gas can flow to a well.[102] The 2005 Energy Policy Act exempts this practice from federal regulation under the SDWA, except when diesel is used as the fluid. However, EPA, on March 18, 2010, announced it was commencing a study to evaluate the potential risks to

85. 42 U.S.C. §§300f to 300j-26, ELR Stat. SDWA §§1401-1465.
86. SDWA §§1421 et seq., 42 U.S.C. §§300h et seq. The chief goal of any federally approved UIC program is the protection of USDW. This includes not only those formations that are presently being used for drinking water, but also those that can reasonably be expected to be used in the future. EPA has defined through its UIC regulations that USDWs are underground aquifers with less than 10,000 milligrams per liter (mg/L) total dissolved solids (TDS) and which contain a sufficient quantity of groundwater to supply a public water system. 40 C.F.R. §144.3.
87. 42 U.S.C. §300h(b)(1) (West 2010).
88. 40 C.F.R. §144.6 (2010).
89. 75 Fed. Reg. 77237 (Dec. 10, 2010).
90. 40 C.F.R. §144.6(a) (2010).
91. 75 Fed. Reg. 77244 (Dec. 10, 2010).
92. *Id.* The majority (58) of the ER projects are located in Texas, and the remaining projects are located in Colorado, Kansas, Louisiana, Michigan, Mississippi, New Mexico, Oklahoma, Utah, and Wyoming. CO_2 EOR projects recovered 6.5% of total domestic oil production in 2008. A total of 6,121 CO_2 injection wells among 105 projects were used to inject 51 million metric tons of CO_2. *Id.*
93. 40 C.F.R. §144.6(e).
94. 40 C.F.R. §144.81(14).
95. UIC Program Guidance #83: Using the Class V Experimental Technology Well Classification for Pilot Carbon GS Projects (U.S. EPA, 2007) provides recommendations for permit writers regarding the use of the UIC Class V experimental technology well classification at demonstration GS projects while ensuring USDW protection.
96. Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells, Final Rule, 75 Fed. Reg. 77229, 77238 (Dec. 10, 2010) (to be codified at 40 C.F.R. pts. 124, 144, 145 et seq.) [hereinafter UIC Rule].
97. Klass & Bergan, *supra* note 69, at 248.
98. Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells, 73 Fed. Reg. 43491 (proposed July 25, 2008). EPA published supplemental material at 74 Fed. Reg. 44802 (Aug. 31, 2009).
99. UIC Rule, 75 Fed. Reg. at 77230.
100. UIC Rule, 75 Fed. Reg. at 77231.
101. UIC Rule, 75 Fed. Reg. at 77230.
102. Alan Kosvki, *Advocates Ask EPA to Study Water Pollution From Oil, Gas Drilling, Hydraulic Fracturing*, 41 Env't Rep. (BNA) 499 (Mar. 5, 2010).

groundwater from fracking that is mandated by its 2010 appropriations law.[103] Since CO_2 sequestration acts as a hydraulic fluid, it potentially will be impacted by any new regulatory developments concerning fracking. Legislation has been introduced that would give EPA authority to regulate fracking under the SDWA.[104] Another bill would modify the Emergency Planning and Community Right-To-Know Act (EPCRA) to allow states to require disclosure of chemicals used in fracking operations.[105] But it is unknown whether any legislation or regulation that may emerge will extend to CCS.

1. Class VI Permits

The Class VI injection well program, promulgated December 10, 2010, provides minimum federal requirements that protect underground sources of drinking water (USDW) from endangerment created by injection of CO_2 for geological sequestration.[106] EPA foresees increased risk to USDWs compared to traditional Class II operations, due to the high volumes of CO_2 that will likely be injected.[107] The December 10, 2010, rule includes requirements for permitting, siting, construction, operation, financial responsibility, testing and monitoring, post-injection site care (PISC), and site closure of Class VI injection wells.[108] Class VI GS requirements do not apply to Class II ER wells if oil or gas production is occurring, but they will apply after the oil and gas reservoir is depleted. Traditional ER projects are not impacted by the December 10, 2010, rule, and will continue operating under Class II permitting requirements,[109] but Class VI requirements apply to any CO_2 injection project when there is an increased risk to USDWs, as compared to traditional Class II operations injecting CO_2.[110]

Owners and operators of Class II wells injecting CO_2 for the primary purpose of long-term storage into an oil and gas reservoir must apply for and obtain a Class VI permit. A Class VI permit is issued for the life of the GS project, including the PISC period.[111] However, owners or operators of Class VI wells must periodically reevaluate the area of review (AoR), which is defined as, "the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity.[112] The various mandated plans must be reevaluated and updated by the owner or operator throughout the life of the project.[113] To assist owners and operators implement the Class VI well rule, EPA released draft guidance documents in March 2011.[114]

a. Site Characterization

Owners or operators of Class VI wells must perform a detailed assessment of the geologic, hydrogeologic, geochemical, and geomechanical properties of the proposed GS site to ensure that GS wells are sited in appropriate locations and injections are made into formations that are suitable because they are free of geological faults or fractures and are able to confine the injected CO_2 to assure USDW protection.[115] Minimum siting criteria are set forth at 40 C.F.R. §146.83.[116]

Permit applicants must submit comprehensive site-specific plans that include an AoR and corrective action plan, a monitoring and testing plan, an injection well plugging plan, a PISC and site closure plan, and an emergency and remedial response plan. The Director will evaluate the plans to ensure that planned activities at the facility are appropriate to the site-specific circumstances and address all risks of endangerment to USDWs.[117]

b. AoR and Corrective Action

The final rule at 40 C.F.R. §146.84 enhances the existing UIC requirements for AoR and corrective action to require modeling of the AoR for GS projects to account for the physical and chemical properties of the injected CO_2 based on available site characterization, monitoring, and operational data as set forth in §146.84."[118] Owners or operators must periodically reevaluate the AoR to incorporate monitoring and operational data and verify that the CO_2 is moving as predicted within the subsurface.[119]

Owners or operators must develop and implement an AoR and corrective action plan, which, if approved, will be incorporated into the Class VI permit and will be considered permit conditions[120]; failure to follow the plan will result in a permit violation under 42 U.S.C. §300h-2.[121] Owners or operators must also review the AoR and corrective action plan following an AoR reevaluation and submit an amended plan, or demonstrate to the Director that no amendment to the AoR and corrective action plan is needed.[122]

103. *EPA Plans Broad Fracking Risk Study, Boosting Industry's Uncertainty*, XXVII Envtl. Pol'y Alert (Inside EPA) 7:35 (Apr. 7, 2010); Alan Kovski, *Science Panel Suggests Risk Assessment to Guide EPA Study on Hydraulic Fracturing*, 41 Env't Rep. (BNA) 847 (Apr. 16, 2010).
104. *Senate Climate Bill Would Mandate Disclosure of "Fracking" Chemicals*, XXVII Envtl. Pol'y Alert (Inside EPA) 10:38 (May 19, 2010); *Activists Urge Senators to Reject Industry Fracking Measure in Climate Bill*, XXVII Envtl. Pol'y Alert (Inside EPA) 7:35 (Apr. 7, 2010). *See also* Alan Kovski, *State Regulators Say Hydraulic Fracturing Produces Debate, but Not Water Problems*, 41 Env't Rep. (BNA) 1101 (May 14, 2010).
105. *Senate Oil Spill Response Bill Requires Disclosure of "Fracking" Chemicals*, XXVII Envtl. Pol'y Alert (Inside EPA) 16:35 (Aug. 11, 2010).
106. UIC Rule, *supra* note 96.
107. UIC Rule, 75 Fed. Reg. at 77245.
108. UIC Rule, 75 Fed. Reg. at 77246.
109. UIC Rule, 75 Fed. Reg. at 77245.
110. UIC Rule, 75 Fed. Reg. at 77244.
111. 40 C.F.R. §144.36 (2010).
112. *Id.*
113. UIC Rule, 75 Fed. Reg. at 77273.
114. Draft guidance documents are available at http://water.epa.gov/type/undergroundwater/uic/class6/gsguidedoc.cfm (last visited July 6, 2011).
115. The material that follows concerning the final GS rule is based on the final GS rule's preamble.
116. UIC Rule, 75 Fed. Reg. at 77247.
117. UIC Rule, 75 Fed. Reg. at 77248.
118. UIC Rule, 75 Fed. Reg. at 77231, 77249.
119. UIC Rule, 75 Fed. Reg. at 77248.
120. *Id.*
121. 42 U.S.C. §1423.
122. SDWA §300j(e)(4), 42 U.S.C. §146.84(e)(4).

Delineation of the AoR is to be reevaluated periodically over the life of the project in order to incorporate new CO_2 monitoring data into models to ensure protection of USDWs. If the CO_2 plume and pressure front move as predicted, the burden of the AoR reevaluation requirement will be minimal.

Owners or operators of Class VI wells must identify and evaluate all artificial penetrations within the AoR, and, in consultation with the Director, wells needing corrective action are to be identified to prevent the movement of CO_2 or other fluids into or between USDWs. Owners or operators are to perform corrective action to address deficiencies in any wells that are potential conduits for fluid movement into USDWs.[123] EPA allows corrective action to be phased in to spread costs over the life of the project.[124]

c. Injection Well Construction

Class VI wells must be constructed using materials that can withstand contact with CO_2 over the life of the GS project in order to prevent movement of fluids into USDWs.[125] Proper construction of injection wells provides multiple layers of protection to ensure the prevention of fluid movement into USDWs. The final rule is based on existing construction requirements for surface casing, long-string casing, and tubing and packer for Class I hazardous waste injection wells, with modifications to address the unique physical characteristics of CO_2, including its buoyancy relative to other fluids in the subsurface and the potential presence of impurities in captured CO_2.[126]

d. Class VI Injection Depth Waivers

Owners or operators may seek a waiver from the Class VI injection depth requirements for GS to allow injection into non-USDW formations while ensuring that USDWs above and below the injection zone are protected from endangerment.[127] The final injection depth waiver requirements apply to all non-USDWs including: (1) Formations that have salinities greater than 10,000 milligrams per liter (mg/l) total dissolved solids (TDS); and (2) all eligible previously exempted aquifers situated above and/or between USDWs. EPA believes that collection and assessment of site- and project-specific information is integral to the waiver process.

States may develop requirements that are more stringent than the minimum federal requirements provided in the Class VI rule. States, territories, and tribes seeking primacy to regulate Class VI wells are not required to provide for injection depth waivers in their UIC regulations and may choose not to make this process available to owners or operators of Class VI wells under their jurisdiction. No waivers may be issued by a state prior to the establishment of a Class VI UIC program in the state.

e. Injection Well Operation

Class VI injection wells' operational requirements are based on the existing requirements for Class I wells, with enhancements to account for the unique conditions that will occur during GS, including buoyancy, corrosivity, and higher sustained pressures over a longer period of operation. EPA proposed that owners or operators limit injection pressure so that it does not exceed 90% of the fracture pressure of the injection zone, and the injection does not initiate new fractures or propagate existing fractures. The fracture pressure, which determines the injection pressure limit, is calculated based on site-specific geologic and geomechanical data collected during the site characterization process.[128]

f. Testing and Monitoring

The final rule requires owners or operators of Class VI wells to develop and implement a comprehensive testing and monitoring plan for their projects,[129]which includes a mechanical integrity test (MIT) to verify proper well construction, operation, and maintenance.[130] External well MIT is demonstrated by establishing the absence of significant fluid movement along the outside of the casing, generally between the cement and the well structure, and between the cement and the well-bore.[131] Monitoring data can be used to verify that the injectate is safely confined in the target formation, to minimize costs, to maintain the efficiency of the storage operation, to confirm that injection zone pressure changes follow predictions, and to serve as inputs for AoR modeling.

Monitoring requirements are based on existing UIC regulations, tailored to address the needs and challenges posed by GS projects. The testing and monitoring requirements for Class VI wells at 40 C.F.R. §146.90 incorporate elements of preexisting UIC requirements for monitoring and testing, tailored and augmented as appropriate for GS projects. Owners or operators of Class VI wells are to submit testing and monitoring plans with their permit application, which are incorporated into the Class VI permit. Owners or operators must also periodically review the testing and monitoring plan to incorporate operational and monitoring data and the most recent AoR reevaluation.[132] This review must take place within one year of an AoR reevaluation, following significant changes to the facility, or when required by the Director.

The final rule requires owners or operators to characterize their CO_2 stream as part of their UIC permit applica-

123. UIC Rule, 75 Fed. Reg. at 77250.
124. 40 C.F.R. §146.84(d).
125. UIC Rule, 75 Fed. Reg. at 77250; 40 C.F.R. §146.86.
126. *Id.*
127. UIC Rule, 75 Fed. Reg. at 77251; 40 C.F.R. §146.95.
128. UIC Rule, 75 Fed. Reg, at 77257; 40 C.F.R. §146.88.
129. UIC Rule, 75 Fed. Reg, at 77258; 40 C.F.R. §146.90.
130. UIC Rule, 75 Fed. Reg. at 77259.
131. *Id.*
132. 40 C.F.R. §146.90(j).

tion and throughout the operational life of the injection facility. The details of the sampling process and frequency must be described in the Director-approved, site/project-specific testing and monitoring plan. Analysis of the CO_2 stream for GS projects will provide information about any impurities that may be present and whether such impurities might alter the corrosivity of the injectate. Such information is necessary to inform well construction and the project-specific testing and monitoring plan, and to enable the owner or operator to optimize well operating parameters while ensuring compliance with the Class VI permit.[133] The final rule at 40 C.F.R. §146.89 retains the requirements for continuous monitoring to demonstrate internal mechanical integrity.[134]

The UIC program Director has authority under the SDWA to address potential compliance issues resulting from injection violations in the unlikely event that an emergency or remedial response is necessary. Although EPA anticipates that the need for emergency or remedial actions at GS sites will be rare, the rule requires that emergency and remedial response plans be developed and updated to address such events, and that owners or operators demonstrate that financial resources are set aside to implement the plans if necessary.[135]

Corrosion monitoring is used to provide early warning of well material corrosion that could compromise the well's mechanical integrity. Because of the potential for corrosion of well components if they contact CO_2 in the presence of water, corrosion monitoring is included as a routine part of Class VI well testing. EPA requires quarterly corrosion monitoring at 40 C.F.R. §146.90(c).[136]

Groundwater and geochemical monitoring ensure protection of USDWs from endangerment, preserve water quality, and allow for timely detection of any leakage of CO_2 or displaced formation fluids out of the target formation and/or through the confining layer. Analyzing groundwater quality above the confining layer can reveal geochemical changes that result from leaching or mobilization of heavy metals and organic compounds, or fluid displacement.[137] The final rule, at 40 C.F.R. §146.90(d), retains the requirement for direct groundwater quality monitoring as specified in the site-specific monitoring plan. The number, placement, and depth of monitoring wells will be site-specific and will be based on information collected during baseline site characterization.[138]

Pressure fall-off tests are used to determine if reservoir pressures are tracking predicted pressures and modeling inputs. EPA proposed that owners or operators perform pressure fall-off testing at least once every five years. The final rule, at 40 C.F.R. §146.90(f), requires pressure fall-off testing at least once every five years.

Class VI well owners or operators are required to perform monitoring to track the extent of the CO_2 plume and pressure front.[139] The owner or operator must use direct methods to monitor for pressure changes in the injection zone. Indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole CO_2 detection tools) are required unless the Director determines, based on site-specific geology, that such methods are not appropriate.[140] Additionally, 40 C.F.R. §146.90(g)(2) requires owners or operators to track the position of the CO_2 plume using indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole CO_2 detection tools), unless the Director determines based on site-specific geology, that such methods are not appropriate.[141]

g. Surface Air/Soil Gas Monitoring

Surface air and soil gas monitoring can be used to monitor the flux of CO_2 out of the subsurface, with elevation of CO_2 levels above background levels indicating potential leakage and USDW endangerment. While deep subsurface well monitoring forms the primary basis for detecting threats to USDWs, knowledge of leaks to shallow USDWs is of critical importance, because these USDWs are more likely to serve public water supplies than deeper formations. The decision to use surface monitoring and the selection of monitoring methods will be site-specific and must be based on potential risks to USDWs posed by leaks within the AoR. The final rule at 40 C.F.R. §146.90(h) allows surface air and soil gas monitoring at the discretion of the Director.[142]

EPA concurrent rulemaking concerning GS reporting requirements under the GHG Reporting Program (Subpart RR) builds on UIC requirements with the additional goals of verifying the amount of CO_2 sequestered and collecting data on any CO_2 surface emissions.[143] If a Director requires surface air/soil gas monitoring pursuant to requirements at 40 C.F.R. §146.90(h), and an owner or operator demonstrates that monitoring employed under 40 C.F.R. §§98.440 to 98.449 of Subpart RR meets the requirements at 40 C.F.R. §146.90(h)(3), the Director must approve the use of monitoring employed under Subpart RR.

Class VI well owners or operators are required to develop an emergency and remedial response plan that describes actions to be taken to address events that may cause endangerment to a USDW during the construction, operation, and PISC periods of a GS project. Owners or operators must also periodically update the emergency and remedial response plan to incorporate changes to the AoR or other significant changes to the project.[144] The final rule at §146.94(b) requires that, if an owner or operator obtains evidence of endangerment to a USDW, he or she must:

133. UIC Rule, 75 Fed. Reg. at 77260.
134. *Id.*
135. *Id.*; 40 C.F.R. §§146.94 & .85.
136. *Id.*
137. *Id.*
138. UIC Rule, 75 Fed. Reg. at 77262.
139. 75 Fed. Reg. at 77260, 40 C.F.R. §146.90.
140. 75 Fed. Reg. at 77260.
141. UIC Rule, 75 Fed. Reg. at 77262.
142. UIC Rule, 75 Fed. Reg. at 77263.
143. *See infra* Part III.A.2.
144. UIC Rule, 75 Fed. Reg. at 77272 (codified at 40 C.F.R. §146.94).

(1) immediately cease injection; (2) take all steps reasonably necessary to identify and characterize any release; (3) notify the Director within 24 hours; and (4) implement the approved emergency and remedial response plan.[145]

h. Recordkeeping and Reporting

The final rule at 40 C.F.R. §146.91 requires owners or operators of Class VI wells to submit the results of required periodic testing and monitoring associated with the GS project and requires that all required reports, submittals, and notifications under Subpart H be submitted to EPA in an electronic format. This requirement applies to owners or operators in Class VI primacy states and in states where EPA implements the Class VI program, pursuant to 40 C.F.R. §147.1. All Directors will have access to the data through the EPA electronic data system. The rule identifies the technical information and reports that Class VI owners or operators must submit to the Director to obtain a Class VI permit to construct, operate, monitor, and close a Class VI well. The final decision regarding the appropriateness and acceptability of all owner or operator submissions rests with the Director.

Owners or operators must submit project monitoring and operational data at varying intervals, including semi-annually and prior to or following specific events (e.g., 30-day notifications and 24-hour emergency notifications) as specified at 40 C.F.R. §146.91. Owners or operators also must report the results of mechanical integrity tests and any other injection well testing required by the Director and provide written notification 30 days prior to any planned well workover, stimulation, or test of the injection well. Owners or operators are to electronically submit AoR reevaluation information and all plan amendments, pursuant to 40 C.F.R. §146.84, at a minimum of every five years.[146]

Class VI well owners or operators must retain most operational monitoring data as required under 40 C.F.R. §146.91 for 10 years after the data are collected. The final rule includes the recordkeeping requirements at 40 C.F.R. §144.51(j) and the Class VI-specific recordkeeping requirements at 40 C.F.R. §146.91(f). Owners or operators must retain data collected to support permit applications and data on the CO_2 stream until 10 years after site closure, but the Director has the authority to require the owner or operator to retain specific operational monitoring data for a longer duration of time. Well plugging reports, PISC data, and site closure reports must be kept for 10 years after site closure.[147]

i. Well Plugging, PISC, and Site Closure

Owners or operators of Class VI wells must plug injection and monitoring wells in a manner specified in 40 C.F.R. §146.82. The final rule, at 40 C.F.R. §146.93, also contains requirements for extended, comprehensive post-injection monitoring and site care of GS projects following cessation of injection, until it can be demonstrated that movement of the CO_2 plume and pressure front no longer pose a risk of endangerment to USDWs. The owners or operators must prepare and comply with a Director-approved injection well plugging plan incorporated into the Class VI permit. Owners or operators must submit a notice of intent to plug at least 60 days prior to plugging the well, and must submit, to the Director, a plugging report within 60 days after plugging.[148]

PISC is required during the period after CO_2 injection ceases and prior to site closure. During that period, pursuant to 40 C.F.R. §146.93, the owner or operator must continue monitoring to ensure USDW protection from endangerment. The requirement to maintain and implement the approved PISC and site closure plan is directly enforceable, regardless of whether the requirement is a condition of the Class VI permit.[149] Upon cessation of injection, owners or operators of Class VI wells either submit an amended PISC and site closure plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the plan is needed. The regulations include a default 50-year PISC time frame but allows the Director to shorten or lengthen the PISC time frame during the PISC period based on site-specific data, pursuant to requirements at 40 C.F.R. §146.93(b); and gives the Director discretion to approve during the permitting process that an alternative PISC time frame is appropriate pursuant to requirements at 40 C.F.R. §146.93(c).[150]

Following a determination under 40 C.F.R. §146.93 that the site no longer poses a risk of endangerment to USDWs, the Director may approve site closure, and the owner or operator would close site operations. EPA proposed site closure activities similar to those for other well classes. These include plugging all monitoring wells; submitting a site closure report; and recording a notation on the deed to the facility property or other documents that the land has been used to sequester CO_2. Site closure would proceed according to the approved PISC and site closure plan as specified at 40 C.F.R. §146.93(d) through (h).[151]

A Class VI permit does not necessarily protect operators from liability based on the Clean Air Act (CAA),[152] the Resource Conservation and Recovery Act (RCRA)[153] or the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund).[154] EPA indicates that the concentration of impurities in the waste is expected to be low, but in the SDWA, the Agency leaves

145. UIC Rule, 75 Fed. Reg. at 77273.
146. UIC Rule, 75 Fed. Reg. at 77265.
147. *Id.*

148. UIC Rule, 75 Fed. Reg. at 77266.
149. *Id.*
150. UIC Rule, 75 Fed. Reg. at 77266-68.
151. *Id.*
152. 42 U.S.C. §§7401-7671q, ELR Stat. CAA §§101-618.
153. 42 U.S.C. §§6901-6992k, ELR Stat. RCRA §§1001-11011.
154. 42 U.S.C. §§9601-9675, ELR Stat. CERCLA §§101-405.

it to the permit holder to determine whether CO_2 injection is hazardous under RCRA or CERCLA.[155]

Ultimately, the SDWA is too limited in its scope to resolve the legal issues that will arise if a large-scale CCS program is to develop. A more comprehensive statute is needed that deals with the long-term liability issues. Many in the coal-burning electric power industry fear that a failure to shield CCS projects from RCRA/CERCLA liability will prevent their commercialization.[156] In addition, operators have potential liability based on tort law.[157] EPA's UIC rule under the SDWA affects state regulation, but the role of the states cannot easily be preempted, because legal issues concerning sequestration will involve property, tort, and contract law that are controlled by state law.[158]

2. Monitoring and Reporting

EPA also seeks to impose monitoring and reporting requirements on sequestration operations based on its authority under CAA §§114 and 208.[159] The Agency promulgated a final regulation to implement a mandatory GHG emissions reporting program on October 30, 2009.[160] The regulation became effective on January 1, 2010, and the first reports were due on March 31, 2011.[161] It applies to fossil fuel suppliers, industrial gas suppliers, and direct GHG emitters if they emit 25,000 metric tons of GHGs or more per year expressed as CO_2 equivalent (CO_2e).[162] Some facilities in identified categories must report, even if emissions are below 25,000 tons of CO_2e. Facilities within listed categories include electric power plants subject to the Acid Rain Program, including those owned by the federal and municipal governments and those located in Indian country.[163]

On December 1, 2010, EPA promulgated a final rule mandating reporting of GHGs from carbon injection and GS and estimates monitoring and reporting will cost about $300,000 per year for each site.[164] Owners or operators subject to the December 10, 2010, GS rule are required to comply with the reporting rule, at 40 C.F.R. Part 98, Subpart RR, which requires GS facilities to collect data on the amount injected in a quarter and annually. All other facilities that inject CO_2 underground are subject to Part 98, Subpart UU.[165] Research and development (R&D) projects are exempt from the reporting requirements of 40 C.F.R. Part 98, Subpart RR, if they meet eligibility requirements. Most of the existing CCS projects would appear to be R&D projects that are exempt from the need to comply with Subpart RR. However, they are not exempted from other potentially applicable Part 98 reporting requirements, including Subpart UU requirements.[166]

Subpart RR establishes reporting requirements for facilities that inject a CO_2 stream for long-term containment into a subsurface geologic formation, including sub-seabed offshore formations.[167] These facilities are required to develop and implement a site-specific measurement, reporting, and verification (MRV) plan, which, once approved by EPA (in a process separate from the UIC permitting process), would be used to verify the amount of CO_2 sequestered and to quantify emissions in the event that injected CO_2 leaks to the surface. EPA designed the reporting requirements under Subpart RR with consideration of the requirements for Class VI well owners or operators in Subpart H of Part 146 of the UIC GS rule. Subpart RR builds on the Class VI requirements to verify the amount of CO_2 sequestered and to collect data on any CO_2 surface emissions from GS facilities as identified under Subpart RR of Part 98.[168] This data will assist EPA when making policy decisions under CAA §§111 and 112 related to the use of CCS for mitigating GHG emissions. In combination with data from other subparts of the GHG Reporting Program, data from Subpart UU and Subpart RR will allow EPA to track the flow of CO_2 across the CCS system. EPA will be able to reconcile Subpart RR data on CO_2 received with CO_2 supply data in order to understand the quantity of CO_2 supply that is geologically sequestered.[169]

EPA realizes that there are similar data elements that must be reported pursuant to requirements in the UIC GS rules and those required to be reported under Subpart RR. Owners or operators subject to both regulations must report the amount (flow rate) of injected CO_2. The UIC Class VI and Subpart RR rules differ not only in purpose, but in the specific requirements for the measurement unit and collection/reporting frequency. The UIC Class VI rule requires that owners or operators report information on the CO_2 stream to ensure appropriate well siting, construction, operation, monitoring, post-injection site care, site closure, and financial responsibility to ensure protection

155. *See infra* Part III.C.
156. *Western Businesses Warn EPA Liability Rules May Sink CCS Projects*, XXVI Envtl. Pol'y Alert 22:26 (Nov. 5, 2009).
157. *See generally* Alexandra B. Klass & Elizabeth J. Wilson, *Climate Change and Carbon Sequestration: Assessing a Liability Regime for Long-Term Storage of Carbon Dioxide*, 58 Emory L.J. 103 (2008); Peter S. Glaser et al., *Global Warming Solutions: Regulatory Challenges and Common Law Liabilities Associated With the Geological Sequestration of Carbon Dioxide*, 6 Geo. J. L. & Pub. Pol'y 429 (2008).
158. Elizabeth J. Wilson & Mark A. de Figueiredo, *Geologic Carbon Dioxide Sequestration: An Analysis of Subsurface Property Law*, 36 ELR 10114 (Feb. 2006).
159. 42 U.S.C. §§7414 & 7542.
160. *Mandatory Reporting of Greenhouse Gases*, 74 Fed. Reg. 56260 (Oct. 30, 2009). The reporting program was expanded with additional requirements in 2010 (75 Fed. Reg. 39736 (July 12, 2010)) [hereinafter GHG Reporting].
161. *Id.*
162. CO_2e: The amount of CO_2 by weight emitted into the atmosphere that would produce the same estimated radiative forcing as a given weight of another radiatively active gas. CO_2e is computed by multiplying the weight of the gas being measured (for example, methane) by its estimated global warming potential (which is 21 for methane). "Carbon equivalent units" are defined as CO_2e multiplied by the carbon content of CO_2 (i.e., 12/44). Energy Information Administration, Glossary, Carbon Dioxide Equivalent, http://www.eia.doe.gov/glossary/glossary_c.htm (last visited July 3, 2011).
163. GHG Reporting, 74 Fed. Reg. at 56264.
164. Steven Cook, *EPA Proposes Greenhouse Gas Reporting for Oil and Gas Wells, Carbon Storage, HFCs*, 41 Env't Rep. (BNA) 659 (Mar. 26, 2010).
165. UIC Rule, 75 Fed. Reg. at 77235.
166. GHG GS, 75 Fed. Reg. at 75064-65.
167. *Id.*
168. UIC Rule, 75 Fed. Reg. at 77236.
169. UIC Rule, 75 Fed. Reg. at 77235.

of USDWs. Under Subpart RR, owners or operators must report the amount (flow rate) of injected CO_2 for the mass balance equation that will be used to quantify the amount of CO_2 sequestered by a facility. However, compliance with the reporting requirements of Subpart RR will meet most of the reporting requirements of UIC Class VI, as shown in Table II-1 of the rule. EPA is working to better integrate data management between the UIC and GHG Reporting Programs to ensure that data needs are harmonized and the burden to regulated entities is minimized.[170] On March 1, 2011, EPA announced it was extending the deadline for reporting GHG emissions under its rule at 40 C.F.R. Part 98 until September 30, 2011, in order to allow more time to finalize its online electronic reporting platform.[171]

3. Administration of the UIC Program

EPA administers the UIC program in 10 states.[172] The UIC program regulates underground injection activities including EOR, but it does not encompass the underground storage of natural gas.[173] The Energy Independence and Security Act of 2007 gave EPA the explicit authority under the SDWA to regulate injection and geologic sequestration of CO_2.[174] Governors from oil and gas producing states did not want federal regulation of CO_2 injection, because they do not want interference with the use of CO_2 to force natural gas and petroleum to the surface that is regulated by the oil and gas producing states. These injection operations are small compared to what would be required to sequester CO_2 emissions from fossil-fueled electric power plants.[175]

EPA administers the SDWA's UIC program on Indian lands based on 18 U.S.C. §1151, which defines Indian country to include reservations, Indian allotments, and dependent Indian communities. The first two categories have been defined with reasonable precision, but the third category is somewhat ambiguous and has been applied to include lands owned by non-Indians.[176] Sequestration activities in the West could easily involve lands that are subject to Indian law. Determining whether land in Indian country is subject to state or EPA jurisdiction requires using the tests established by judicial decisions.[177] The U.S. Court of Appeals for the Tenth Circuit revisited this issue when it ruled on April 17, 2009, that a non-Indian mining corporation that intended to operate a uranium mine in New Mexico was subject to regulation by EPA because the land was within a dependent Indiana community.[178] The Tenth Circuit, sitting en banc, rejected EPA's subjective community reference test, holding that it was superseded by the U.S. Supreme Court's decision in *Alaska v. Native Village of Venetie Tribal Government*.[179] The proper test to determine whether lands are part of Indian country and thus subject to tribal jurisdiction focuses only on the lands in question (rather than the surrounding area) and requires the lands to be: (1) set aside by the U.S. Congress; and (2) superintended by the federal government. However, the Tenth Circuit muddied the waters by suggesting EPA may want to use its "considerable discretion" to employ some other test to determine jurisdiction over SDWA issues, noting:

> While §1151 does its job of assigning prosecutorial authority over particular tracts of land tolerably well, it is perhaps unsurprising that it may prove less satisfactory when it comes to allocating regulatory authority over aquifers running beneath those lands. . . . Someday, EPA may seek to avoid these difficulties by unhitching its UIC permitting authority from §1151.[180]

Thirty-three states and three territories have been given "primacy," or primary enforcement authority, and seven states have partial authority to administer the UIC program based on the program found in SDWA §1421(b).[181] To administer the UIC program, states must apply to EPA for primacy approval and demonstrate: (1) state jurisdiction over underground injection projects; (2) that their state regulations are at least as stringent as those promulgated by EPA (e.g., permitting, inspection, operation, monitoring, and recordkeeping requirements); and (3) that the state has the necessary administrative, civil, and criminal enforcement penalty remedies pursuant to 40 C.F.R. §145.13.[182] EPA's Administrator must review and approve or disapprove or disapprove part of a state's primacy application. This determination is based on EPA's mandate under the SDWA as implemented by UIC regulations established in 40 C.F.R. Parts 144 through 146, and must be made by a rulemaking.[183]

Under SDWA §1422, states must demonstrate that their proposed UIC program meets the statutory requirements under §1421 and that their program contains requirements that are at least as stringent as the minimum federal requirements provided for in the UIC regulations to ensure protection of USDWs. In the December 10, 2010, final UIC rule, and in accordance with SDWA §1422, all

170. *Id.*
171. U.S. EPA, *Final Regulation Extending the Reporting Deadline for Year 2010 Data Elements Required Under the Mandatory Reporting of Greenhouse Gases Rule*, 76 Fed. Reg. 14812 (Mar. 18, 2011).
172. GAO, *supra* note 45, at 15.
173. 40 C.F.R. §§140-146.
174. Pub. L. No. 110-140 (Dec. 19, 2007).
175. *Oil, Natural Gas Producing States Offer Strategy for Carbon Capture*, XVI Clean Air Rep. (Inside EPA) 6:27 (Mar. 24, 2005).
176. *See, e.g.*, United States v. Mazurie, 419 U.S. 544, 546-47 (1975).
177. *See, e.g.*, Alaska v. Native Village of Venetie Tribal Government, 522 U.S. 520 (1998).
178. Hydro Resources, Inc. v. EPA, 562 F.3d 1249, *vacated by* 608 F.3d 1131 (10th Cir. 2010). No one lived on the land; taxes were paid to McKinley County, New Mexico; all government services were provided by New Mexico. However, the land was six miles from a small Navajo town, which was sufficient for EPA to rule that the land was subject to tribal jurisdiction, and the court upheld the decision.
179. 608 F.3d at 1166.
180. *Id.*
181. 42 U.S.C. §300h(b) (West 2010). This section mandates that EPA develop minimum federal requirements for state UIC primary enforcement responsibility, or primacy, to protect underground drinking water supplies. A complete list of the primacy agencies in each state is available at http://www.epa.gov/safewater/uic/primacy.html (last visited July 21, 2011).
182. UIC Rule, 75 Fed. Reg. at 77240.
183. *Id.*

Class VI state programs must be at least as stringent as the minimum federal requirements.[184]

EPA's practice has been to not accept UIC primacy applications from states for individual well classes. If a state wanted primacy, it would need to accept it for all well classes. However, the Agency will allow independent primacy for Class VI wells under §145.1(i) of the final rule. EPA will not consider applications for independent primacy for any other injection well class under SDWA §1422 other than Class VI, nor will the Agency accept the return of portions of existing §1422 programs. EPA will continue to process primacy applications for Class II injection wells under the authority of §1425 of the SDWA. The Agency plans to provide guidance to states applying for Class VI primacy under §1422 of the SDWA and to assist UIC Directors evaluating permit applications.[185]

The final UIC rule establishes a federal Class VI primacy program in states that choose not to seek primacy for the Class VI portion of the UIC program within the approval time frame established under §1422(b)(1)(B) of the SDWA.[186] States will have 270 days following final promulgation of the GS rule to submit a complete primacy application that meets the requirements of §§145.22 or 145.32. States must follow the requirements found in 40 C.F.R. §145.23(f). If a state does not submit a complete application during the 270-day period, or if EPA has not approved a state's Class VI program submission, then EPA will establish a federal UIC Class VI program in that state after the application period closes.[187] States may not issue Class VI UIC permits until their Class VI UIC programs are approved. Until a state has an approved Class VI program, EPA will establish and implement a Class VI program, and the appropriate EPA Region will issue Class VI permits. In June 2011, EPA promulgated "Draft Underground Injection Control (UIC) Program Class VI Primacy Application and Implementation Manual for State Directors" to assist states in obtaining primacy.[188]

The December 10, 2010, rule requires the Director of Class VI programs approved before December 10, 2011, to notify owners or operators of any Class I wells previously permitted for the purpose of geologic sequestration or Class V experimental technology wells no longer being used for experimental purposes that will continue injection of CO_2 for the purpose of GS that they must apply for a Class VI permit pursuant to requirements at §146.81(c) within one year of December 10, 2011.[189]

4. Fiscal Responsibility

EPA requires owners or operators to demonstrate and maintain financial responsibility, as specified in regulations at 40 C.F.R. §146.85, for performing corrective action on wells in the AoR, injection well plugging, PISC and site closure, and emergency and remedial response. Financial assurance is typically demonstrated through: (1) third-party instruments, including surety bond, financial guarantee bond or performance bond, letters of credit (the above third-party instruments must also establish a standby trust fund), and an irrevocable trust fund; and (2) self-insurance instruments, including the corporate financial test and the corporate guarantee.[190] EPA reevaluated the current minimum Tangible Net Worth (TNW) requirement of $10 million used in the Class I regulations and will recommend a TNW threshold for Class VI wells in guidance to be issued in 2011. The financial responsibility guidance will also include a recommended cost estimation methodology to assist owners or operators of Class VI wells, and will provide examples of cost considerations and activities that may need to be performed to satisfy the requirements of the current rule.[191]

Once an owner or operator has met all regulatory requirements under Part 146 for Class VI wells and the Director has approved site closure pursuant to requirements at §146.93, the owner or operator will generally no longer be subject to enforcement under §1423 of the SDWA for noncompliance with UIC regulatory requirements. However, an owner or operator may be held liable for regulatory noncompliance under certain circumstances, even after site closure is approved under §146.93, under §1423 of the SDWA for violating §144.12, such as where the owner or operator provided erroneous data to support approval of site closure.[192] An owner or operator, however, may always be subject to an order the Administrator deems necessary to protect the health of persons under §1431 of the SDWA after site closure if there is fluid migration that causes or threatens imminent and substantial endangerment to a USDW. The order may include commencing a civil action for appropriate relief. If the owner or operator fails to comply with the order, they may be subject to a civil penalty for each day in which such violation occurs or failure to comply continues. EPA does not have authority to transfer liability from one entity (i.e., owner or operator) to another.[193]

Because of the pressure exerted by the compressed CO_2 and the large quantities that will need to be sequestered, a release could have catastrophic consequences to the health of humans and animals. The SDWA's financial responsibility requirements are only a limited solution to the issue of the long-term liability of those participating in CCS projects. Unless a broad indemnification program is created to limit the risk associated with unforeseen environmental consequences from CCS, it is unlikely that major sequestration projects will proceed.

184. UIC Rule, 75 Fed. Reg. at 77241.
185. UIC Rule, 75 Fed. Reg. at 77242.
186. 40 C.F.R. §145.21(h).
187. UIC Rule, 75 Fed. Reg. at 77242.
188. *Available at* http://water.epa.gov/type/groundwater/uic/class6/upload/epa816d11001.pdf (last visited July 6, 2011).
189. 40 C.F.R. §145.23(f)(4).
190. UIC Rule, 75 Fed. Reg. at 77268.
191. UIC Rule, 75 Fed. Reg. at 77269.
192. UIC Rule, 75 Fed. Reg. at 77272.
193. *Id.*

It should be noted that indemnification was a key element of the Price-Anderson Act's insurance program associated with the nuclear industry, which has evolved into an industry-funded no-fault insurance program.[194] Price-Anderson applies to a well-capitalized industry with more than 100 units and provides financial protection for liability that may develop in a short time. The number of industry participants allows for a manageable distribution of risk-related costs in the event of the worst-case event.[195] The Price-Anderson Act, however, may not be a useful model for CCS projects, because during the initial development of a technology there are few participants, CCS projects may not have a significant cash flow, and their potential liability will continue for a century or more. They will require indemnification by the government if investment is to be made, which will necessitate having a definable down-side risk for investors. If technology development is to be implemented by corporations having substantial capital to invest, it will be necessary to avoid unlimited development-related risks that effectively place the company's net worth at risk as a necessary precondition to project approval and implementation.

The Southern Company, Duke Energy, the Environmental Defense Fund, and the Zurich Insurance Company have developed an insurance plan that they are urging Congress to codify. It calls for a four-tiered liability program for CCS operations. Under the first tier, CCS operators would be liable for $50 million or more as determined by Congress. The second tier would be an industrywide pool that would have a liability of $12.5 million per entity that would become a substantial additional source of coverage as CCS operations grow. The third tier would consist of a government-funded insurance program that would have a lifetime cap of $300 million to $900 million per operator. The fourth tier would require the operator to cover any liabilities that exceeded the first three tiers of coverage.[196]

B. The CAA

New pulverized coal plants must meet the new source performance standards (NSPS) for coal-fired power plants.[197] These requirements are based on 1979 regulations.[198] NSPS also apply to modifications that increase the amount of air pollution emitted or that results in the emission of any air pollutant not previously emitted.[199] NSPS apply to source categories that contribute significantly to "air pollution which may reasonably be anticipated to endanger public health or welfare."[200] Electric power plants and separate sequestration facilities are subject to §111 requirements, but NSPS covering GHGs have not yet been promulgated. EPA released a notice of proposed rulemaking in March 2011 to update its NSPS for electric utility steam-generating units and plans to take final action in November 2011.[201] EPA also plans to regulate air toxics from electric power plants and sent a proposed rule to the White House for review on February 19, 2011.[202] This rule could force coal-fired plants to install scrubber technology to control acid gases, which could force many plants to close.[203] In attainment areas, which are areas that meet the national ambient air quality standards (NAAQS), new or modified major sources must comply with the more stringent prevention of significant deterioration (PSD) requirements that include the need for a construction permit that is individually negotiated for each applicant.[204]

A typical configuration for a new power plant burning low-sulfur western coal would have low nitrogen oxide (NO_x) burners, limestone injection into the furnace, particulate collection, a high-efficiency advanced selective catalytic NO_x removal system, spray dry absorber flue gas desulphurization systems, and a fabric filter. This pollution control technology produces NO_x emissions that are significantly lower than natural gas combined-cycle technology using dry low-NO_x combustion, which is usually a reverse air pulse jet fabric filter.[205] IGCC technology would presumably also have higher NO_x emissions than a state-of-the-art pulverized coal plant. The controls on high-sulfur fuel are somewhat different and use wet scrubber and wet electrostatic precipitator technology. These emission controls have no material effect on CO_2 emissions, but they do increase the cost of coal-fired electric power generation.

As part of the PSD construction permit process, projects must have their environmental impacts assessed.[206] The PSD process includes determining the appropriate technology to require an applicant to use to comply with the CAA §165(a)(4) requirement mandating the use of the best available control technology (BACT). BACT is defined in CAA §169(3) to include process changes, fuel substitution, add-on controls, and any other available methods to obtain the maximum degree of emission reduction, after considering economic impacts and costs.[207] Environmentalists are

194. 42 U.S.C. §§2210 et seq.
195. 42 U.S.C. §2210.
196. Kate Williams, *Coalition Offers Deal on CCS Liability for Future Climate Change Bill*, XXI Clean Air Rep. (Inside EPA) 16:27 (Aug. 5, 2010).
197. CAA §111, 42 U.S.C. §7411.
198. Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After Aug. 17, 1971, 40 C.F.R. pt. 60, subpts. D, Da (2010).
199. CAA §111(a)(4), 42 U.S.C. §7411(a)(4).
200. *Id.* at (b)(1)(A).
201. *See* http://www.reginfo.gov/public/do/eAgendaViewRule?pubid=201010&RIN= 2060-AQ37 (last visited July 26, 2011).
202. *See* Andrew Childers, *EPA Sends Hazardous Air Pollutant Rule for Power Plants to White House for Review*, 42 Env't Rep. (BNA) No. 8, 366 (Feb. 25, 2011).
203. Nick Juliana & Stuart Parker, *Utility MACT May Prompt Broad Need for "Scrubbers," Boosting Cost Fears*, XXII Clean Air Rep. (Inside EPA) 6:3 (Mar. 17, 2011).
204. CAA §165, 42 U.S.C. §7475.
205. *See* Bielawski et al., *supra* note 13, at 7.
206. For an overview of the NSR program, see Arnold W. Reitze Jr., *New Source Review: Should It Survive?*, 34 ELR 10673 (July 2004).
207. CAA §169(3), 42 U.S.C. §7479(3). A pulverized coal plant equipped with pulse jet fabric filters can achieve 99.9% particulate removal efficiencies and meet a 0.015 pound per million British thermal units (lb./MBtu) standard. SO_2 removal up to 95% can be achieved by using a wet scrubber, which allows an emission standard of 0.12 lb./MBtu to be met. Conventional coal-burning power plants combust their fuel at about 3,000 degrees Fahrenheit to produce high-pressure steam that is utilized in a high-pressure turbine. However, low NO_x burners may be used to keep flame temperatures at about 2,500 degrees Fahrenheit. This limits NO_x formation from the nitrogen in

currently pressuring EPA to require consideration of CCS for CO_2 sources as part of the BACT determination, which is one of the requirements imposed on applicants for a construction permit.[208]

In nonattainment areas, which are areas that do not meet the NAAQS for a pollutant that will be emitted, a project is subject to new source review (NSR).[209] Because CO_2 is not a criteria pollutant, there can be no CO_2 nonattainment areas, but areas that are nonattainment for other pollutants may be subject to controls for CO_2.[210] In nonattainment areas, CAA §173(a)(2) requires the lowest achievable emission rate (LAER) to be achieved, which is similar to but more stringent than BACT. LAER is based on the most stringent standard in any state implementation plan (SIP) or the most stringent standard that is achievable, whichever is more stringent.[211] For determining the technology that qualifies as BACT/LAER, EPA usually uses a "top-down" analysis, which at a minimum requires compliance with any applicable NSPS.[212] BACT/LAER are source-specific and allow the permitting authority to impose more stringent requirements on a permit applicant than otherwise would be imposed by the CAA.[213] The primary guidance concerning BACT/LAER requirements is EPA's 1990 New Source Review Workshop Manual.[214]

The PSD process, if applicable, applies to "each pollutant subject to regulation under this chapter emitted from, or which results from, such facility," but in nonattainment areas, a new or modified major source must control any pollutant that is subject to an NSPS.[215] Air pollutant is defined broadly in CAA §302(g). In addition to PSD/NSR requirements, states may impose additional standards pursuant to CAA §116. All states have been delegated the authority to run their nonattainment NSR program; most states have been delegated the authority to run their PSD programs.[216]

An issue of concern has been whether climate change may be addressed in the PSD/NSR process. On June 2, 2008, EPA's independent Environmental Appeals Board (EAB) rejected a challenge to a refinery expansion project for tar sands processing in Illinois that did not include GHG controls.[217] Similarly, the EAB issued an order that it would not consider CO_2 emissions in the air permit case of *In re Northern Michigan University Ripley Heating Plant*.[218] Other decisions have indicated that CO_2 emissions are to be considered to be part of the PSD permit process.[219]

On December 18, 2008, EPA's Administrator Stephen Johnson issued a memorandum that restated EPA's position that CO_2 is not a pollutant under the CAA, because it is not subject to any regulation that requires actual control of emissions, therefore the Agency is not required to consider CO_2 emissions when it issues permits under the PSD program.[220] However, on February 17, 2009, EPA Administrator Lisa Jackson said the Agency would take a new look at whether CO_2 from power plants should be regulated.[221] This led to a proposed rule to reconsider EPA's position being published in the *Federal Register* on October 7, 2009.[222]

In 2007, the Supreme Court held that GHGs, including CO_2, are air pollutants based on the definition found in CAA §302(g).[223] But even with this holding, EPA had to make an endangerment finding if it was to regulate GHGs. On December 15, 2009, EPA promulgated an endangerment finding that CO_2, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride in the atmosphere threaten public health and welfare, and motor vehicles contribute to GHG pollution.[224] On May 7,

the air, while nitrogen in the coal, which is responsible for approximately 80% of the NO_x generated from these facilities, is controlled through a fuel-rich condition using air injection to control stoichiometry. The pollution control devices for NO_x and particulate control will also remove 90% of the mercury. *See Acid Rain; Nitrogen Oxides Emissions Reduction Program*, 61 Fed. Reg. 67112 (Dec. 19, 1996) (codified at 40 C.F.R. pt. 76).

208. *Activists Urge EPA to Set GHG Performance Standard to Boost Use of CCS*, XXVII Envtl. Pol'y Alert (Inside EPA) 15:21 (July 28, 2010).

209. EPA frequently uses NSR to mean both the PSD and NSR program.

210. Environmentalists are seeking to have CO_2 declared a criteria pollutant. *Activists Petition EPA for CO_2 NAAQS Citing Insufficient Climate Action*, XX Clean Air Rep. (Inside EPA) 25:4 (Dec. 10, 2009).

211. CAA §171(3), 42 U.S.C. §7501(3). *See also* Sur Contra la Contaminacion v. EPA, 202 F.3d 443, 30 ELR 20358 (1st Cir. 2000).

212. CAA §§169(3), 171(3), 42 U.S.C. §§7479(3), 7501(3) (West 2010).

213. CAA §111(a)(3) & (4), 42 U.S.C. §7411(a)(3) & (4) (West 2010).

214. U.S. EPA, New Source Review Manual: Prevention of Deterioration and Nonattainment Area Permitting (1990), *available at* http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf.

215. CAA §§165(a)(4), 171(3), 42 U.S.C. §§7475(a)(4), 7501(3).

216. 40 C.F.R. §§51.165 & 51.166 (2010).

217. In re Conoco Phillips Co., EPA EAB PSD Appeal No. 07-02 (review denied June 2, 2008). The case was a win for the project's opponents, because the EAB remanded the permit to the state to review emission limitations for conventional pollutants. *See EAB Ruling May Bolster Activists' Bid to Target Tar Sands Refining*, XIX Clean Air Rep. (Inside EPA) 12:23 (June 12, 2008).

218. In re Northern Michigan University Ripley Heating Plant, EAB, PSD Appeal No. 08-02 (Feb. 18, 2009). *Activists Plan Shift to State Suits if EAB Rejects CO_2 Permit Limits*, XXV Envtl. Pol'y Alert (Inside EPA) 22:12 (Oct. 22, 2008).

219. *See, e.g.*, In re Deseret Power Electric Cooperative, EPA PSD Appeal No. 07-03 (Nov. 13, 2008). EPA's Region 8 granted a PSD permit to the Deseret Power Electric Cooperative's proposed new waste-coal-fired facility near Bonanza, Utah, despite its potential for increasing CO_2 emissions. The granting of the permit was appealed by the Sierra Club to EPA's EAB, which on November 13, 2008, remanded the permit to EPA's Region 8 to reconsider whether to impose CO_2 BACT limits and to develop an adequate record for its decision. The EAB found that the Region wrongly believed its discretion was limited by historical Agency interpretation. The EAB suggested the Region consider whether the public and the Agency would benefit from having the phrase "subject to regulation under the Act" interpreted through a regulation having nationwide scope rather than through this specific permitting proceeding. The EAB did not rule on a Sierra Club argument that §821 of the CAA Amendments of 1990, Pub. L. No. 101-549, 104 Stat. 2399, 2699 (1990), which is not codified in the CAA, but which requires monitoring and reporting of CO_2 emissions, is a regulation under the CAA.

220. EPA's Interpretation of Regulations That Determine Pollutants Covered by Federal Prevention of Significant Deterioration (PSD) Permit Program (a.k.a. Johnson Memo), 73 Fed. Reg. 80300 (Dec. 31, 2008) (to be codified at 40 C.F.R. pt. 52).

221. *Jackson Agrees to Take Fresh Look at Last-Minute CO_2 Permit Memo*, XX Clean Air Rep. (Inside EPA) 4:26 (Mar. 5, 2009); Steven D. Cook, *EPA Tells Appeals Board It Wants Review of Gasification for New Mexico Power Plant*, 40 Env't Rep. (BNA) 984 (May 1, 2009).

222. Prevention of Significant Deterioration: Reconsideration of Interpretation of Regulations That Determine Pollutants Covered by the Federal PSD Permit Program, 74 Fed. Reg. 51535 (Oct. 7, 2009).

223. Massachusetts v. EPA, 549 U.S. 497, 37 ELR 20075 (2007).

224. U.S. EPA, Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66495 (Dec. 15, 2009).

2010, EPA and the U.S. Department of Transportation's (DOT's) National Highway Traffic Safety Administration promulgated their joint final rule to regulate GHG emissions from light-duty vehicles, as well as new fuel economy requirements beginning in January 2011.[225] Thus, when light-duty vehicles were subjected to GHG emissions limits, GHGs became regulated pollutants under the CAA, which makes sources of GHGs subject to regulation under many provisions of the CAA, including the CAA's PSD/NSR requirements and potentially under other environmental laws.

In anticipation of a final rule on mobile source GHG emissions, on October 27, 2009, EPA promulgated proposed regulations, called the Tailoring Rule, to modify the regulations applicable to the PSD program and the Subchapter V operating permit program concerning requirements for regulating GHGs.[226] On June 3, 2010, EPA promulgated its final Tailoring Rule.[227] EPA decided to subject GHG sources to the PSD permitting program in three steps. Beginning January 2, 2011, sources currently subject to the PSD permitting process must comply with the GHG regulatory program if they are new or are modified to increase emissions above existing significance levels and have total GHG emissions of 75,000 tons per year (tpy) or more on a CO_2e basis. Certain Title V operating permits issued after January 2, 2011, also must comply with GHG requirements.

No sources will be subject to the CAA permitting requirement solely due to GHG emissions until the second step, which begins July 1, 2011. PSD permitting requirements will apply to new construction with GHG emissions of at least 100,000 tpy, even if they do not exceed the permit threshold for other pollutants. For existing sources, modification will trigger PSD requirements if they emit 75,000 tpy of GHGs, even if they do not significantly increase emissions of other pollutants.[228] This position may not be consistent with the language of the CAA and may be affected by pending litigation.[229] Facilities that do not have an operating permit will be required to obtain one if emissions exceed 100,000 tpy of CO_2e.[230] The third step involves another rulemaking to conclude no later than July 1, 2012, to possibly apply permitting programs to additional sources, but EPA does not plan to require permits for sources with CO_2 emissions below 50,000 tpy until at least April 30, 2016.[231] EPA's Tailoring Rule may not survive judicial review, because its 75,000 and 100,000 tpy triggers for GHGs conflict with CAA §502, which imposes a 100 tpy trigger, and the PSD program's §169(a), which defines "major emitting facility" as a 100 or 250 tpy source.[232]

To assist state and local permitting authorities, EPA, on November 10, 2010, made available "PSD and Title V Permitting Guidance for Greenhouse Gases."[233] The guidance provides that PSD and Title V apply to GHG emissions, and BACT determinations will be made by states. EPA does not prescribe GHG BACT requirements, but emphasizes the importance of BACT options that improve energy efficiency.[234] It does say that CCS, at this time, is unlikely to be considered a BACT requirement. Permits that are effective prior to January 2, 2011, do not need to include GHG provisions. EPA expects permitting authorities to continue to use the five-step, top-down analysis for determining the applicable BACT technology.[235] EPA has produced "white papers" that provide basic technical information useful for BACT analysis, but they do not define BACT. The papers cover seven industrial sectors: electric generating units; large industrial/commercial/institutional boilers; pulp and paper; cement; iron and steel; refineries; and nitric acid plants.[236] On March 25, 2011, EPA issued "PSD and Title V Permitting Guidance for Greenhouse Gases." It replaces the November 2010 guidance and contains a limited number of clarifying edits.[237] EPA did not make any changes to the November 2010 guidance that required permitting agencies to consider CCS and fuel switching as options under a PSD review to determine BACT.[238]

EPA is motivated to increase the GHG threshold for major sources because GHG regulations will significantly increase applications for PSD permits. The existing PSD program issues 280 permits per year, whereas under new GHG regulations, EPA and the states could be required to handle permit applications from 41,000 new and modified facilities per year in 2010. In addition, EPA is concerned that one year after GHG regulations for mobile sources become effective, six million sources would be required to submit CAA Subchapter V operating permit applications without the Tailoring Rule. These permits would need to be issued within 18 months after receipt of a complete application. In addition, GHG limitations would need to be added to the existing 14,700 Subchapter V operating

225. U.S. EPA & U.S. DOT, Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule, 75 Fed. Reg. 25523 (May 7, 2010).
226. U.S. EPA, Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 74 Fed. Reg. 55291, 55300 (proposed Oct. 27, 2009).
227. U.S. EPA, Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule: Final Rule, 75 Fed. Reg. 31513 (June 3, 2010) [hereinafter Tailoring Rule].
228. Tailoring Rule, 75 Fed. Reg. at 31523.
229. *See* Victoria Finkle, *Little-Noticed Suit Over Permit "Trigger" May Be Test for Climate Rules*, XXII Clean Air Rep. (Inside EPA) 6:11 (Mar. 17, 2011).
230. Tailoring Rule, 75 Fed. Reg. at 31524.
231. Tailoring Rule, 75 Fed. Reg. at 31525.
232. 42 U.S.C. §§7479, 7661a.
233. U.S. EPA, Clean Air Act Permitting for Greenhouse Gases: Guidance and Technical Information (Fact Sheet), *available at* http://www.epa.gov/nsr/ghgdocs/ghgpermittingtoolsfs.pdf.
234. Steven D. Cook, *EPA Issues Guidance to States, Localities on Controls for Greenhouse Gas Sources*, 41 Env't Rep. (BNA) 2504 (Nov. 12, 2010).
235. *Id.*
236. *See, e.g.*, U.S. EPA, Office of Air and Radiation, *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions From Coal-Fired Electric Generating Units* (Oct. 2010), *available at* http://www.epa.gov/nsr/ghgdocs/electricgeneration.pdf.
237. PSD and Title V Permitting Guidance for Greenhouse Gases (Mar. 2011), *available at* http://www.epa.gov/nsr/ghgpermittingguidance.pdf.
238. *Id.*

permits.[239] For this reason, states are urging EPA to delay implementation of its Tailoring Rule.[240]

EPA's effort to limit the number of potential permits using the proposed Tailoring Rule would not affect states that have PSD programs that are part of an approved SIP. They must continue to use the 100/250-tpy threshold trigger until an SIP revision is approved. Under the Tailoring Rule or the CAA's 100/250-tpy trigger, existing sources would be subject to permit requirements for any increase in emissions, because there is no regulatory "significance level" for CO_2 that limits the applicability of the PSD program. Thus, any increase in emissions is considered significant.[241]

EPA, on April 2, 2010, promulgated its regulatory interpretation concerning the pollutants covered by the CAA.[242] EPA decided to continue applying the Agency's existing interpretation of 40 C.F.R. §52.21(b)(50) and the parallel provision in 40 C.F.R. §51.166(b)(49) found in its PSD Interpretive Memo. However, EPA refined its interpretation to establish that PSD permitting requirements apply to a newly regulated pollutant at the time a regulatory requirement to control emissions of that pollutant "takes effect" (rather than upon promulgation or the legal effective date of the regulation). PSD program requirements will apply to GHGs from stationary sources on the date that the tailpipe standards for light-duty vehicles (LDV) apply to 2012 model-year vehicles, which EPA determined is January 2, 2011. The issue of whether CO_2 needs to be considered is now moot for post-January 2011 PSD permits. EPA also addressed several outstanding questions regarding the applicability of the PSD and Title V permitting programs to GHGs. Except for this change, EPA reaffirmed the PSD Interpretive Memo and its establishment of the actual control interpretation as EPA's interpretation of the phrase "subject to regulation" found in the PSD provision in CAA §165(a)(4) and EPA regulations that impose technology-based BACT requirements.

At least 17 lawsuits have been filed challenging the light-duty GHG vehicle rule.[243] These cases challenge four EPA rulemakings that followed the Supreme Court's remand in *Massachusetts v. EPA*.[244] These cases have been consolidated in the U.S. Court of Appeals for the District of Columbia (D.C.) Circuit as the *Coalition for Responsible Regulation, Inc. v. U.S. EPA*,[245] but as of July 2011, the case has not been argued. In addition to litigation, GHG regulatory opponents have their supporters in Congress engaged in an ongoing effort to enact legislation to prevent EPA from regulating GHG emissions.[246]

EPA's position is that the onset of the BACT requirement should not be delayed in order for technology or control strategies to be developed. Furthermore, because of the significant administrative challenges presented by the application of the PSD and Title V requirements for GHGs, it is necessary to defer applying the PSD and Title V provisions for sources that are major based only on emissions of GHGs until a date that extends beyond January 2, 2011. EPA will continue to interpret the definition of "regulated NSR pollutant" in 40 C.F.R. §52.21(b)(50) to exclude pollutants that only require monitoring or reporting, but to include each pollutant subject to either a provision in the CAA or CAA-promulgated regulation that requires actual control of emissions of that pollutant. EPA, in its April 2, 2010, interpretation made it clear that provisions in an SIP regulating a pollutant do not make it a nationally regulated pollutant under the CAA that could trigger the need for compliance with other provisions of the CAA.

The CAA's requirements affect carbon sequestration development in the following ways. (1) The CAA's requirements and pending requirements increase the cost and the time required for permitting coal-fired electric power plants, which can make alternative energy projects, energy conservation, natural gas electric power generation, and nuclear power more attractive by reducing the cost advantage of generating electricity using coal.[247] (2) Sequestration may trigger PSD requirements for the entire electric power generation facility (*see* Part III.B.1. below). (3) Sequestration could eventually be considered BACT and be required for new or modified electric power facilities, but EPA at this time is not attempting to define CCS as BACT. Alternatively, IGCC technology, which makes it easier to sequester carbon, may be considered to be BACT. (4) Sequestration facilities, even if freestanding, may require compliance with PSD or NSPS, as well as the operating permit requirements found in CAA Subchapter V.[248]

The electric power industry may be giving up their efforts to permit new coal-fired power plants. On July 9, 2009, Intermountain Power announced that it would allow its permit to build a new plant in Utah to expire.[249] On December 17, 2009, Seminole Electric announced that it was withdrawing its application for a construction permit to build a coal-fired power plant in Florida after three

239. Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 74 Fed. Reg. 55291, 55302 (proposed Oct. 27, 2009). *See also* Alec Zacaroli et al., *EPA Begins Regulation of Greenhouse Gas Emissions Under the Clean Air Act*, 40 Env't Rep. (BNA) 2859 (Dec. 11, 2009).

240. *States Cite Legal Concerns in Urging Delay for EPA GHG Permitting Rule*, XX Clean Air Report (Inside EPA) 25:31 (Dec. 10, 2009).

241. *See* 40 C.F.R. §52.21(b)(23) (2010).

242. U.S. EPA, Reconsideration of Interpretation of Regulations That Determine Pollutants Covered by Clean Air Act Permitting Programs: Final Rule, 75 Fed. Reg. 17003 (Apr. 2, 2010).

243. *EPA GHG Vehicle Rule Faces Slew of Last-Minute State, Industry Lawsuits*, XXI Clean Air Rep. (Inside EPA) 15:34 (July 22, 2010. *See also* Steven D. Cook, *Publication of Greenhouse Gas Tailoring Rule Launches 60-Day Period for Legal Challenges*, 41 Env't Rep. (BNA) 1227 (June 4, 2010); Steven D. Cook, *Chamber of Commerce, Manufacturers Sue EPA Over Greenhouse Gas Regulation*, 41 Env't Rep. (BNA) 1227 (June 4, 2010).

244. Massachusetts v. EPA, 549 U.S. 497, 37 ELR 20075 (2007).

245. D.C. Circuit No. 09-1322, No. 10-1073, No. 10-1092, No. 10-1131, and consolidated cases.

246. *See* Dean Scott, *Republican Want EPA Climate Authority to Move to House Floor Before Summer*, 42 Env't Rep. (BNA) 484 (Mar. 11, 2011).

247. The use of federal environmental laws to increase the costs and delay the construction of coal-fired electric power plants is covered in Reitze, *Carbon Constrained*, *supra* note 27.

248. 42 U.S.C. §§7661-7661f (West 2010).

249. Steve Cook, *With Coal-Fired Plant in Utah Canceled, Sierra Club Says 100 Facilities Shelved*, 40 Env't Rep. (BNA) 1711 (July 17, 2009).

administrative challenges.[250] As mentioned earlier, environmentalists claim plans for 100 new coal-fired plants have been shelved in the United States since 2001.[251] If new coal-burning power plants are not constructed, the pressure to develop CCS technology will be reduced.

1. Sequestration as a PSD/NSR Trigger

EPA has not yet addressed how the CAA requirements apply to plants that install carbon capture equipment. Because of the energy requirements for compressing captured CO_2 prior to transport and sequestration, a power plant will have to burn more fuel to obtain the same net generating capacity. This could increase emissions and potentially trigger the applicability of an NSPS or PSD/NSR requirements. In other words, separating CO_2 from the gas stream could result in new or additional pollution being released, which could trigger NSPS or PSD/NSR applicability.

2. IGCC or Sequestration as BACT

Court decisions have held that BACT/LAER requirements cannot be used to force an applicant to redesign a proposed facility. Thus, BACT/LAER requirements cannot be defined to force a proposed coal-burning plant to use alternative energy, gas, or nuclear power. For example, on August 24, 2006, EPA's EAB ruled that the Agency could not require the use of low-sulfur coal at Peabody Energy's Prairie State proposed facility in Illinois because it would redefine the basic design of the facility, which was planned as a mine-mouth facility that would burn high-sulfur Illinois coal.[252] Subsequently, in *Sierra Club v. EPA*,[253] the U.S. Court of Appeals for the Seventh Circuit ruled that EPA does not have to consider whether the applicant should use low-sulfur coal as a pollution control technology, because such a requirement would require significant modifications of the plant; BACT review cannot be used to require a redesign of a proposed facility.

An important factor for IGCC technology acceptance is whether it is a BACT requirement for a PSD permit by CAA §165(a)(4) or a LAER requirement for an NSR permit in nonattainment areas by CAA §173(a)(2). The difficult question for EPA, or a state permitting authority, is whether IGCC is a pollution control technology that may be required as BACT or a different electric power-generating technology that cannot be imposed by a permitting authority.

It has been argued that IGCC is BACT, even though it is a different production process and is not an "end-of-stack" control. This position is supported by the language of CAA §169(3), which includes different production processes, fuel cleaning, and innovative fuel combustion processes as BACT options. EPA's 1990 draft guidance indicated that it was not the Agency's general policy to redefine an applicant's design for a facility for purposes of considering what is available technology.[254] In the August 6, 2005, Energy Policy Act, Congress stated that it was taking no position on whether IGCC was adequately demonstrated for purposes of CAA §111 or whether it is achievable for the purposes of CAA §§169 or 171.[255] EPA's Stephen D. Page, however, in a letter dated December 23, 2005, stated that IGCC is not BACT, because it involves the basic design of a proposed source.[256] EPA's position was that §165(a)(2) requires alternative sources to be considered at an early stage in the permitting process, but once a technology is selected, §165(a)(4) requires air pollution control requirements to be based on controls that are appropriate for that technology. Moreover, it is not clear that IGCC is a demonstrated technology or that it results in lower emissions than a state-of-the-art pulverized coal plant.

For PSD and NSR permits, CAA §§165(a)(2) and 173(a)(5) provide that a permit may be issued only if an analysis of alternative sites, sizes, production processes, and environmental control techniques for the proposed source demonstrates that the benefits significantly outweigh the environmental and social costs that are imposed by construction or modification. The extent to which alternative analysis can be used to require that an alternative be adopted is not clear, and this ambiguity is likely to be the subject of challenges to permit applications.[257] If an alternative analysis is to be used to stop a project, who will have the power to determine the social values that are to be considered and how these values are to be balanced?

Whether IGCC technology can be required as BACT is still unresolved. The Desert Rock coal-fired power plant is planned to be located on Navajo tribal land in northwest New Mexico. EPA issued a construction permit in 2008. On January 22, 2009, EPA's EAB agreed to hear a challenge to the permit application brought by states and environmentalists. However, on April 27, 2009, EPA asked the EAB to remand *In re Desert Rock Energy Company* to the Agency to review the policy regarding whether IGCC technology is BACT.[258] On September 24, 2009, the

250. Drew Douglas, *Seminole Electric to Withdraw Application for Coal-Fired Electric Generating Unit*, 41 Env't Rep. (BNA) 33 (Jan. 1, 2010).
251. Cook, *Coal-Fired Plant*, *supra* note 249.
252. In re Prairie State Generating Company, PSD Appeal No. 05-05 (EAB Aug. 24, 2006), *available at* http://www.epa.gov/eab.
253. Sierra Club v. EPA, 499 F.3d 653, 37 ELR 20226 (7th Cir. 2007).
254. U.S. EPA, New Source Review Workshop Manual, Draft 1990, 88, *available at* http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf.
255. Energy Policy Act of 2005, Pub. L. No. 109-58, §402 (2005).
256. Steven D. Page, EPA Letter on Use of Integrated Gasification Combined Cycle Technology as BACT, 36 Env't Rep. (BNA) 2666 (Dec. 23, 2005); *see also* Steven D. Cook, *EPA Official Reports Gasification as Standard for New Coal-Fired Electric Power Plants*, 36 Env't Rep. (BNA) 2625 (Dec. 23, 2005).
257. *Compare* In re Hibbing Taconite Co., 2 E.A.D. 838, 1998 EPA App. LEXIS 24, at 11-12; In re Pennsauken County, New Jersey Resource Recovery Facility, 2 E.A.D. 667, 1988 EPA App. LEXIS 27 (Adm'r 1988), *with* In re Hillman Power Co., Ltd. Liab. Corp., PSD Appeal Nos. 02-04 et al., 2002 EPA App. LEXIS 5, at 46-47 (EAB July 31, 1002); In re Kendrall New Century Development, PSD Appeal No. 03-01, 2003 EPA App. LEXIS 3 (EAB Apr. 29, 2003). *See also* Gregory B. Foote, *Considering Alternatives: The Case for Limiting CO_2 Emissions From New Power Plants Through New Source Review*, 34 ELR 10642 (July 2004).
258. *EPA Air Permit May Present First Stationary Source CO_2 Test for Obama*, XXVI Envtl. Pol'y Alert (Inside EPA) 2:27 (Jan. 28, 2009); Tripp Baltz,

request for remand was granted. The Navajo Nation maintains that it is committed to the Desert Rock Project, but is considering a plant redesign, including the possibility of not using coal.[259] On February 18, 2009, the EAB told the Michigan Department of Environmental Quality that it must review a permit for a new power plant at Northern Michigan University to determine whether GHGs should be regulated.[260]

In Texas, a proposed 800-MW pulverized coal power plant was the subject of a challenge by environmentalists because it did not plan to use IGCC technology. On January 29, 2009, a Texas state appeals court ruled in *Blue Skies Alliance et al. v. Texas Environmental Quality Commission* that IGCC is not a viable control technology for a conventional pulverized coal plant, and held that a BACT analysis does not require an alternative to be considered that would require a redesign of the proposed facility.[261]

In Georgia, a state court in *Friends of the Chattahoochee, Inc. v. Couch*[262] decided an appeal from a state administrative law judge awarding a construction permit to a coal-fired power plant. The court remanded the case to the Agency, finding that CO_2 emissions are subject to BACT requirements. The case, now designated *Longleaf Energy Associates LLC v. Friends of the Chattahoochee, Inc.*, was appealed to the Georgia Court of Appeals.[263] On July 7, 2009, the court reversed the lower court, holding CO_2 does not have to be regulated and IGCC technology does not have to be considered as part of a BACT analysis.[264] The case was appealed to the Georgia Supreme Court, but certiorari was denied on September 28, 2009.[265] The plant received its final permits from Georgia's Environmental Protection Division on April 9, 2010.[266]

The Utah Division of Air Quality and the Utah Air Quality Board, in 2004, granted Sevier Power Company an approval order to construct a coal-fired, circulating fluidized bed power plant. The Sierra Club challenged the approval order. The Board challenged the Sierra Club's standing but lost.[267] The Board, after three days of hearings, granted the approval order. The Sierra Club appealed to the Utah Supreme Court.[268] Review was based on the Utah Administrative Procedure Act, under which interpretations of law are reviewed for correctness with little or no deference to the Agency's interpretation. Issues of fact and the Agency's interpretations are reviewed to determine if they are rational and are set aside only if they are arbitrary and capricious or are beyond the tolerable limits of reason.

The first challenge was based on enforcement provisions in both Utah and federal programs that require a review and possible revocation of a permit if construction has not begun within 18 months after the issuance of an approval order. The Court agreed with the Sierra Club that this requirement was not followed and remanded the case to the Division to ensure the most up-to-date control technology was adopted and "the increment limits are not tied up indefinitely."[269] Next, after reviewing the confusing history of whether a BACT analysis is required for CO_2, the Court upheld the Board's decision not to require an analysis until EPA formulates a CO_2 emissions policy. This part of the Court's decision was short-lived because EPA regulated CO_2 on May 7, 2010.[270] The most important part of the decision was the Court's finding that IGCC technology is a control technology that should be evaluated as part of a BACT review. The Court concluded that considering IGCC technology would not require Sevier Power to redefine the design of its proposed facility. Consideration of IGCC "does not compel its adoption; instead it only requires the Power Company to subject IGCC to the five-step top down analysis used to determine the best available technology." The Court set aside the Division's decision and remanded the case. Among the requirements to be met by the Division is that it must conduct a BACT analysis that considers IGCC as an available control strategy.[271]

South Dakota may have issued the nation's first draft air permit for controlling GHGs. The project is an IGCC facility to produce electricity to run a refinery. The state's Department of Energy and Natural Resources (DENR) rejected the use of CCS as BACT for GHGs, because the power needed for CCS would substantially increase criteria pollutants and would increase GHGs by 1.5 tpy. The use of CCS would require 400 MW of electrical and steam production and would double the amount of electricity needed to operate the refinery. The draft permit includes numeric limits on CO_2e per thousand barrels of crude processed, but the purpose of the plant is to refine Canadian tar sands oil, which is an energy-intensive method of obtaining oil and appears to be one step forward and two steps back in

Colorado Officials Ask EPA to Reconsider Permit Decision for New Mexico Power Plant, 40 Env't Rep. (BNA) 674 (Mar. 27, 2009). *See also* Dawn Reeves, *Industry Seeks Novel GHG Deal With EPA After Permit Remanded*, XXVI Envtl. Pol'y Alert (Inside EPA) 20:25 (Oct. 7, 2009). *See also* Steven D. Cook, *EPA Request to Review Desert Rock Permit Violates Clean Air Act, Plant Owner Says*, 40 Env't Rep. (BNA) 1427 (June 19, 2009).

259. Source Watch, *Desert Rock*, http://sourcewatch.org/index.php?title=Desert_Rock (last visited July 4, 2011).

260. In re Northern Michigan University Ripley Heating Plant, EAB, PSD Appeal No. 08-02 (Feb. 18, 2009).

261. Blue Skies Alliance v. Texas Commission on Envtl. Quality, 283 S.W.3d 525 (Tex. App.-Amarillo 2009).

262. Friends of the Chattahoochee v. Couch, 2008 WL 7531591 (Ga. Sup. Ct. June 30, 2008), 38 ELR 20159 (July 4, 2008).

263. *Georgia Appeals Court Will Review Ruling Requiring CO_2 Limit in Permit*, XIX Clean Air Rep. (Inside EPA) 18:11 (Sept. 4, 2008).

264. Longleaf Energy Associates v. Friends of the Chattahoochee, 681 S.E.2d 203 (Ga. Ct. App. 2009), *cert. denied*, S09C1879, 2009 Ga. LEXIS 809 (2009). *See* Barney Tumey, *State Appeals Court Overturns Ruling Vacating Building Permit for Coal-Fired Plant*, 40 Env't Rep. (BNA) 1665 (July 10, 2009). Molly Davis, *Activists Scramble to Block Coal-Fired Utility Without CO_2 Limits*, XX Clean Air Rep. (Inside EPA) 21:40 (Oct. 15, 2009).

265. *See Longleaf*, Source Watch, http://www.sourcewatch.org/index.php?title=Longleaf (last visited July 3, 2011).

266. Barney Tumey, *State Regulators Issue Final Permits for Construction of Coal-Fired Power Plants*, 41 Env't Rep. (BNA) 858 (Apr. 16, 2010).

267. Utah Chapter of the Sierra Club v. Utah Air Quality Bd., 2006 UT 73, ¶ 11, 148 P.3d 975 (2006).

268. Utah Chapter of the Sierra Club v. Utah Air Quality Bd., 2009 UT 76, 226 P.3d 719 (2009).

269. *Id.* at 728.

270. *See* U.S. EPA & U.S. Dep't of Transp., Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule, 75 Fed. Reg. 25523 (May 7, 2010).

271. *Utah Chapter of the Sierra Club*, 226 P.3d at 733.

terms of controlling CO_2e.[272] In Louisiana, the Nucor steel facility was given a PSD GHG permit that rejected CCS without a thorough analysis after EPA's Region VI pressed for the state to consider requiring CCS.[273] That permit is being challenged by the Louisiana Environmental Action Network.[274]

On November 17, 2010, EPA issued "PSD and Title V Permitting Guidance for Greenhouse Gases," and in March 2011, it replaced the guidance with a modified version.[275] The guidance continues to reflect the use of EPA's five-step top-down BACT process but addresses the process for determining BACT for GHGs. Because there is no "add on" technology for controlling GHGs, the guidance stresses the importance of energy-efficiency improvements for new or modified sources in order to burn less fuel.[276] The guidance is ambiguous on what technologies must be considered.

> The permitting authority should take a "hard look" at the applicant's proposed design in order to discern which design elements are inherent for the applicant's purpose and which design elements may be changed to achieve pollutant emission reductions without disrupting the applicant's basic business purpose for the proposed facility. In doing so, the permitting authority should keep in mind that BACT, in most cases, should not be applied to regulate the applicant's purpose or objective for the proposed facility.[277]

The guidance appears to give the permitting authority little useful assistance beyond the existing case law, although it does indicate that the safe course of action is to at least consider a range of options in the first step of the BACT analysis. The guidance indicates that to require the use of natural gas for an applicant seeking to build a coal-fired power plant would, in most cases, be a fundamental redefinition of the project.[278] However, the guidance goes on to express approval for the permitting authority to exercise broad discretion in considering clean fuels or innovative technologies.[279] EPA subsequently discusses whether CCS technology is BACT. The Agency indicates that CCS should be included in Step 1 of the top-down BACT analysis, but it can be eliminated in Step 2, if there is uncertainty that it will work in the situation undergoing review or if it is technically infeasible to use CCS. EPA believes CCS is a promising technology, but indicates that logistical hurdles and the lack of demonstrated availability will probably result in dismissing CCS after a BACT analysis.[280]

3. Sequestration Facilities as a Stationary Source

Sequestration facilities need to be located at sites that will meet government standards. They may be located at a distance from the source of the carbon to be sequestered. They may be under the ownership of an entity that did not generate the carbon to be sequestered. This would make them subject to CAA construction and operating permit requirements, including standards applicable to toxic releases, to the extent that they have emissions sufficient to trigger the various CAA requirements. The primary requirements, however, would be imposed by the SDWA's Class VI permit process that is discussed above in Part III.A.

C. Other Federal Environmental Laws

The Solid Waste Disposal Act as amended by RCRA imposes federal requirements on solid waste and much more stringent requirements on solid wastes that are considered hazardous waste.[281] Solid waste is defined to include discarded material that is solid, liquid, semisolid, or that contained gaseous material.[282] Injection is considered to be "disposal."[283] Sequestered CO_2 would probably meet the definition of solid waste,[284] but because it is not a listed hazardous waste, it would need to exhibit specified characteristics to be regulated as hazardous waste.[285] It would seem unlikely that CO_2 would be considered a hazardous waste, but even if CO_2 is not a hazardous substance, other hazardous contaminants of a power plant's emission stream, if they are listed as hazardous waste, could make the sequestered material a mixture that would be considered hazardous.[286] Thus, sequestered CO_2 may meet the definition of hazardous waste.[287] In March 2010, EPA announced that it was considering proposing a rule under RCRA to exempt CO_2 waste streams from RCRA's hazardous waste law requirements in order to encourage CCS.[288] Such a decision would be important to industry in large part because of the citizen suit provision in RCRA.

The citizen suit provision of RCRA, §7002, allows any person to sue 90 days after notice to the defendant, EPA, and the state where the violation is alleged to be occurring.[289] An action may be brought immediately after

272. *See* Dawn Reeves, *First Draft Refinery GHG Permit Rejects CCS Citing "Energy Penalty,"* XXII Clean Air Rep. (Inside EPA) 6:9 (Mar. 17, 2011). This may not be the first permit with GHG emission limits. A proposed Russell City Energy Co. 600-MW natural gas-fired combined-cycle power plant in California had its GHG emissions subject to BACT requirements when its PSD permit included numeric values for CO_2e emissions based on energy-efficiency determinations. *California Issues First Utility Permit Limiting Greenhouse Gases With BACT*, XXI Clean Air Rep. (Inside EPA) 22:10 (Oct. 28, 2010).
273. Dawn Reeves, *supra* note 272.
274. *Activists Urge EPA to Oppose First GHG Permit for Failing to Meet BACT*, 28 Envtl. Pol'y Alert (Inside EPA) 10:34 (May 18, 2011).
275. *Available at* http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf (last visited July 7, 2011).
276. *Id.* at 21.
277. *Id.* at 26.
278. *Id.* at 27.
279. *Id.* at 28.
280. *Id.* at 36.
281. 40 C.F.R. §261.2 (2010).
282. RCRA §1004(27), 42 U.S.C. §6903(27).
283. *Id.* at §1004(3)
284. *Id.* at §6903(5).
285. 42 U.S.C. §6921(a) (2006); *see also* 40 C.F.R. §261.3 (2010).
286. 40 C.F.R. §261.3(a)(2)(iv) (2010).
287. RCRA §1004(5), 42 U.S.C. §6903(5).
288. *To Speed CCS, EPA Weighs Hazardous Waste Law Exemption for CO_2*, XXVII Envtl. Pol'y Alert (Inside EPA) 6:31 (Mar. 24, 2010).
289. RCRA §7002(b)(1)(A), 42 U.S.C. §6972(b)(1)(A).

notification if the claim involves a violation of the hazardous substances provisions of RCRA.[290] A §7002 action allows a plaintiff to enforce the nondiscretionary actions required by RCRA. Private parties cannot obtain money damages, but they may obtain attorneys fees and expert witness costs.[291]

However, in EPA's final rule on UIC GS, EPA said the types of impurities and their concentrations would likely vary by facility, coal composition, plant operating conditions, and pollutant removal and carbon capture technologies.

> (O)wners or operators will need to determine whether the CO_2 stream is hazardous under EPA's RCRA regulations, and if so, any injection of the CO_2 stream may only occur in a Class I hazardous waste injection well. Conversely, Class VI wells cannot be used for the co-injection of RCRA hazardous wastes (i.e., hazardous wastes that are injected along with the CO_2 stream). EPA supports the use of CO_2 capture technologies that minimize impurities in the CO_2 stream. EPA initiated a rulemaking separate from its final UIC Class VI rule. The RCRA proposed rule plans to examine the issue of RCRA applicability to CO_2 streams being geologically sequestered, including the possible option of a conditional exemption from the RCRA requirements for CO_2 GS in Class VI wells. The SDWA Class VI rule does not change applicable RCRA regulations.[292]

If a solid waste or a hazardous waste may present an imminent and substantial danger to human health or the environment, RCRA §7003 allows the Administrator to issue administrative orders and/or sue in a federal district court to obtain equitable relief or enforce the order. Because EPA has found that CO_2 endangers human health, it may be easier to utilize this section.

CERCLA provides for the cleanup of contamination by hazardous substances that occurred in the past from activities that include industrial waste disposal.[293] The statute defines "hazardous substance" broadly to potentially include sequestered electric power waste streams, and these substances are not covered by the statutes exclusions.[294] CERCLA allows the federal government, state and local governments, and private parties to recover the costs associated with a cleanup operation.[295] Private parties that clean up a release may be able to recover from those responsible for the release, even if the government is not pursuing a CERCLA action.[296] In addition, some states have Superfund statutes that allow for the recovery of damages that are not recoverable under CERCLA.[297]

For CERCLA to apply, a disposed substance must be hazardous. Substances that are hazardous under the major environmental statutes are considered hazardous under CERCLA.[298] CO_2 itself is not listed as a hazardous substance under CERCLA, although EPA's endangerment finding for CO_2 under the CAA could potentially trigger CERCLA liability. More importantly, hazardous contaminants in the CO_2 waste stream could trigger CERCLA liability.

> The CO_2 stream may contain a listed hazardous substance (such as mercury) or may mobilize substances in the subsurface that could react with ground water to produce listed hazardous substances (such as sulfuric acid). Whether such substances may result in CERCLA liability from a GS facility depends on the composition of the specific CO_2 stream and the environmental media in which it is stored (e.g., soil or ground water).[299]

CERCLA §107 exempts federally permitted releases from triggering liability.[300] This should prevent CERCLA liability, but only if the injectate stream remains within the scope of its SDWA Class VI permit.[301] CERCLA also has the potential to affect state tort law.[302]

When a CCS regimen is developed, it will be important to protect those complying with the requirements of the CCS program from RCRA/CERCLA liability if the private sector is to enter this field. This will also require dealing with the issue of liability for CO_2 waste streams contaminated by hydrogen sulfide (H_2S), NO_x, SO_2 and other hazardous substances. Even if CO_2 is not subject to RCRA or CERCLA, it could react with naturally occurring substances found in the injection site that would yield hazardous substances that would expose responsible parties to potential liability.

The Clean Water Act (CWA)[303] would not appear to be applicable to releases of CO_2 to the atmosphere, but the Center for Biological Diversity successfully concluded a settlement with EPA to use CWA §303(d) to develop a total maximum daily load (TMDL) for waters threatened or impaired for ocean acidification due to CO_2 emissions. This could lead to CO_2 being considered a hazardous air pollutant (HAP) under CAA §112, because that section defines an HAP as a pollutant that may adversely impact the environment through ambient concentrations or through deposition.[304]

The National Environmental Policy Act (NEPA)[305] of 1969 is becoming a tool used to force federal agencies to consider global climate change as it relates to actions

290. *Id.* at (b)(2)(A).
291. RCRA §7002(e), 42 U.S.C. §6972(e).
292. UIC Rule, 75 Fed. Reg. at 77260.
293. *See generally* 42 U.S.C. §§9601-9675.
294. CERCLA §101(14), 42 U.S.C. §9601(14).
295. CERCLA §107, 42 U.S.C. §9607.
296. United States v. Atlantic Research Corp., 551 U.S. 128, 37 ELR 20139 (2007).
297. Klass & Wilson, *supra* note 157, at 129.
298. CERCLA §101(14), 42 U.S.C. §9601(14).
299. UIC Rule, 75 Fed. Reg. at 77260.
300. CERCLA §§107, 101(10), 42 U.S.C. §§9607, 9601(10).
301. UIC Rule, 75 Fed. Reg. at 77260.
302. *See generally* Alexandra B. Klass, *From Reservoirs to Remediation: The Impact of CERCLA on Common Law Strict Liability Environmental Claims*, 39 Wake Forest L. Rev. 903 (2004).
303. 33 U.S.C. §§1251-1387, ELR Stat. FWPCA §§101-607.
304. *Regulators Join Industry in Opposing EPA Use of Water Law to Curb CO_2*, XXI Clean Air Rep. (Inside EPA) 12:27 (June 10, 2010).
305. 42 U.S.C. §§4321-4370f, ELR Stat. NEPA §§2-209.

within the Agency's jurisdiction. If a federal agency does not comply with NEPA, a legal challenge can be used to slow the progress of proposed projects. Because NEPA is primarily limited to achieving procedural compliance, eventually, a federal agency will produce a document that meets the statute's requirements. But delay can be costly and result in a project being abandoned by an applicant.

Over the past decade, courts have decided several cases involving whether consideration of climate change implications is a necessary part of NEPA analysis. In *Border Power Plant Working Group v. DOE*,[306] the U.S. District Court for the Southern District of California held that NEPA requires an analysis of the global warming implications of federal actions concerning the construction of power lines to carry electricity from new power plants in Mexico to southern California. In *Mid States Coalition for Progress v. Surface Transportation Board*,[307] the U.S. Court of Appeals for the Eighth Circuit held that the Board had violated NEPA by failing to analyze the global warming impacts of a new rail line to transport coal prior to approving the project. The Board then prepared a minimal supplemental environmental impact statement (SEIS) that resulted in new litigation, in which the Eighth Circuit found the SEIS to be adequate.[308]

In *Center for Biological Diversity v. National Highway Traffic Safety Administration*, the U.S. Court of Appeals for the Ninth Circuit on August 18, 2008, remanded a rule entitled "Average Fuel Economy Standards for Light Trucks, Model Years 2008-2011."[309] The petitioner's challenge to the rule was based on the arbitrary, capricious, and abuse-of-discretion standard under the Administrative Procedure Act (APA),[310] in which violations of NEPA and the Energy Policy and Conservation Act of 1975 were alleged.[311] The court remanded the case because of deficiencies in the National Highway Traffic Safety Administration's compliance with both statutes. The court reviewed the requirements imposed by NEPA and found numerous failures to comply with the statute, including a failure to adequately assess the cumulative impacts of GHG emissions on climate change and the environment.[312]

On February 18, 2010, the Council on Environmental Quality (CEQ) released two draft guidance documents concerning the application of the NEPA process to climate change and GHG emissions.[313] The first document is "Draft NEPA Guidance on Consideration of the Effects of Climate Change and Greenhouse Gas Emissions,"[314] and the second document is "Draft Guidance for NEPA Mitigation and Monitoring."[315] Neither document is to become effective until issued in final form.

The first document affirms the applicability of NEPA and the related applicable regulations at 40 C.F.R. §§1500-1508 to GHG emissions and climate change and the need for federal agencies to reduce their adverse impacts through GHG emission-reduction efforts and adaptation measures. The guidance requires agencies to consider the climate-changing effects of GHG emissions that would result from the proposed action or alternative actions. Carbon capture and sequestration are among the alternatives that may be considered. The guidance makes a direct annual release of 25,000 metric tpy of CO_2e GHG emissions, or more, a base indicator of the need for a quantitative and qualitative assessment. However, long-term releases of less than 25,000 tons of direct or indirect emissions require NEPA-based analysis if the impacts are meaningful. This guidance is not applicable to federal land and resource management, but the CEQ "seeks public comment on the appropriate means of assessing the GHG emissions and sequestration that are affected by federal land and resource management decisions."[316] EPA's Tailoring Rule uses a 75,000-tpy of CO_2e threshold for new stationary sources seeking PSD permits, so it is possible that projects that do not require a construction permit will need to comply with NEPA.

The NEPA analysis serves two principal goals. It can reduce vulnerability to climate change impacts by mitigating adverse effects and providing guidance for adaptation response. It can also aid in achieving reductions in GHG emissions through energy conservation measures, reductions in energy use, and by promoting the use of renewable energy technologies. The guidance document encourages the quantification of cumulative emissions over the life of a project and implementation of measures to reduce GHG emissions, including the consideration of reasonable alternatives. An agency may use a programmatic analysis for agency activities that can be incorporated by reference into subsequent NEPA-based analysis for individual projects. The guidance refers to the use of techniques specified in the CAA's Mandatory Reporting of Greenhouse Gases Rule for the quantification of GHG emissions.[317] The guidance concludes that it is not creating a new component of NEPA analysis, but that climate change is a

306. Border Power Plant Working Grp. v. Dep't of Energy, 260 F. Supp. 2d 997 (S.D. Ca. 2003).
307. Mid States Coal. for Progress v. Surface Transp. Bd., 345 F.3d 520 (8th Cir. 2003).
308. Mayo Found. v. Surface Transp. Bd., 472 F.3d 545, 556, 37 ELR 20006 (8th Cir. 2006).
309. Ctr. for Biological Diversity v. Nat'l Highway Traffic Safety Admin., 538 F.3d 1172, 1182, 38 ELR 20214 (9th 2008) (remanding the rule found at 71 Fed. Reg. 17566 (Apr. 6, 2006)).
310. *See generally* 5 U.S.C. §§701-706.
311. *See generally* 49 U.S.C. §§32901-32919.
312. *Ctr. for Biological Diversity*, 538 F.3d at 1216.
313. *National Environmental Policy Act (NEPA) Draft Guidance, Consideration of the Effects of Climate Change and Greenhouse Gas Emissions*, 75 Fed. Reg. 8046 (Feb. 23, 2010).
314. Nancy H. Sutley, Council on Envtl. Quality, Memorandum for Heads of Federal Departments and Agencies: Draft NEPA Guidance on Consideration of the Effects of Climate Change and Greenhouse Gas Emissions (2010), *available at* http://ceq.hss.doe.gov/nepa/regs/Consideration_of_Effects_of_GHG_Draft_NEPA_Guidance_FINAL_02182010.pdf.
315. Nancy H. Sutley, Council on Envtl. Quality, Memorandum for Heads of Federal Departments and Agencies: Draft Guidance for NEPA Mitigation and Monitoring (2010), *available at* http://ceq.hss.doe.gov/nepa/regs/Mitigation_and_Monitoring_Draft_NEPA_Guidance_FINAL_02182010.pdf.
316. *Id.* at 2.
317. U.S. EPA, Mandatory Reporting of Greenhouse Gases, 74 Fed. Reg. 56259 (2009) (to be codified at 40 C.F.R. pts. 86, 87, 89).

potentially important factor to be considered within the existing NEPA framework.

The second document provides guidance concerning how mitigation and monitoring of GHGs should be treated in the NEPA process and is effective January 21, 2011. The document's Appendix includes an overview of the U.S. Department of the Army Regulation, which the CEQ considers to be a model that should be adopted by other agencies.[318] Mitigation can be in the form of alternatives with reduced adverse environmental impact that form an integral element in the design of a project. Mitigation is to be used "to avoid, minimize, rectify, reduce, or compensate the adverse environmental impacts associated with [agency] actions."[319]

Mitigation goals should be clear and subject to measurable performance standards, with monitoring used to ensure mitigation measures are implemented and are effective. Mitigation can be in the form of selecting alternatives having reduced adverse environmental impacts that are an integral element in the design of a project. If mitigation is used to avoid the need for an EIS, it should be binding, enforceable, and included in the finding of no significant impact (FONSI). If mitigation measures required to reduce environmental impacts below significance levels are found to be ineffective, an EIS should be prepared.

The draft CEQ guidance on GHGs provides an exemption for federal land management activities that would exempt federal oil and gas leasing from NEPA-based review. This led to a lawsuit in which a federal district court in New Mexico agreed to hear a challenge to the Bureau of Land Management's (BLM's) granting of oil and gas leases without considering emissions of the GHG methane.[320]

D. Laws Administered by the U.S. Department of the Interior

BLM, within the U.S. Department of the Interior (DOI), has jurisdiction over CO_2 injected on federal lands. BLM does not regulate pipelines, but it is the agency that grants rights-of-way to place pipelines on federal lands. It is not clear whether BLM has authority to establish a funding mechanism for management of sequestration on its lands.[321] Moreover, it has not yet been resolved which federal agency will have oversight over long-term liability for sequestration or other aspects of the program.[322] The Climate Change Technology Program (CCTP) that was authorized by the Energy Policy Act of 2005 is charged with interagency coordination and can be expected to play a role in CCS development.[323]

The Energy Independence and Security Act of 2007 expanded DOI's responsibility for carbon sequestration.[324] Section 711 directs the DOI to develop a methodology for assessing the potential for geologic storage of CO_2 and to use the methodology to assess the nation's capacity for storage. Section 712 requires DOI to assess the capacity of ecosystems to sequester carbon. Section 713 requires the DOI to maintain records, and an inventory, of the quantity of CO_2 stored within federal mineral leaseholds. Section 714 directs the DOI to report on its recommended regulatory framework for managing geologic carbon sequestration on public lands. The DOI is to assess the options for obtaining fair market value for using public lands, procedures for public participation in the process, and recommend procedures for protecting natural and cultural resources.[325] It must also assess the status of liability related to geologic sequestration on public land, including situations where the government owns the mineral rights but not the overlying surface estate.[326] The DOI is to identify issues relating to pipeline rights-of-way. It is to recommend additional legislation that may be needed to carry out its responsibilities for land management, leasing, and pipeline rights-of-way.[327]

On June 3, 2009, the report entitled "Framework for Geological Carbon Sequestration on Public Land" was released.[328] The report recommends criteria for identifying potential sites for geological carbon sequestration and proposes a regulatory regime for leasing public lands for sequestration. The report identifies four challenges that need to be addressed in developing a regulatory regimen. First, it must be determined whether CO_2 is "a commodity, resource, contaminant, waste, or pollutant," and pure CO_2 must be distinguished from the mixtures containing H_2S, CO, methane, oxides of nitrogen and sulfur, and other contaminants that can be expected to be found in sequestered streams of CO_2.[329] Second, potential conflicts with other lands uses, including mining, oil and gas production, coal production, geothermal development, and groundwater use, as well as potential impacts on surface land uses, such as recreation, grazing, cultural resources, and community development, need to be addressed.[330] Third, the issue of long-term liability, including its scope and the terms of stewardship, needs to be addressed, including the potential conflict of sequestration with BLM's mandate to manage public lands for multiple uses.[331] Fourth, geological car-

318. The Army's regulations are found at 32 C.F.R. §651 (2010).
319. Sutley, *supra* note 315, at 7. *See* Envtl. Analysis of Army Actions, 32 C.F.R. §651.1 (2010).
320. Amigos Bravos v. Bureau of Land Mgmt., No. Cir. 09-0037, slip op. (D.N.M. Feb. 9, 2010); *see also* Molly Davis, *Court to Weigh GHG Review for Federal Lands Exempt Under NEPA Guide*, 27 Envtl. Pol'y Alert (Inside EPA) No. 5, 26 (Mar. 10, 2010).
321. GAO, *supra* note 45, at 30.
322. Erica Martinson, *Energy Law Gives EPA Shared Powers Over CO_2 Storage Program*, XIX Clean Air Rep. (Inside EPA) 2:8 (Jan. 24, 2008).
323. Energy Policy Act of 2005, Pub. L. No. 109-58 (Aug. 8, 2005).
324. Energy Independence and Security Act of 2007, Pub. L. No. 110-140, 121 Stat. 1492 (2007).
325. Cong. Res. Serv., *Energy Independence and Security Act of 2007: A Summary of Major Provisions* 15 (Dec. 21, 2007).
326. *Id.*
327. *Id.*
328. U.S. DOI, *Framework for Geological Carbon Sequestration on Public Land* (June 3, 2009).
329. *Id.* at 1.
330. *Id.*
331. *Id.*

bon sequestration on public lands involving split estates or lands where the surface is managed by agencies other than BLM need to be addressed.[332]

Currently, there is no specific authority for leasing lands administered by BLM for CCS. However, the Federal Land Policy and Management Act (FLPMA) authorizes the Secretary of the Interior to issue leases, permits, and easements for the use, occupancy, and development of the public lands.[333] Carbon sequestration on public lands will require amending the applicable BLM Resource Management Plan (RMP).[334] Because CCS leases could prevent future uses of the land for other purposes or withdrawal of the land for military or other federal uses, it is expected that Reasonable Foreseeable Development Scenarios (RFDS) similar to the process used for oil and gas leasing will be required prior to leasing.[335] Leasing provisions of the Mineral Leasing Act (MLA) will be applicable.[336] It is unclear what federal liability under the MLA will be for carbon sequestration on lands administered by BLM or what BLM's options will be if its property interests are adversely affected. If the mineral estate has been split, then determining the obligations and benefits of interests in land will be further complicated.[337]

The Endangered Species Act (ESA)[338] is another statute that could be a barrier to geological carbon sequestration. The law was enacted in 1973 and has been amended a number of times, most recently in 1988.[339] The purpose of the Act includes the conservation of ecosystems upon which endangered and threatened species depend. The statute requires all federal departments and agencies to use their authority to conserve endangered and threatened species, and to cooperate with state and local agencies to resolve water issues to conserve these species.[340] The Secretaries of Commerce and the Interior share the responsibility for achieving the Act's goals.[341] The DOI delegated implementation of the Act to the U.S. Fish and Wildlife Service (FWS).[342] The U.S. Department of Commerce delegated responsibility to the National Marine Fisheries Service (NMFS) within the National Oceanic and Atmospheric Administration (NOAA).[343]

The FWS and the NMFS determine which species are endangered or threatened based on ESA §4 criteria.[344] After a species is listed, regulations must be promulgated to conserve the species,[345] and a recovery plan must be developed and implemented to protect the species.[346] Designating critical habitat is mandatory, unless it is not prudent or not determinable.[347] ESA §11 contains numerous prohibitions to prevent harm to listed species,[348] as well as a permit program that allows incidental taking of a listed species.[349] Violations of the Act can result in the imposition of civil or criminal penalties.[350]

There are more than 100 species in the western United States that qualify for protection under the ESA or under state programs for sensitive species. Species of concern include fish, amphibians, reptiles, birds, mammals, and mollusks.[351] BLM has rescinded drilling permits for coal-bed methane projects in Wyoming because of concern for elk habitat.[352] The Prairie Dog Recovery and Implementation Plan is a limitation on economic development in southern Utah.[353] Restrictions imposed by BLM to protect the sage grouse concern the oil and gas industry and the wind energy industry.[354] On March 5, 2010, the FWS added the sage grouse to the list of candidate species for protection under the ESA.[355] Oil, gas, and coal-bed methane development, as well as wind energy development, are negatively affecting sage grouse populations, resulting in an agreement by the U.S. Department of Agriculture and the DOI, signed on April 13, 2010, to promote and preserve the habitat of the greater sage grouse and sage-brush ecosystems in 11 western states.[356] The development of CCS facilities can be expected to impact land that is habitat for endangered species, and will likely trigger ESA-based lawsuits.

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332. *Id.* at 2. BLM is responsible for 700 million acres of lands with federal mineral estates. *Id.* at 10.
333. 43 U.S.C. §1732(b).
334. *Framework for Geologic Carbon Sequestration*, *supra* note 328, at 10.
335. *Id.* at 7.
336. 30 U.S.C. §226.
337. *Framework for Geologic Carbon Sequestration*, *supra* note 328, at 12.
338. 16 U.S.C. §§1531-1544, ELR Stat. ESA §§2-18. The Act repealed the Endangered Species Conservation Act of 1969, Pub. L. No. 91-135 (1969), which modified the Endangered Species Preservation Act of 1966, Pub. L. No. 89-669 (1966).
339. The Act is codified at 16 U.S.C. §§1531-1544.
340. 16 U.S.C. §1531(b) & (c).
341. 50 C.F.R. pt. 402.01-.48.
342. *See* 50 C.F.R. pts. 17, 451-53.
343. *See id.* pts. 222-24.
344. 16 U.S.C. §1533.
345. *Id.* §1533(d).
346. *Id.* §1533(f).
347. Center for Biological Diversity v. U.S. Fish & Wildlife Service, 450 F.3d 930, 935, 36 ELR 20102 (9th Cir. 2006). Nondeterminable is defined at 50 C.F.R. §424.12(a)(2).
348. 16 U.S.C. §1538.
349. *Id.* §1539.
350. *Id.* §1540.
351. *See, e.g.*, State of Utah, *Utah Sensitive Species List*, http://dwrcdc.nr.utah.gov/ucdc/ (last visited July 3, 2011). *See also* J.B. Ruhl, *Adapting the Endangered Species Act to Climate Change*, 41 Trends (ABA) 2:8 (Nov./Dec. 2009).
352. Tripp Baltz, *Wyoming BLM Office Halts Oil, Gas Drilling After Concerns Raised About Elk Habitat*, 40 Env't Rep. (BNA) 2902 (Dec. 18, 2009).
353. Mark Havnes, *Plan Could Make Peace Between Humans, Beasts*, Salt Lake Trib., Feb. 15, 2010, at B5.
354. *See* Tripp Baltz, *BLM Office in Wyoming Issues Policy for Sage Grouse, Resource Planning*, 41 Env't Rep. (BNA) 82 (Jan. 8, 2010); Tripp Baltz, *Departments of Agriculture, Interior Reach Agreement on Sage Grouse Habitat*, 41 Env't Rep. (BNA) 851 (Apr. 16, 2010); Martha Kessler, *Opponents of Nantucket Sound Wind Farm File Lawsuit in Federal Court to Halt Project*, 41 Env't Rep. (BNA) 1462 (July 2, 2010). (The wind energy off the coast of Massachusetts is being challenged based on the ESA and the Migratory Bird Treaty).
355. Fact Sheet, U.S. Fish and Wildlife Service, *Endangered Species Act Listing Decision for the Greater Sage Grouse* 1 (Mar. 5, 2010), *available at* http://www.fws.gov/mountain-prairie/species/birds/sagegrouse/FactSheet03052010.pdf. (Nevertheless, the FWS is being sued for not acting aggressively enough to protect the sage grouse. Tripp Baltz, *Activists Sue Fish and Wildlife for Delaying Protection of Sage Grouse in Western States*, 41 Env't Rep. (BNA) 1540 (July 9, 2010).
356. Press Release, U.S. FWS, Federal Agencies Sign Agreement to Protect Sage Grouse Habitat (Apr. 13, 2010), *available at* http://www.fws.gov/news/NewsReleases/showNews.cfm?newsId=F83C2D7B- C73B-3080-4E35D13CDC9DBAF9.

A CCS program will require the construction of a pipeline system, which may be subject to environmental opposition. For example, the Ruby gas pipeline that will run from Wyoming to Oregon is a project of a subsidiary of El Paso Corporation. It has been the target of litigation brought by the Center for Biological Diversity based on a claim that it will harm species such as the Lahontan cutthroat trout, Warner Creek sucker, Lost River sucker, and the Colorado pikeminnow. Two other environmental groups ended their opposition after El Paso agreed to spend $20 million to protect sagebrush habitat, but an association of ranchers is seeking $15 million for rangeland improvements, and the Sierra Club is seeking to force the use of a longer alternative route with less adverse environmental impact.[357]

E. DOE

DOE, primarily through the NETL, has been active in promoting the development of a framework and infrastructure needed to validate and deploy carbon sequestration technologies. DOE established its carbon sequestration program in 1997. It created seven Regional Carbon Sequestration Partnerships (RCSPs), with more than 350 organizations in 43 states, three Native American organizations, and four Canadian provinces as participants.[358] The seven regional partnerships encompass 97% of the nation's coal-fired CO_2 emissions, 97% of the industrial CO_2 emissions, 96% of U.S. land, and nearly all of the potential sequestration storage sites.[359]

The program was to develop partnerships, identify potential carbon sources and projects, evaluate infrastructure needs, establish monitoring, mitigation, and verification protocols, and implement sequestration projects. DOE's RCSPs' initiative is being implemented in three phases: the characterization phase (2003-2005); the validation phase involving small-scale field tests (2005-2010); and the development phase that involves large-scale carbon storage projects (2008-2017).[360] Data from the partnerships characterizing sources and sinks are integrated into the National Carbon Sequestration Database and Geographic Information System (NATCARB).[361] The RCSPs assessed the storage capacity for CO_2 and published their findings in November 2008.[362]

Other DOE programs related to sequestration include: the IGCC and FutureGen programs previously discussed, the Innovations for Existing Plants program, and the Clean Coal Power Initiative, which supports R&D of advanced coal-based technologies that capture and sequester CO_2 emissions.[363] DOE also is charged with monitoring, verification, and accounting for the sequestration program in order to demonstrate that projects meet DOE's goal of 95% to 99% retention. A challenge for this effort is to develop the technology and procedures to assure that leakage of 5% or less can be detected.[364]

In Phase III of the RCSP program, nine large-scale projects represent a major expansion of the 22 small-scale projects that were part of the validation phase. The Southwest Regional Partnership includes Arizona, Colorado, Kansas, New Mexico, Oklahoma, Texas, Utah, and Wyoming. The partnership plans to work with Resolute Natural Resources Company and the Navajo Nation Oil Company to inject CO_2 for 3.5 years leading up to 150,000 tpy.[365] This is equivalent to the CO_2 produced by a 1,000-MW plant in about nine minutes of operation.[366] The injection site is the Greater Aneth Field, which is the largest oil field in the Paradox Basin located in southeast Utah near Bluff, Utah. The CO_2 will come from the McElmo Dome and is 98% pure. It arrives at a pressure of about 2,750 pounds per square inch (psi), which allows injection without additional compression.[367]

The Southeast RCSP will inject CO_2 into Tuscaloosa Massive Sandstone at two locations. The first stage involves injecting 1.5 million tons of CO_2 per year into the saline reservoir associated with an oil field. The second stage will be to inject post-combustion CO_2 from an existing power plant into a sequestration site near the plant.[368] The Plains CO_2 RCSP is working with the owner of one of the largest gas processing plants in North America to inject 1.1 million tons per year of a mixture of CO_2 and H_2S into a limestone and dolomite formation at a depth of approximately 7,200 feet near Fort Nelson in northeastern British Columbia.[369]

The Midwest Geologic Sequestration Consortium is partnering with the Archer Daniels Midland Company

357. Mead Gruver, *Group Sues to Block Ruby Pipeline*, Salt Lake Trib., Aug. 1, 2010, at B5; *Ranchers Reach Tentative $15M Deal Over Ruby Pipeline*, Salt Lake Trib., Aug. 9, 2010, at B6.
358. *Carbon Sequestration: Regional Carbon Sequestration Partnerships*, U.S. DOE, NETL, http://www.netl.doe.gov/technologies/carbon_seq/partnerships/partnerships.html (last visited July 3, 2011).
359. *Carbon Sequestration Regional Partnerships*, U.S. DOE, Fossil Energy Office of Comms., http://fossil.energy.gov/programs/sequestration/partnerships/ (last visited July 3, 2011). The RCSPs are Big Sky RCSP; Plains CO_2 RCSP; Midwest Geological Sequestration Consortium; Midwest Regional Sequestration Partnership; Southeast RCSP; Southwest Regional Partnership on Carbon Sequestration; and the West Coast RCSP.
360. *See generally Technologies: Carbon Sequestration*, U.S. DOE, NETL, http://www.netl.doe.gov/technologies/carbon_seq/partnerships/partnerships.html (last visited July 3, 2011).
361. NATCARB, http://www.natcarb.org/ (last visited July 3, 2011).
362. U.S. DOE, NETL, 2008 Carbon Sequestration Atlas of the United States and Canada, *available at* http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasII/atlasII.pdf.
363. GAO, *supra* note 45, at 14.
364. *Carbon Sequestration: Monitoring Verification, and Accounting (MVA)*, U.S. DOE, NETL, http://www.netl.doe.gov/technologies/carbon_seq/core_rd/mva.html (last visited July 2, 2011).
365. *Carbon Sequestration: Regional Carbon Sequestration Partnerships*, U.S. DOE, NETL, http://www.netl.doe.gov/technologies/carbon_seq/partnerships/partnerships.html (last visited July 2, 2011), http://www.netl.doe.gov/technologies/carbon_seq/core_rd/mva.html (last visited July 3, 2011).
366. This assumes about one ton of CO_2 is emitted for each MW hour.
367. Energy & Geoscience Institute, The University of Utah, http://co2.egi.utah.edu/projectsites/paradox/index.htm (last visited July 3, 2011).
368. U.S. DOE, *Carbon Sequestration Regional Partnerships*, http://www.fossil.energy.gov/sequestration/partnerships/index.html (last visited July 26, 2011); NETL, *Southeast Regional Carbon Sequestration Partnership—Development Phase*, *available at* http://www.netl.doe.gov/publications/factsheets/project/Project680_4P.pdf.
369. NETL, *Plains CO_2 Reduction Partnership—Development Phase—Large Scale Field Tests*, *available at* http://www.netl.doe.gov/publictions/factsheets/project/Project679_4P.pdf.

(ADM) to inject one million metric tons of CO_2 over three years at a depth of 7,230 feet in the Mount Simon Sandstone Formation in Decatur, Illinois. The project will sequester nearly pure CO_2 from ADM's ethanol production.[370] Many other projects are in the planning stage, but there is no commercial-scale demonstrated technology for use at electric generating plants to capture and store CO_2.[371] The NETL is working to develop a portfolio of safe, cost-effective, commercial-scale GHG sequestration technologies. Its primary objectives are to reduce the cost and energy penalty of CO_2 capture and to improve storage permanence and safety of geological storage.[372]

These are just a few examples of an extensive program to demonstrate CCS is applicable to commercial-scale electric generating plants, because at this time, there is no demonstrated technology to capture and store CO_2 at such plants.[373] The NETL is funding projects to develop a portfolio of safe, cost-effective, commercial-scale GHG sequestration technologies. Its primary objectives are to reduce the cost and energy penalty of CO_2 capture and to improve storage permanence and safety of geological storage.[374] DOE has the major federal responsibility for developing carbon sequestration programs, but other government agencies are increasingly getting involved.

Two EPA regional offices are participants in several of the regional partnerships and state regulatory agencies, and companies in the private sector are among the participants. As the RCSP program matures, participation by other government agencies is expected to grow. DOE also is providing $126.6 million to conduct large-scale CCS tests in Ohio and California.[375] The Canadian government is planning to spend U.S. $114 million for eight CCS projects in western Canada.[376] On March 25, 2009, EPA approved a permit for a small carbon sequestration project in Arizona conducted by the West Coast Regional Carbon Sequestration Partnership (WESTCARB). EPA and Arizona's Department of Environmental Quality approved permits for a pilot sequestration project at the Arizona Public Service Company's Cholla Power Plant in Joseph City, Arizona. This project is to study sequestration, but it is not intended to sequester CO_2.[377] Virginia Dominion Power is seeking federal money to capture CO_2 from its Virginia City Hybrid Energy Center that is now under construction, but environmental groups are litigating to prevent the plant from being completed.[378]

The Energy Independence and Security Act of 2007 requires DOE, the DOI, and EPA to establish programs to encourage CCS projects.[379] On October 3, 2008, the Emergency Economic Stabilization Act became law.[380] Section 115 provides a $20 tax credit for each ton of CO_2 that is sequestered. On May 15, 2009, DOE announced that it would spend $2.4 billion to expand and accelerate commercial deployment of CCS technology, with the money coming from the 2009 American Recovery and Reinvestment Act (ARRA).[381] On June 10, 2010, DOE announced grants of as much as $612 million to support CCS projects at a new methanol plant, an oil refinery, and an ethanol plant.[382] On July 7, 2010, DOE announced grants totaling $51.7 million for CCS projects at electric power plants.[383]

F. *Laws Administered by the DOT*

Safety regulations for CO_2 pipelines will be within the jurisdiction of the DOT's Pipeline and Hazardous Materials Safety Administration (PHMSA) for pipelines that affect interstate commerce. The Hazardous Liquid Pipeline Act of 1979, as amended, regulates interstate pipelines and provides minimum standards for states that regulate intrastate pipelines.[384] The PHMSA regulates the design, construction, operation and maintenance, and spill-response planning for pipelines.[385] The PHMSA applies nearly the same safety regulations to CO_2 pipelines as it applies to pipelines carrying hazardous liquids.[386] The PHMSA will need to reevaluate its legal requirements for pipelines if a large-scale sequestration program is to develop. It will need to deal with cross-jurisdictional issues involving multiple federal agencies, as well as state regulatory agencies.

The federal authority to regulate pipelines that are used exclusively for CO_2 transport is exercised by the U.S. Surface Transportation Board.[387] The Board has authority to regulate the rates charged by pipeline companies, but it may only respond to complaints by third parties, and its authority is limited compared to the authority of the Federal Energy Regulatory Commission (FERC) to regulate

370. NETL, *Midwest Geological Sequestration Consortium—Development Phase—Large Scale Field Test*, *available at* http://www.netl.doe.gov/publications/factsheets/project/Project678_4P.pdf.
371. Lynn Garner, *Coal, Electricity Industries Ask White House to Double Funding for Carbon Technologies*, 39 Env't Rep. (BNA) 157 (Jan. 25, 2008).
372. *See Technologies: Carbon Sequestration*, *supra* note 360.
373. Lynn Garner, *supra* note 371.
374. *See* http:www.netl.doe.gov/technologies/carbon_seq/index.html (last visited July 3, 2011).
375. Leora Falk, *Energy Department to Provide Funds for West Coast, Midwestern Projects*, 39 Env't Rep. (BNA) 898 (May 9, 2008).
376. Peter Menyasz, *Canadian Agency Commits $114 Million for Eight Carbon Capture, Storage Projects*, 40 Env't Rep. (BNA) 761 (Apr. 3, 2009).
377. *EPA Plan to Seek Comment on Sequestration Data May Delay CCS Rule*, XXVI Envtl. Pol'y Alert (Inside EPA) 7:35 (Apr. 8, 2009).
378. Jeff Day, *Virginia Tech, Dominion Seek Stimulus Funds for Carbon Capture Demonstration Project*, 40 Env't Rep. (BNA) 2056 (Aug. 28, 2009).
379. 42 U.S.C. §16293.
380. Emergency Economic Stabilization Act of 2008, Pub. L. No. 110-343, 122 Stat. 3765 (2008).
381. Steven D. Cook, *Carbon Capture, Storage to Get $2.4 Billion in Recovery Funds, Secretary Chu Announces*, 40 Env't Rep. (BNA) 1164 (May 22, 2009).
382. Steven D. Cook, *More Than $600 Million in Stimulus Grants Support Industrial Carbon Capture, Storage*, 41 Env't Rep. (BNA) 1356 (June 18, 2010).
383. Steven D. Cook, *DOE Announces $51.7 Million to Fund Post-Combustion Carbon Capture Projects*, 41 Env't Rep. (BNA) 1515 (July 9, 2010). The projects include $14,756,199 to capture CO_2 at Arizona Public Services' Cholla Power Plant. *Id.*
384. 49 U.S.C. §601 (2006).
385. 49 C.F.R. §§190, 195-199 (2010).
386. Parformak & Folger, *supra* note 62, at CRS-16.
387. The Surface Transportation Board was created by the Interstate Commerce Commission Termination Act of 1995. Pub. L. No. 104-88, 109 Stat. 803. Its jurisdiction extends to pipelines transporting commodities other than water, oil, or natural gas. 49 U.S.C. §15301(2006).

natural gas and oil pipelines.[388] The Board has no authority to regulate pipeline construction, nor does it have eminent domain authority. It cannot require companies seeking to build pipelines to obtain certificates of public convenience and necessity, such as FERC requires for the construction of interstate natural gas pipelines.[389] If pipelines are to be placed on federal land managed by BLM, the provisions of FLPMA or the MLA will apply.[390] The MLA imposes common carrier requirements, but FLPMA does not. It is not clear what rules would apply to pipelines carrying CO_2 for sequestration.[391]

Site approval is based primarily on state law, which is intertwined with local concerns and may involve a complex and protracted process.[392] If pipelines are to be constructed, "not in my backyard" (NIMBY) opposition should be expected. This issue was addressed in Montana, when H.B. 338 became law on April 16, 2009. It grants owners of pipelines transporting CO_2 common carrier status, which allows them to use eminent domain to acquire private property.[393]

It would appear that more comprehensive federal legislation is needed to establish which agency will regulate pipelines used for CO_2 transport.[394] Such legislation will need to address the planning and siting of CO_2 pipelines, as well as providing for the promulgation of regulations concerning rates and terms of service for interstate CO_2 pipelines.

IV. Conclusion

For the foreseeable future, costs will be the primary barriers to the implementation of CCS. This includes the high retrofit costs for existing pulverized coal-fired plants, the high costs of separating CO_2 from the other gases and liquefying it, the costs of the needed transportation infrastructure, the costs of creating a storage facility and monitoring long-term storage, and the costs of alternative generating technologies, such as IGCC. The absence of any commercial-scale use of CCS at a large power plant is an important constraint on program development, because meaningful cost data is difficult to obtain. DOE has focused on IGCC as a promising technology for use with CCS, but it is more costly than conventional technology.

At this time, carbon sequestration has not been demonstrated to be a commercially viable technology. No sequestration application has been successfully deployed at the scale necessary for demonstrating that it is a practical and reasonable way to deal with releases of carbon to the atmosphere. The fact that sequestration has been used for enhanced oil and gas production does not demonstrate that long-term sequestration of commercial quantities of CO_2 will be a viable option. For this reason, if sequestration on a commercial scale is to occur, DOE will need to play a major role in funding and evaluating this technology at a commercial scale, and the federal government will need to provide a legal environment that nurtures a new industry.

CO_2 capture and storage could become a necessity if coal is to be used for electric power generation in a carbon-constrained economy, but the high costs of CCS could make natural gas-fired plants, as well as nuclear power and renewable power, more attractive to utilities than trying to deal with sequestration. Coal accounted for 48% of the U.S. electric power generated in 2008, but the majority of the coal-fired plants are more than 30 years old.[395] Natural gas-fired power plants generated 21% of the electricity, but most plants were built in the past 10 years, and it is the technology currently favored by the electric power sector.[396] Natural gas has lower carbon and conventional emissions than coal, but it has enhanced attractiveness because prices dropped from a high of $10.82 per thousand cubic feet (mcf) in mid-2008[397] to $4.21 per mcf on December 1, 2010, as domestic natural gas production increased.[398] Many coal-burning power plants are being retired or repowered to use natural gas.[399] Renewable portfolio requirements are helping to spur wind and solar generation.[400] Energy-efficiency improvements can reduce demand at less than one-half the cost of constructing new generating facilities.[401] While regulatory demands to reduce carbon emissions could make CCS more attractive, the continuously more stringent pollution control requirements and the associated costs make coal-fired power plants a questionable investment. Sequestration is a way of dealing with emissions from an electric generation technology that needs to be improved if it is to be commercially adopted. This creates ongoing pressure on sequestration supporters to lower the costs of geological carbon sequestration in order to use the nation's lowest cost and most plentiful source of energy: coal.

388. Parformak & Folger, *supra* note 62, at CRS-7.
389. *Id.* at CRS-8. *See also* Natural Gas Act, 15 U.S.C. §§717 et seq. (2006).
390. *See* 43 U.S.C. §35 (2006); 30 U.S.C. §185 (2006).
391. Parforman & Folger, *supra* note 62, at CRS-9.
392. *Id.*
393. Perri Knize, *Montana Governor Signs Measures Easing Path to Carbon Sequestration, Transport*, 40 Env't Rep. (BNA) 1202 (May 22, 2009).
394. GAO, *supra* note 45, at 45.
395. Christopher Van Atten et al., *Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States* 9 (June 2010), *available at* http://www.nrdc.org.
396. *Id.* at 9, 12.
397. *Id.* at 12.
398. U.S. Energy Information Administration, Natural Gas Weekly Update (Nov. 3, 2010), *available at* http://tonto.eia.doe.gov/oog/info/ngw/ngupdate.asp.
399. Van Atten et al., *supra* note 395, at 13.
400. *See generally* Lincoln L. Davies, *Power Forward: The Argument for a National RPS*, 42 Conn. L. Rev. 1339 (2010).
401. Van Atten et al., *supra* note 395, at 15.