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Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy

Peter Folger

Specialist in Energy and Natural Resources Policy

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Summary

On September 20, 2013, the U.S. Environmental Protection Agency (EPA) re-proposed standards for carbon dioxide (CO₂) emissions from new fossil-fueled power plants. On January 8, 2014, EPA published the re-proposed rule in the *Federal Register*, triggering the start of a 60-day public comment period. The proposed rule places a new focus on whether the U.S. Department of Energy's (DOE's) CCS research, development, and demonstration (RD&D) program will achieve its vision of developing an advanced CCS technology portfolio ready by 2020 for large-scale CCS deployment.

As re-proposed, the standards would limit emissions of CO₂ to no more than 1,100 pounds per megawatt-hour (lbs/Mwh) of production from new coal-fired power plants and between 1,000 and 1,100 lbs/Mwh (depending on size of the plant) for new natural gas-fired plants. EPA proposed the standard under Section 111 of the Clean Air Act. According to EPA, new natural gas-fired stationary power plants should be able to meet the proposed standards without additional cost and the need for add-on control technology. However, new coal-fired plants only would be able to meet the standards by installing carbon capture and sequestration (CCS) technology. The re-proposed rule has sparked increased scrutiny of the future of CCS as a viable technology for reducing CO₂ emissions from coal-fired power plants.

Congress appropriated \$3.4 billion from the American Recovery and Reinvestment Act (Recovery Act) for CCS RD&D at DOE's Office of Fossil Energy in addition to annual appropriations for CCS. The large influx of funding for industrial-scale CCS projects was intended to accelerate development and deployment of CCS in the United States. Since enactment of the Recovery Act, DOE has shifted its RD&D emphasis to the demonstration phase of carbon capture technology. To date, however, there are no commercial ventures in the United States that capture, transport, and inject industrial-scale quantities of CO₂ solely for the purposes of carbon sequestration.

The success of DOE CCS demonstration projects will likely influence the future outlook for widespread deployment of CCS technologies as a strategy for preventing large quantities of CO₂ from reaching the atmosphere while U.S. power plants continue to burn fossil fuels, mainly coal. One project, the Kemper County Facility, has received \$270 million from DOE under its Clean Coal Power Initiative Round 2 program, and is slated to begin commercial operation in late 2014. The 583 megawatt capacity facility anticipates capturing 65% of its CO₂ emissions, making it equivalent to a new natural gas-fired combined cycle power plant. Cost overruns at the Kemper Plant, however, have raised questions over the relative value of environmental benefits due to CCS technology compared to construction costs of the facility and its effect on ratepayers.

Given the pending EPA rule, congressional interest in the future of coal as a domestic energy source appears directly linked to the future of CCS. Following the September 20, 2013, re-proposal of the rule the debate has been mixed as to whether the rule would spur development and deployment of CCS for new coal-fired power plants or have the opposite effect. Several bills introduced in the House and Senate, such as H.R. 3826 and S. 1905, directly address EPA's authority to issue regulations curtailing CO₂ emissions from coal-fired power plants. Congressional oversight of the CCS RD&D program could help inform decisions about the level of support for the program and help Congress gauge whether it is on track to meet its goals.

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Introduction

Carbon capture and sequestration (or storage)—known as CCS—is a physical process that involves capturing manmade carbon dioxide (CO₂) at its source and storing it before its release to the atmosphere. CCS could reduce the amount of CO₂ emitted to the atmosphere while allowing the continued use of fossil fuels at power plants and other large, industrial facilities. An integrated CCS system would include three main steps: (1) capturing CO₂ at its source and separating it from other gases; (2) purifying, compressing, and transporting the captured CO₂ to the sequestration site; and (3) injecting the CO₂ into subsurface geological reservoirs. Following its injection into a subsurface reservoir, the CO₂ would need to be monitored for leakage and to verify that it remains in the target geological reservoir. Once injection operations cease, a responsible party would need to take title to the injected CO₂ and ensure that it stays underground in perpetuity.

The U.S. Department of Energy (DOE) has pursued research and development of aspects of the three main steps leading to an integrated CCS system since 1997.¹ Congress has appropriated approximately \$6 billion in total since FY2008 for CCS research, development, and demonstration (RD&D) at DOE's Office of Fossil Energy: approximately \$3 billion in total annual appropriations (including FY2014), and \$3.4 billion from the American Recovery and Reinvestment Act (P.L. 111-5, enacted February 17, 2009, hereinafter referred to as the Recovery Act).

The large and rapid influx of funding for industrial-scale CCS projects from the Recovery Act was intended to accelerate development and demonstration of CCS in the United States. The Recovery Act funding also was likely intended to help DOE achieve its RD&D goals as outlined in the department's 2010 RD&D *CCS Roadmap*.² (In part, the roadmap was intended to lay out a path for rapid technological development of CCS so that the United States would continue to use fossil fuels.) However, the future deployment of CCS may take a different course if the major components of the DOE program follow a path similar to DOE's FutureGen project, which has experienced delays and multiple changes of scope and design since its inception in 2003.³

This report aims to provide a snapshot of the DOE CCS program, including its current funding levels, together with some discussion of the program's achievements and prospects for success in meeting its stated goals. Other CRS reports provide substantial detail on the technological and policy aspects of CCS.⁴

¹ U.S. Department of Energy, National Energy Technology Laboratory, *Carbon Sequestration Program: Technology Program Plan*, Enhancing the Success of Carbon Capture and Storage Technologies, February 2011, p. 10, http://www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf.

² U.S. Department of Energy, National Energy Technology Laboratory, *DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap*, December 2010. Hereinafter referred to as the DOE 2010 *CCS Roadmap*. See <http://www.netl.doe.gov/File%20Library/Research/Carbon%20Seq/Reference%20Shelf/CCSRoadmap.pdf>.

³ As originally conceived in 2003, FutureGen would have been a 10-year project to build a coal-fired power plant that would integrate carbon sequestration and hydrogen production while producing 275 megawatts of electricity, enough to power about 150,000 average U.S. homes. The plant would have been a coal-gasification facility and would have produced and sequestered between 1 million and 2 million tons of CO₂ annually. FutureGen 2.0 differs from the original concept for the plant, because it would retrofit an existing power plant in Meredosia, IL, with oxy-combustion technology, and is funded largely by appropriations made available by the Recovery Act. See CRS Report R43028, *The FutureGen Carbon Capture and Sequestration Project: A Brief History and Issues for Congress*, by Peter Folger

⁴ See, for example, CRS Report R42532, *Carbon Capture and Sequestration (CCS): A Primer*; CRS Report R41325, (continued...)

EPA Proposed Rule: Limiting CO₂ Emissions from Power Plants⁵

New Power Plants

On September 20, 2013, the U.S. Environmental Protection Agency (EPA) re-proposed a standard that would limit emissions of carbon dioxide (CO₂) from new fossil-fueled power plants. As re-proposed, the rule would limit emissions to no more than 1,100 pounds per megawatt-hour of electric generation from new coal-fired power plants and between 1,000 and 1,100 pounds per megawatt-hour (depending on size of the plant) for new natural gas-fired plants. EPA proposed the standard under Section 111 of the Clean Air Act. According to EPA, new natural gas-fired stationary power plants should be able to meet the proposed standard without additional cost and the need for add-on control technology. However, the only technical way for new coal-fired plants to meet the standard would be to install carbon capture and sequestration (CCS) technology to capture about 40% of the CO₂ they typically produce. The proposed standard allows for a seven-year compliance period for coal-fired plants but would demand a more stringent standard for those plants that comply over seven years; CO₂ emissions for these plants would be limited to an average of 1,000-1,050 pounds per megawatt-hour.⁶

On January 8, 2014, EPA published the re-proposed rule in the *Federal Register*.⁷ Publishing in the *Federal Register* triggers the start of a 60-day public comment period: Comments will be accepted until March 10, 2014. The 2012 proposal generated more than 2.5 million comments, which prompted, in part, the September 20, 2013, re-proposal. Promulgation of the final rule could be expected sometime after the public comment period ends and EPA evaluates the comments.

The prospects for building new coal-fired electricity generating plants depend on many factors, such as costs of competing fuel sources (e.g., natural gas), electricity demand, regulatory costs, infrastructure (including rail) and electric grid development, and others. However, the EPA proposed rule clearly identifies CCS as the essential technology required if new coal-fired power plants are to be built in the United States.⁸ The re-proposed standard places a new focus on DOE's CCS RD&D program—whether it will achieve its vision of “having an advanced CCS technology portfolio ready by 2020 for large-scale CCS demonstration that provides for the safe, cost-effective carbon management that will meet our Nation’s goals for reducing [greenhouse gas] emissions.”⁹

(...continued)

Carbon Capture: A Technology Assessment.

⁵ For a fuller discussion of the proposed rule and EPA standards for greenhouse gas emissions from power plants, see CRS Report R43127, *EPA Standards for Greenhouse Gas Emissions from Power Plants: Many Questions, Some Answers*, by James E. McCarthy.

⁶ The proposal and background information is available at <http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants>.

⁷ Environmental Protection Agency, “Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units,” 79 *Federal Register* 1429, January 8, 2014.

⁸ *Ibid.*

⁹ DOE 2010 *CCS Roadmap*, p. 3.

Existing Power Plants

The September 2013 re-proposed rule would address only new power plants. However, Section 111 of the Clean Air Act requires that EPA develop guidelines for greenhouse gas emissions for existing plants whenever it promulgates standards for new power plants. In his June 25, 2013, memorandum, President Obama directed the EPA to issue proposed guidelines for existing plants by June 1, 2014, and to issue final guidelines a year later.¹⁰

Implications for CCS Research, Development, and Deployment

Congress has appropriated funding for DOE to pursue CCS research and development since 1997 and signaled its interest in CCS technology by awarding \$3.4 billion from the Recovery Act to CCS programs at DOE. Given the pending EPA rule, congressional interest in the future of coal as a domestic energy source appears directly linked to the future of CCS. Following the September 20, 2013, re-proposal of the rule, the debate has been mixed as to whether the rule would spur development and deployment of CCS for new coal-fired power plants or have the opposite effect. Multiple analyses indicate that there will be retirements of U.S. coal-fired capacity; however, virtually all analyses agree that coal will continue to play a substantial role in electricity generation for decades. How many retirements would take place and the role of EPA regulations in causing them are matters of dispute.¹¹

Since the September 2013 re-proposal, the argument over the rule has focused, in part, on whether CCS is the best system of emissions reduction (BSER) for coal plants and whether it has been “adequately demonstrated” as such as required under the Clean Air Act. In its re-proposed rule, EPA cites the “existence and apparent ongoing viability” of several ongoing CCS demonstration projects as examples that justify a separate determination of BSER for coal-fired plants and integrated gasification combined-cycle plants. (The second BSER determination is for gas-fired power plants.)¹² The EPA noted that these projects had reached advanced stages of construction and development, “which suggests that proposing a separate standard for coal-fired units is appropriate.”

The Natural Gas Alternative?

The huge increases in the U.S. domestic supply of natural gas in recent years, due largely to the exploitation of unconventional shale gas reservoirs through the use of hydraulic fracturing, has also led to a shift to natural gas for electricity production.¹³ The shift appears to be largely due to the cheaper and increasingly abundant fuel—natural gas—compared to coal for electricity

¹⁰ Office of the Press Secretary, The White House, “Power Sector Carbon Pollution Standards,” Memorandum for the Administrator of the Environmental Protection Agency, June 25, 2013, <http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards>.

¹¹ For a detailed discussion of the EPA’s regulation of coal, see CRS Report R41914, *EPA’s Regulation of Coal-Fired Power: Is a “Train Wreck” Coming?*, by James E. McCarthy and Claudia Copeland.

¹² The projects cited in the re-proposed rule are the Southern Company Kemper County Energy Facility, the SaskPower Boundary Dam CCS project, the Summit Power Texas Clean Energy Project, and the Hydrogen Energy California Project. The Boundary Dam project is a Canadian venture; the other three projects are in the United States and are receiving funding from DOE.

¹³ For a detailed discussion of how natural gas is affecting electric power generation, see CRS Report R42814, *Natural Gas in the U.S. Economy: Opportunities for Growth*, by Robert Pirog and Michael Ratner.

production. The EPA re-proposed rule, discussed above, noted that “power companies often choose the lowest cost form of generation when determining what type of new generation to build. Based on [Energy Information Administration] modeling and utility [Integrated Resource Plans], there appears to be a general acceptance that the lowest cost form of new power generations is [natural gas combined-cycle].” Cheap gas, due to the rapid increase in the domestic natural gas supply as an alternative to coal, in combination with regulations that curtail CO₂ emissions may lead electric power producers to invest in natural gas-fired plants, which emit approximately half the amount of CO₂ per unit of electricity produced compared to coal-fired plants. Regulations and abundant cheap gas may raise questions about the rationale for funding CCS demonstration projects like FutureGen.

Alternatively, and despite increasingly abundant domestic natural gas supplies, EPA regulations could provide the necessary incentives for the industry to accelerate CCS development and deployment for coal-fired power plants. As part of its re-proposed ruling, EPA cites technology as one of four factors that it considers in making a BSER determination.¹⁴ Specifically, EPA stated that it “considers whether the system promotes the implementation and further development of technology,” in this case referring to CCS technology. It appears that EPA asserts that its rule would likely promote CCS development and deployment rather than hinder it. Those arguing against the re-proposed rule do so on the basis that CCS technology has not been adequately demonstrated, and that it violates provisions in P.L. 109-58, the Energy Policy Act of 2005, that prohibit EPA from setting a performance standard based on the use of technology from certain DOE-funded projects, such as the three projects cited in the EPA re-proposal, among other reasons.¹⁵

Legislation

Although DOE has pursued aspects of CCS RD&D since 1997, the Energy Policy Act of 2005 (P.L. 109-58) provided a 10-year authorization for the basic framework of CCS research and development at DOE.¹⁶ The Energy Independence and Security Act of 2007 (EISA, P.L. 110-140) amended the Energy Policy Act of 2005 to include, among other provisions, authorization for seven large-scale CCS demonstration projects (in addition to FutureGen) that would integrate the carbon capture, transportation, and sequestration steps.¹⁷ (Large-scale demonstration programs and their potential significance are discussed below.) It can be argued that, since enactment of EISA, the focus and funding within the CCS RD&D program has shifted toward large-scale capture technology development through these and other demonstration projects.

In addition to the annual appropriations provided for CCS RD&D, the Recovery Act (P.L. 111-5) has been the most significant legislation that promotes and supports federal CCS RD&D program activities since passage of EISA. As discussed below, \$3.4 billion in funding from the Recovery

¹⁴ The other three are feasibility, costs, and size of emission reductions.

¹⁵ See for example, the November 15, 2013, letter to EPA Administrator Gina McCarthy from Representative Fred Upton, chair of the House Committee on Energy and Commerce, http://www.eenews.net/assets/2013/11/22/document_daily_03.pdf; and the December 19, 2013, letter to Administrator McCarthy from Representative Lamar Smith, chair of the House Committee on Science, Space, and Technology, http://science.house.gov/sites/repUBLICans.science.house.gov/files/documents/Letters/121913_mccarthy.pdf.

¹⁶ P.L. 109-58, Title IX, Subtitle F, §963; 42 U.S.C. 16293.

¹⁷ P.L. 110-140, Title VII, Subtitles A and B.

Act was intended to expand and accelerate the commercial deployment of CCS technologies to allow for commercial-scale demonstration in both new and retrofitted power plants and industrial facilities by 2020.

113th Congress

As introduced on January 9, 2014, H.R. 3826, the Electricity Security and Affordability Act, would essentially set requirements EPA must meet before the agency could issue greenhouse gas emission regulations under Section 111 of the Clean Air Act, such as the EPA re-proposed rule discussed above. On January 14, 2014, the Energy and Power Subcommittee, House Energy and Commerce Committee, voted to report the bill. Much of the discussion during the bill's markup centered on whether CCS was an adequately demonstrated technology to meet the requirements of the Clean Air Act. On January 28, 2014, the full committee voted to report the bill. Companion legislation, S. 1905, was introduced on January 9, 2014, and referred to the Senate Committee on Environment and Public Works.

A bill introduced on May 23, 2013, H.R. 2127, would prohibit the EPA from finalizing any rule limiting the emission of CO₂ from any existing or new source that is a fossil fuel-fired electric utility generating unit unless and until CCS becomes technologically and economically feasible. Other bills that target the EPA's proposed rule on limiting CO₂ emissions from new power plants were introduced shortly before and after the September 20, 2013, rule was proposed, including H.J.Res. 64, H.R. 3140, S. 1514, and others.

112th Congress

In the 112th Congress, a few bills were introduced that would have addressed aspects of CCS RD&D. The Department of Energy Carbon Capture and Sequestration Program Amendments Act of 2011 (S. 699) would have provided federal indemnification of up to \$10 billion per project to early adopters of CCS technology (large CCS demonstration projects).¹⁸ The New Manhattan Project for Energy Independence (H.R. 301) would have created a system of grants and prizes for a variety of technologies, including CCS, that would contribute to reducing U.S. dependence on foreign sources of energy. Other bills introduced would have provided tax incentives for the use of CO₂ in enhanced oil recovery (S. 1321), or would have eliminated the minimum capture requirement for the CO₂ sequestration tax credit (H.R. 1023). Other bills were also introduced that would have affected other aspects of CCS RD&D financing, such as loan guarantees. None of the bills introduced in the 112th Congress affecting federal CCS RD&D, other than the continuing resolution (CR), was enacted.

111th Congress

In the 111th Congress, two bills that would have authorized a national cap-and-trade system for limiting the emission of greenhouse gases (H.R. 2454 and S. 1733) also would have created programs aimed at accelerating the commercial availability of CCS. The programs would have generated funding from a surcharge on electricity delivered from the combustion of fossil fuels—

¹⁸ Among other provisions, the bill would also have amended EISA to expand the number of large CCS demonstration projects from 7 to 10.

approximately \$1 billion per year—and made the funding available for grants, contracts, and financial assistance to eligible entities seeking to develop CCS technology. Another source of funding in the bills was to come from a program that would distribute emission allowances to “early movers,” entities that installed CCS technology on up to a total of 20 gigawatts of generating capacity. The House of Representatives passed H.R. 2454, but neither bill was enacted.

CCS Research, Development, and Demonstration: Overall Goals

The U.S. Department of Energy states that the mission for the DOE Office of Fossil Energy is “to ensure the availability of ultra-clean (near-zero emissions), abundant, low-cost domestic energy from coal to fuel economic prosperity, strengthen energy security, and enhance environmental quality.”¹⁹ Over the past several years, the DOE Fossil Energy Research and Development Program has increasingly shifted activities performed under its Coal Program toward emphasizing CCS as the main focus.²⁰ The Coal Program represented 69% of total Fossil Energy Research and Development appropriations in FY2012 and in FY2013,²¹ and represents nearly 70% in the FY2014 appropriation,²² indicating that CCS has come to dominate coal R&D at DOE. This reflects DOE’s view that “there is a growing consensus that steps must be taken to significantly reduce [greenhouse gas] emissions from energy use throughout the world at a pace consistent to stabilize atmospheric concentrations of CO₂, and that CCS is a promising option for addressing this challenge.”²³

DOE also acknowledges that the cost of deploying currently available CCS technologies is very high, and that to be effective as a technology for mitigating greenhouse gas emissions from power plants, the costs for CCS must be reduced. For example, in 2010 DOE stated that the cost of deploying available CCS post-combustion technology on a supercritical pulverized coal-fired power plant would increase the cost of electricity by 80%.²⁴ The challenge of reducing the costs of CCS technology is difficult to quantify, in part because there are no examples of currently operating commercial-scale coal-fired power plants equipped with CCS. Nor is it easy to predict when lower-cost CCS technology will be available for widespread deployment in the United States. Nevertheless, DOE observes that “the United States can no longer afford the luxury of conventional long-lead times for RD&D to bear results.”²⁵ Thus the coal RD&D program is

¹⁹ DOE 2010 *CCS Roadmap*, p. 2.

²⁰ The Coal Program contains CCS RD&D activities, and is within DOE’s Office of Fossil Energy, Fossil Energy Research and Development, as listed in DOE detailed budget justifications for each fiscal year. See, for example, U.S. Department of Energy, FY2014 Congressional Budget Request, volume 3, *Fossil Energy Research and Development*, http://energy.gov/sites/prod/files/2013/04/f0/Volume3_1.pdf. The percentage of funding allocated to the Coal Program is calculated based on the subtotal for Fossil Energy Research and Development prior to rescission of prior year balances, which were \$187 million for FY2012 and \$42 million for FY2013, respectively.

²¹ U.S. Department of Energy, FY2013 Congressional Budget Request, volume 3, *Fossil Energy Research and Development*, p. 411.

²² FY2014 Joint Explanatory Statement in the Congressional Record, January 15, 2014, and P.L. 113-76.

²³ DOE 2010 *CCS Roadmap*, p. 3.

²⁴ DOE 2010 *CCS Roadmap*, p. 3.

²⁵ DOE 2010 *CCS Roadmap*, p. 3.

focused on achieving results that would allow for an advanced CCS technology portfolio to be ready by 2020 for large-scale demonstration.

The following section describes the components of the CCS activities within DOE's coal R&D program and their funding history since FY2012. This report focuses on this time period because during that time DOE obligated Recovery Act funding for its CCS programs, greatly expanding the CCS R&D portfolio. This was expected to accelerate the transition of CCS technology to industry for deployment and commercialization.²⁶ In addition, one remaining active project in the Clean Coal Power Initiative (CCPI) program that received funding in Round 2, prior to enactment of the Recovery Act—the Kemper County Energy Facility—is also discussed.

Program Areas

The 2010 RD&D *CCS Roadmap* described 10 different program areas pursued by DOE's Coal Program within the Office of Fossil Energy: (1) Innovations for Existing Plants (IEP); (2) Advanced Integrated Gasification Combined Cycle (IGCC); (3) Advanced Turbines; (4) Carbon Sequestration; (5) Solid State Energy Conversion Fuel Cells; (6) Fuels; (7) Advanced Research; (8) Clean Coal Power Initiative (CCPI); (9) FutureGen; and (10) Industrial Carbon Capture and Storage Projects (ICCS).²⁷

DOE changed the program structure after FY2010, renaming and consolidating program areas. The program areas are divided into two main categories: (1) CCS Demonstration Programs, and (2) Carbon Capture and Storage, and Power Systems. **Table 1** shows the current program structure and indicates which programs received Recovery Act funding. In its FY2014 Budget Justification, DOE stated that the mission of these program areas is

to support secure, affordable, and environmentally acceptable near-zero emissions fossil energy technologies. This will be accomplished via research, development, and demonstration to improve the performance of advanced CCS technologies. Commercial availability of CCS technologies will provide an option to use fossil fuel resources to provide energy and meet the President's climate goals.²⁸

Some programs are directly focused on one or more of the three steps of CCS: capture, transportation, and storage. For example, the carbon capture program supports R&D on post-combustion, pre-combustion, and natural gas capture. The carbon storage program supports the regional carbon sequestration partnerships, geological storage technologies, and other aspects of permanently sequestering CO₂ underground. In contrast, FutureGen from the outset was envisioned as combining all three steps: a zero-emission fossil fuel plant that would capture its emissions and sequester them in a geologic reservoir.

²⁶ DOE 2010 *CCS Roadmap*, p. 2.

²⁷ DOE 2010 *CCS Roadmap*, p. 11.

²⁸ U.S. Department of Energy, FY2014 Congressional Budget Request, volume 3, *Fossil Energy Research and Development*, p. FE-13.

Table I. DOE Carbon Capture and Storage Research, Development, and Demonstration Program Areas

(funding in \$ thousands, FY2012-FY2014, including Recovery Act funding)

Fossil Energy Research and Development Coal Program Areas	Program	Recovery Act	FY2012	FY2013 (annualized CR) ^a	FY2014 (Request)	P.L. 113-76
CCS Demonstrations	FutureGen 2.0	1,000,000	0	0	0	0
	Clean Coal Power Initiative (CCPI)	800,000	0	0	0	0
	Industrial Carbon Capture and Storage Projects (ICCS)	1,520,000	0	0	0	0
	Site Characterization, Training, Program Direction	80,000	0	0	0	0
Carbon Capture and Storage, and Power Systems	Carbon Capture	—	66,986	65,600	112,000	92,000
	Advanced Energy Systems	—	97,169	95,200	48,000	99,500
	Carbon Storage	—	112,208	109,900	61,095	108,900
	Cross Cutting Research	—	47,946	46,800	20,525	41,900
	NETL Coal Research and Development	—	35,011	33,300	35,011	50,000
		3,400,000	359,320	350,800	276,631	392,300

Source: U.S. Department of Energy, FY2013 Congressional Budget Request, volume 3, *Fossil Energy Research and Development*, http://energy.gov/sites/prod/files/2013/04/f0/Volume3_1.pdf. U.S. Department of Energy, Carbon Sequestration, *Recovery Act*, <http://www.fe.doe.gov/recovery/index.html>; U.S. Department of Energy, FY2014 Congressional Budget Request, volume 3, *Fossil Energy Research and Development*, http://energy.gov/sites/prod/files/2013/04/f0/Volume3_1.pdf; FY2014 Joint Explanatory Statement in the Congressional Record, January 15, 2014, and P.L. 113-76.

a. According to DOE, the FY2013 column amounts reflect the continuing resolution (CR, P.L. 112-175) levels annualized to a full year. Figures reflect the March 1, 2013, sequester of funds under P.L. 112-25.

Within the CCS Demonstration Program Area, RD&D is also divided among different industrial sectors. The Clean Coal Power Initiative (CCPI) program area originally provided federal support to new coal technologies that helped power plants cut sulfur, nitrogen, and mercury pollutants. As CCS became the focus of coal RD&D, the CCPI program shifted to reducing greenhouse gas emissions by boosting plant efficiencies and capturing CO₂.²⁹ In contrast, the ICCS program area demonstrates carbon capture technology for the non-power plant industrial sector.³⁰ Both these program areas focus on the *demonstration* component of RD&D, and account for \$2.3 billion of the \$3.4 billion appropriated for CCS RD&D in the Recovery Act in FY2009. From the budgetary perspective, the Recovery Act funding shifted the emphasis of CCS RD&D to large, industrial demonstration projects for carbon capture. The CCPI and ICCS program areas are discussed in more detail below.

This shift in emphasis to the demonstration phase of carbon capture technology is not surprising, and appears to heed recommendations from many experts who have called for large, industrial-scale carbon capture demonstration projects.³¹ Primarily, the call for large-scale CCS demonstration projects that capture 1 million metric tons or more of CO₂ per year reflects the need to reduce the additional costs to the power plant or industrial facility associated with capturing the CO₂ before it is emitted to the atmosphere. The capture component of CCS is the costliest component, according to most experts.³² The higher estimated costs to build and operate power plants with CCS compared to plants without CCS, and the uncertainty in cost estimates, results in part from a dearth of information about outstanding technical questions in carbon capture technology at the industrial scale.³³

In comparative studies of cost estimates for other environmental technologies, such as for power plant scrubbers that remove sulfur and nitrogen compounds from power plant emissions (SO₂ and NO_x), some experts note that the farther away a technology is from commercial reality, the more uncertain is its estimated cost. At the beginning of the RD&D process, initial cost estimates could be low, but could typically increase through the demonstration phase before decreasing after successful deployment and commercialization. **Figure 1** shows a cost estimate curve of this type.

²⁹ Ibid., p. FE-16.

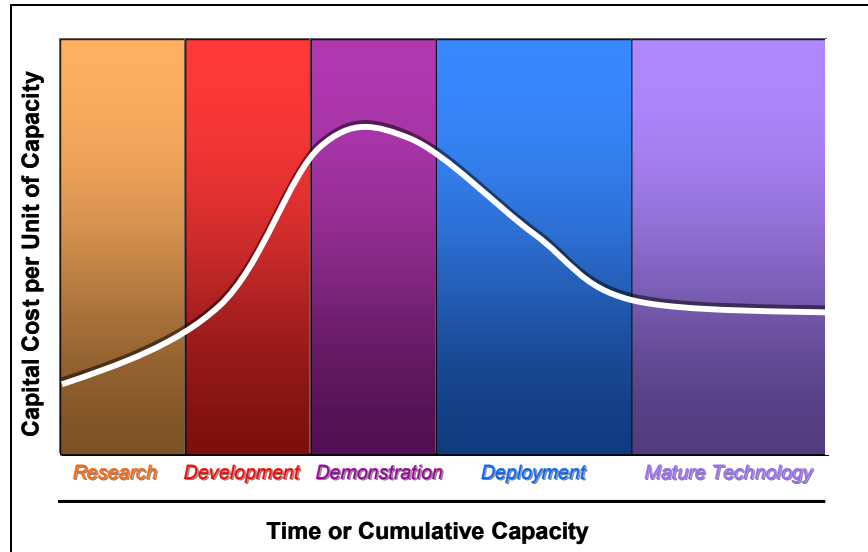
³⁰ DOE 2010 *CCS Roadmap*, p. 12.

³¹ See, for example, the presentations given by Edward Rubin of Carnegie Mellon University, Howard Herzog of the Massachusetts Institute of Technology, and Jeff Phillips of the Electric Power Research Institute, at the CRS seminar *Capturing Carbon for Climate Control: What's in the Toolbox and What's Missing*, November 18, 2009. (Presentations available from Peter Folger at 7-1517.) Rubin stated that at least 10 full-scale demonstration projects would be needed to establish the reliability and true cost of CCS in power plant applications. Herzog also called for at least 10 demonstration plants worldwide that capture and sequester a million metric tons of CO₂ per year. In his presentation, Phillips stated that large-scale demonstrations are critical to building confidence among power plant owners.

³² For example, an MIT report estimated that the costs of capture could be 80% or more of the total CCS costs. John Deutsch et al., *The Future of Coal*, Massachusetts Institute of Technology, An Interdisciplinary MIT Study, 2007, Executive Summary, p. xi.

³³ *The Future of Coal*, p. 97.

Figure 1. Typical Trend in Cost Estimates for a New Technology As It Develops from a Research Concept to Commercial Maturity



Source: Adapted from S. Dalton, “CO₂ Capture at Coal Fired Power Plants—Status and Outlook,” 9th International Conference on Greenhouse Gas Control Technologies, Washington, DC, November, 16-20, 2008.

Deploying commercial-scale CCS demonstration projects—an emphasis within the DOE CCS RD&D program—would therefore provide cost estimates closer to operational conditions rather than laboratory- or pilot-plant-scale projects. In the case of SO₂ and NO_x scrubbers, efforts typically took two decades or more to bring new concepts (such as combined SO₂ and NO_x capture systems) to the commercial stage. As **Figure 1** indicates, costs for new technologies tend to fall over time with successful deployment and commercialization. It would be reasonable to expect a similar trend for CO₂ capture costs if the technologies become widely deployed.³⁴

First Full-Scale Project? The Kemper County Energy Facility

In a fact sheet accompanying the proposed rule limiting emissions of CO₂ from new coal-fired power plants, the EPA asserts that CCS technology is currently feasible and refers to a coal-gasification project that is over 75% complete: the Kemper County Project. DOE awarded Southern Company Services a cooperative agreement under the CCPI Round 2 program, prior to enactment of the Recovery Act and the CCPI Round 3 awards, to develop technology at the Kemper County Energy Facility in Kemper County, Mississippi. The \$270 million award was aimed to provide direct financial support for the development and deployment of a gasification technology called Transport Integrated Gasification (TRIGTM).³⁵

The Kemper County Project is an integrated gasification combined-cycle (IGCC)³⁶ power plant that will be owned and operated by Mississippi Power Company, a subsidiary of Southern

³⁴ For a fuller discussion of the relationship between costs of developing technologies analogous to CCS, such as SO₂ and NO_x scrubbers, see CRS Report R41325, *Carbon Capture: A Technology Assessment*, by Peter Folger.

³⁵ NETL Fact Sheet, “Demonstration of a Coal-Based Transport Gasifier,” Fact Sheet NT42391, March 2013, <http://www.netl.doe.gov/publications/factsheets/project/NT42391.pdf>.

³⁶ For more information on IGCC power plants and CCS, see CRS Report R41325, *Carbon Capture: A Technology Assessment*, by Peter Folger.

Company, and which will use lignite as a fuel source. The plant is expected to have an estimated peak net output capability of 583 megawatts, and is designed to capture 65% of the total CO₂ emissions released from the plant.³⁷ According to DOE, this would make the CO₂ emissions from the Kemper Project comparable to a natural gas-fired combined cycle power plant, and would therefore emit less than the 1,100 pounds per MWh limit as required by the new EPA proposed rule. The estimated 3 million tons of CO₂ captured each year from the plant would be transported via newly constructed pipeline for use in enhanced oil recovery operations at nearby depleted oil fields in Mississippi. Commercial operation of the Kemper County Project is expected to begin in 2014, according to Southern Company.³⁸

The \$270 million award under Round 2 of the CCPI program represents less than 10% of the overall cost to build the plant, which is reported to be approximately \$3 billion, according to a March 2013 DOE fact sheet.³⁹ However, in April 2013 the company announced that capital costs would be closer to \$3.4 billion, approximately \$1 billion higher than original cost estimates for the plant.⁴⁰ In December 2013, Mississippi Power released documents indicating that the project was on schedule to begin operations in the last quarter of 2014, but that the total cost for the plant, including the lignite mine, CO₂ pipeline, land purchase, and all the other components of the full project, was approximately \$5 billion.⁴¹

It is likely that the plant will attract increased scrutiny in the wake of the EPA proposed rule on CO₂ emissions, and its cost overruns evaluated against the promised environmental benefits due to CCS technology.⁴² As **Figure 1** shows above, costs for technologies tend to peak for projects in the demonstration phase of development, such as the Kemper County Project. What the cost curve will look like, namely, how fast costs will decline and over what time period, is an open question and will likely depend on if and how quickly CCS technology is deployed on new and existing power plants.

Recovery Act Funding for CCS Projects: A Lynchpin for Success?

The bulk of Recovery Act funds for CCS (\$3.32 billion, or 98%) was directed to three subprograms organized under the CCS Demonstrations Programs: the Clean Coal Power Initiative (CCPI), Industrial Carbon Capture and Storage projects (ICCS), and FutureGen (**Table**

³⁷ NETL Fact Sheet, "Demonstration of a Coal-Based Transport Gasifier," Fact Sheet NT42391, March 2013, <http://www.netl.doe.gov/publications/factsheets/project/NT42391.pdf>.

³⁸ Mississippi Power, A Southern Company, "Kemper County Energy Facility, Kemper Timeline," <http://www.mississippipower.com/kemper/project-timeline.asp>.

³⁹ NETL Fact Sheet, "Demonstration of a Coal-Based Transport Gasifier," Fact Sheet NT42391, March 2013, <http://www.netl.doe.gov/publications/factsheets/project/NT42391.pdf>.

⁴⁰ Tamar Hallerman, "Miss. Power to Absorb \$540M in Cost Increases from Kemper Plant," *GHG Reduction Technologies Monitor*, April 26, 2013, <http://ghgnews.com/index.cfm/miss-power-to-absorb-540m-in-cost-increases-from-kemper-plant/>. Other reports cite the total costs for the plant.

⁴¹ See Mississippi Power, Kemper IGCC Project, Monthly Status Report Through December 2013, <http://www.sec.gov/Archives/edgar/data/66904/00000921221400002/msmonthlyreport8-kex99x01.htm>.

⁴² See, for example, Mark Drajem, "Mississippi's Kemper Coal Plant Overruns Show Risk of EPA Carbon Rule," *Bloomberg News, SunHerald.com*, September 19, 2013, <http://www.sunherald.com/2013/09/19/4964367/kemper-county-coal-plant-overruns.html>.

1). Under the 2010 *CCS Roadmap*, and with the large infusion of funding from the Recovery Act, DOE's goal is to develop the technologies to allow for commercial-scale demonstration in both new and retrofitted power plants and industrial facilities by 2020. The DOE 2011 *Strategic Plan* sets a more specific target: to bring at least five commercial-scale CCS demonstration projects online by 2016.⁴³

It could be argued that in its allocation of Recovery Act funding, DOE was heeding the recommendations of experts⁴⁴ who identified commercial-scale demonstration projects as the most important component, the lynchpin, for future development and deployment of CCS in the United States. It could also be argued that much of the future success of CCS is riding on these three programs. Accordingly, the following section provides a snapshot of the CCPI, ICCS, and FutureGen programs, and a brief discussion of some of their accomplishments and challenges.

CCS Demonstrations: CCPI, ICCS, and FutureGen 2.0

Clean Coal Power Initiative

The Clean Coal Power Initiative was an ongoing program prior to the \$800 million funding increase from the Recovery Act. This funding now is being used to expand activities in this program area for CCPI Round 3 beyond developing technologies to reduce sulfur, nitrogen, and mercury pollutants from power plants.⁴⁵ After enactment of the Recovery Act, DOE did not request additional funding for CCPI under its Fossil Energy program in the annual appropriations process (**Table 1** shows zero dollars for FY2012-FY2014). Rather, in the FY2010 DOE budget justification, DOE stated that funding for the these projects in CCPI Round 3 would be supported through the Recovery Act, and as a result "DOE will make dramatic progress in demonstrating CCS at commercial scale using these funds without the need for additional resources for demonstration in 2010."⁴⁶

According to the 2010 DOE *CCS Roadmap*, Recovery Act funds are being used for these demonstration projects to "allow researchers broader CCS commercial-scale experience by expanding the range of technologies, applications, fuels, and geologic formations that are being tested."⁴⁷ DOE selected six projects under CCPI Round 3 through two separate solicitations.⁴⁸

⁴³ U.S. Department of Energy, *Strategic Plan*, May 2011, p. 18, http://energy.gov/sites/prod/files/2011_DOE_Strategic_Plan_.pdf.

⁴⁴ See, for example, the presentations given by Edward Rubin of Carnegie Mellon University, Howard Herzog of the Massachusetts Institute of Technology, and Jeff Phillips of the Electric Power Research Institute, at the CRS seminar *Capturing Carbon for Climate Control: What's in the Toolbox and What's Missing*, November 18, 2009. (Presentations available from Peter Folger at 7-1517.) Rubin stated that at least 10 full-scale demonstration projects would be needed to establish the reliability and true cost of CCS in power plant applications. Herzog also called for at least 10 demonstration plants worldwide that capture and sequester a million metric tons of CO₂ per year. In his presentation, Phillips stated that large-scale demonstrations are critical to building confidence among power plant owners.

⁴⁵ DOE had solicited and awarded funding for CCPI projects in two previous rounds of funding: CCPI Round 1 and Round 2. The Recovery Act funds were to be allocated CCPI Round 3, focusing on projects that utilize CCS technology and/or the beneficial reuse of CO₂. For more details, see <http://www.fossil.energy.gov/programs/powersystems/cleancoal/>.

⁴⁶ U.S. Department of Energy, *Detailed Budget Justifications FY2010*, volume 7, Fossil Energy Research and Development, p. 35, <http://www.cfo.doe.gov/budget/10budget/Content/Volumes/Volume7.pdf>.

⁴⁷ DOE 2010 *CCS Roadmap*, p. 15.

⁴⁸ The first solicitation closing date was January 20, 2009; the second solicitation closing date was August 24, 2009. Thus the first set of project proposals were submitted prior to enactment of the Recovery Act. See (continued...)

The total DOE share of funding would have been \$1.75 billion for the six projects in five states: Alabama, California, North Dakota, Texas, and West Virginia (**Table 2**). However, the projects in Alabama, North Dakota, and West Virginia withdrew from the program, and currently the DOE share for the remaining three projects is \$1.03 billion (of a total of over \$6 billion for total expected costs). With the withdrawal of three CCPI Round 3 projects, DOE's share of the total program costs shrank from over 22% to approximately 17%.

Table 2. DOE CCS Demonstration Round 3 Projects

Round 3 Project	Location	DOE Share of Funding (\$ millions)	Total Project Cost (\$ millions)	Percent DOE Share	Metric Tons of CO ₂ Captured Annually (millions)	Project Status
Texas Clean Energy Project	Penwell, TX	450	1,727	26%	2.7 ^b	Active
Hydrogen Energy California Project	Kern County, CA	408	4,028	10%	2.6	Active
NRG Energy Project	Thompsons, TX	167	338	50%	1.4	Active
AEP Mountaineer Project	New Haven, WV	334	668	50%	1.5	Withdrawn
Southern Company Project	Mobile, AL	295	665	44%	1	Withdrawn
Basin Electric Power Project	Beulah, ND	100	387	26%	0.9	Withdrawn
Total		1,754	7,813	22.4%	10.1	
Total, Active Projects^a		1,025	6,093	16.8%	6.7	

Sources: DOE Fossil Energy Techline; Environment News Service (March 12, 2010), <http://www.ens-newswire.com/ens/mar2010/2010-03-12-093.html>; NETL CCPI website, <http://www.netl.doe.gov/technologies/coalpower/cctc/ccpi/index.html>; NETL Factsheet: Summit Texas Clean Energy, LLC, March 2012, <http://www.netl.doe.gov/publications/factsheets/project/FE0002650.pdf>; NETL Factsheet Hydrogen Energy California Project, May 2013, <http://www.netl.doe.gov/publications/factsheets/project/FE0000663.pdf>; NETL Factsheet BRG Energy: W.A. Parish Post Combustion CO₂ Capture and Sequestration Project, March 2012, <http://www.netl.doe.gov/publications/factsheets/project/FE0003311.pdf>.

Notes: DOE funding for the NRG Energy Project was initially announced as up to \$154 million (see March 9, 2009, DOE Techline, http://www.fossil.energy.gov/news/techlines/2010/10005-NRG_Energy_Selected_to_Receive_DOE.html). A May 2010 DOE fact sheet indicates that funding for NRG is \$167 million (<http://www.netl.doe.gov/publications/factsheets/project/FE0003311.pdf>).

- a. Total include amounts that were reallocated from withdrawn projects to active projects.
- b. According to NETL, this amount could be up to 3 million metric tons annually.

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<http://www.fossil.energy.gov/programs/powersystems/cleancoal/>.

Reasons for Withdrawal from the CCPI Program

Commercial sector partners identified a number of reasons for withdrawing from the CCPI program, including finances, uncertainty regarding future regulations, and uncertainty regarding the future national climate policy.

Southern Company—Plant Barry 160 MW Project: Southern Company withdrew its Alabama Plant Barry project from the CCPI program on February 22, 2010, slightly more than two months after DOE Secretary Chu announced \$295 million in DOE funding for the 11-year, \$665 million project that would have captured up to 1 million tons of CO₂ per year from a 160 MW coal-fired generation unit.⁴⁹ According to some sources, Southern Company's decision was based on concern about the size of the company's needed commitment (approximately \$350 million) to the project, and its need for more time to perform due diligence on its financial commitment, among other reasons.⁵⁰ Southern Company continues work on a much smaller CCS project that would capture CO₂ from a 25 MW unit at Plant Barry.

Basin Electric Power—Antelope Valley 120 MW Project: On July 1, 2009, Secretary Chu announced \$100 million in DOE funding for a project that would capture approximately 1 million tons of CO₂ per year from a 120 MW electric-equivalent gas stream from the Antelope Valley power station near Beulah, ND.⁵¹ In December 2010, the Basin Electric Power Cooperative withdrew its project from the CCPI program, citing regulatory uncertainty with regard to capturing CO₂, uncertainty about the project's cost (one source indicates that the company estimated \$500 million total cost; DOE estimated \$387 million—see **Table 2**),⁵² uncertainty of environmental legislation, and lack of a long-term energy strategy for the country.⁵³ The project would have supplied the captured CO₂ to an existing pipeline that transports CO₂ from the Great Plains Synfuels Plant near Beulah for enhanced oil recovery in Canada's Weyburn field approximately 200 miles north in Saskatchewan.

American Electric Power—Mountaineer 235 MW Project: In July 2011 American Electric Power decided to halt its plans to build a carbon capture plant for a 235 MW generation unit at its 1.3 gigawatt Mountaineer power plant in New Haven, WV. The project represented Phase 2 of an ongoing CCPI project. Secretary Chu had earlier announced a \$334 million award for the project on December 4, 2009.⁵⁴ According to some sources, AEP dropped the project because the company was not certain that state regulators would allow it to recover the additional costs for the CCS project through rate increases charged to its customers.⁵⁵ In addition, company officials cited

⁴⁹ MIT Carbon Capture & Sequestration Technologies, *Plant Barry Fact Sheet: Carbon Dioxide Capture and Storage Project*, http://sequestration.mit.edu/tools/projects/plant_barry.html.

⁵⁰ Ibid.

⁵¹ U.S. DOE, Fossil Energy Techline, *Secretary Chu Announces Two New Projects to Reduce Emissions from Coal Plants*, July 1, 2009, http://www.fossil.energy.gov/news/techlines/2009/09043-DOE_Announces_CCPI_Projects.html.

⁵² Lauren Donovan, "Basin Shelves Lignite's First Carbon Capture Project," *Bismarck Tribune*, December 17, 2010, <http://bismarcktribune.com/news/local/a5fb7ed8-0a1b-11e0-b0ea-001cc4c03286.html>.

⁵³ Daryl Hill and Tracie Bettenhausen, "Fresh Tech, Difficult Decisions: Basin Electric has a History of Trying New Technology," Basin Electric Power Cooperative newsletter, January-February 2011, http://www.basinelectric.com/Miscellaneous/pdf/FeatureArticles/Fresh_Tech_difficul.pdf.

⁵⁴ U.S. DOE, Fossil Energy Techline, *Secretary Chu Announces \$3 Billion Investment for Carbon Capture and Sequestration*, December 4, 2009, http://www.fossil.energy.gov/news/techlines/2009/09081-Secretary_Chu_Announces_CCS_Invest.html.

⁵⁵ Matthew L. Wald and John M. Broder, "Utility Shelves Ambitious Plan to Limit Carbon," *New York Times*, July 13, (continued...)

broader economic and policy conditions as reasons for cancelling the project.⁵⁶ Some commentators suggested that congressional inaction on setting limits on greenhouse gas emissions, as well as the weak economy, may have diminished the incentives for a company like AEP to invest in CCS.⁵⁷ One source concluded that “Phase 2 has been cancelled due to unknown climate policy.”⁵⁸

Reshuffling of Funding for CCPI

According to DOE, \$140 million of the \$295 million previously allotted to the Southern Company Plant Barry project was redistributed to the Texas Clean Energy project and the Hydrogen Energy California project. DOE provided additional funding, resulting in each project receiving an additional \$100 million above its initial awards.⁵⁹ The remaining funding from the canceled Plant Barry project (up to \$154 million) was allotted to the NRG Energy project in Texas (see **Table 2**).⁶⁰

According to a DOE source, selection of the Basin Electric Power project was announced but a cooperative agreement was never awarded by DOE.⁶¹ Funds that were to be obligated for the Basin project could therefore have been reallocated within the department, but were rescinded by Congress in FY2011 appropriations.

Some of the funding for the AEP Mountaineer project was rescinded by Congress in FY2012 appropriations legislation (P.L. 112-74). In the report accompanying P.L. 112-74, Congress rescinded a total of \$187 million of prior-year balances from the Fossil Energy Research and Development account.⁶² The rescission did not apply to amounts previously appropriated under P.L. 111-5; however, funding for the AEP Mountaineer project that was provided by the Recovery Act and not spent was returned to the Treasury and not made available to the CCPI program.⁶³

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2011, http://www.nytimes.com/2011/07/14/business/energy-environment/utility-shelves-plan-to-capture-carbon-dioxide.html?_r=1.

⁵⁶ Michael G. Morris, chairman of AEP, quoted in Matthew L. Wald and John M. Broder, “Utility Shelves Ambitious Plan to Limit Carbon,” *The New York Times*, July 13, 2011.

⁵⁷ Wald and Broder, *New York Times*, July 13, 2011.

⁵⁸ MIT Carbon Capture & Sequestration Technologies, *AEP Mountaineer Fact Sheet: Carbon Dioxide Capture and Storage Project*, http://sequestration.mit.edu/tools/projects/aep_alstom_mountaineer.html.

⁵⁹ Telephone conversation with Joseph Giove, DOE Office of Fossil Energy, March 19, 2012.

⁶⁰ U.S. DOE Fossil Energy Techline, “Secretary Chu Announces Up To \$154 Million for NRG Energy’s Carbon Capture and Storage Project in Texas,” March 9, 2010, http://www.fossil.energy.gov/news/techlines/2010/10005-NRG_Energy_Selected_to_Receive_DOE.html.

⁶¹ Telephone conversation with Joseph Giove, DOE Office of Fossil Energy, April 11, 2011.

⁶² U.S. Congress, House Committee on Appropriations, Subcommittee on Military Construction, Veterans Affairs, and Related Agencies, *Military Construction and Veterans Affairs and Related Agencies Appropriations Act, 2012*, conference report to accompany H.R. 2055, 112th Cong., 1st sess., December 15, 2011, H.Rept. 112-331 (Washington: GPO, 2011), p. 851.

⁶³ Telephone conversation with Joseph Giove, DOE Office of Fossil Energy, March 19, 2012.

Industrial Carbon Capture and Storage Projects

The original DOE ICCS program was divided into two main areas: Area 1, consisting of large industrial demonstration projects; and Area 2, consisting of projects to test innovative concepts for the beneficial reuse of CO₂.⁶⁴ Under Area 1, the first phase of the program consisted of 12 projects cost-shared with private industry, intended to increase investment in clean industrial technologies and sequestration projects. Phase 1 projects averaged approximately seven months in duration. Following Phase 1, DOE selected three projects for Phase 2 for design, construction, and operation.⁶⁵ The three Phase 2 projects are listed as large-scale demonstration projects in **Table 3**. The total share of DOE funding for the three projects, provided by the Recovery Act, is \$686 million, or approximately 64% of the sum total Area 1 program cost of \$1.075 billion.

Under Area 2, the initial phase consisted of \$17.4 million in Recovery Act funding and \$7.7 million in private-sector funding for 12 projects to engage in feasibility studies to examine the beneficial reuse of CO₂.⁶⁶ In July 2010, DOE selected six projects from the original 12 projects for a second phase of funding to find ways of converting captured CO₂ into useful products such as fuel, plastics, cement, and fertilizer. The six projects are listed under “Innovative Concepts/Beneficial Use” in **Table 3**. The total share of DOE funding for the six projects, provided by the Recovery Act, is \$141.5 million, or approximately 71% of the sum total cost of \$198.2 million.

Since its original conception, the DOE ICCS program has expanded with an additional 22 projects, funded under the Recovery Act, to accelerate promising technologies for CCS.⁶⁷ In its listing of the 22 projects, DOE groups them into four general categories: (1) Large-Scale Testing of Advanced Gasification Technologies; (2) Advanced Turbo-Machinery to Lower Emissions from Industrial Sources; (3) Post-Combustion CO₂ Capture with Increased Efficiencies and Decreased Costs; and (4) Geologic Storage Site Characterization.⁶⁸ The total share of DOE funding for the 22 projects, provided by the Recovery Act, is \$594.9 million, or approximately 78% of the sum total cost of \$765.2 million.

Overall, the total share of federal funding for all the ICCS projects combined is \$1.422 billion, or approximately 70% of the sum total cost of \$2.038 billion.

⁶⁴ Email from Regis K. Conrad, Director, Division of Cross-Cutting Research, DOE, March 20, 2012.

⁶⁵ U.S. DOE, National Energy Technology Laboratory, *Major Demonstrations, Industrial Capture and Storage (ICCS): Area 1*, <http://www.netl.doe.gov/technologies/coalpower/cctc/iccs1/index.html#>.

⁶⁶ U.S. DOE, *Recovery Act, Innovative Concepts for Beneficial Reuse of Carbon Dioxide*, http://fossil.energy.gov/recovery/projects/beneficial_reuse.html.

⁶⁷ Email from Regis K. Conrad, Director, Division of Cross-Cutting Research, DOE, March 20, 2012.

⁶⁸ U.S. DOE, *Carbon Capture and Storage from Industrial Sources, Industrial Carbon Capture Project Selections*, http://fossil.energy.gov/recovery/projects/iccs_projects_0907101.pdf.

Table 3. DOE Industrial Carbon Capture and Storage (ICCS) Projects
(showing DOE share of funding and total project cost)

ICCS Project Name	Location	Type of Project	DOE Share of Funding (\$ millions)	Total Project Cost (\$ millions)	Percent DOE Share
Air Products & Chemicals, Inc.	Port Arthur, TX	Large-Scale Demonstration	284	431	66%
Archer Daniels Midland Co.	Decatur, IL	Large-Scale Demonstration	141	208	68%
Leucadia Energy, LLC	Lake Charles, LA	Large-Scale Demonstration	261	436	60%
Alcoa, Inc.	Alcoa Center, PA	Innovative Concepts/Beneficial Use	13.5	16.9	80%
Novomer, Inc.	Ithaca, NY	Innovative Concepts/Beneficial Use	20.5	25.6	80%
Touchstone Research Lab, Ltd.	Triadelphia, PA	Innovative Concepts/Beneficial Use	6.7	8.4	80%
Phycal, LLC	Highland Heights, OH	Innovative Concepts/Beneficial Use	51.4	65	80%
Skyonic Corp.	Austin, TX	Innovative Concepts/Beneficial Use	28	39.6	70%
Calera Corp.	Los Gatos, CA	Innovative Concepts/Beneficial Use	21.4	42.7	50%
Air Products & Chemicals, Inc.	Allentown, PA	Advanced Gasification Technologies	71.7	75	96%
Eltron Research & Development, Inc.	Boulder, CO	Advanced Gasification Technologies	71.4	73.7	97%
Research Triangle Institute	Research Triangle Park, NC	Advanced Gasification Technologies	168.8	174	97%
GE Energy	Schenectady, NY	Advanced Turbo-Machinery	31.3	62.6	50%
Siemens Energy	Orlando, FL	Advanced Turbo-Machinery	32.3	64.7	50%
Clean Energy Systems, Inc.	Rancho Cordova, CA	Advanced Turbo-Machinery	30	42.9	70%
Ramgen Power Systems	Bellevue, WA	Advanced Turbo-Machinery	50	79.7	63%
ADA-ES, Inc.	Littleton, CO	Post-Combustion Capture	15	18.8	80%
Alstom Power	Windsor, CT	Post-Combustion Capture	10	12.5	80%
Membrane Technology & Research, Inc.	Menlo Park, CA	Post-Combustion Capture	15	18.8	80%

ICCS Project Name	Location	Type of Project	DOE Share of Funding (\$ millions)	Total Project Cost (\$ millions)	Percent DOE Share
Praxair	Tonawanda, NY	Post-Combustion Capture	35	55.6	63%
Siemens Energy, Inc.	Pittsburgh, PA	Post-Combustion Capture	15	18.8	80%
Board of Trustees U. of IL	Champaign, IL	Geologic Site Characterization	5	6.5	77%
N. American Power Group, Ltd.	Greenwood Village, CO	Geologic Site Characterization	5	7.85	64%
Sandia Technologies, LLC	Houston, TX	Geologic Site Characterization	4.38	5.63	78%
S. Carolina Research Foundation	Columbia, SC	Geologic Site Characterization	5	6.25	80%
Terralog Technologies USA, Inc.	Arcadia, CA	Geologic Site Characterization	5	6.25	80%
U. of Alabama	Tuscaloosa, AL	Geologic Site Characterization	5	10.8	46%
U. of Kansas Center for Research, Inc.	Lawrence, KS	Geologic Site Characterization	5	6.29	80%
U. of Texas at Austin	Austin, TX	Geologic Site Characterization	5	6.25	80%
U. of Utah	Salt Lake City, UT	Geologic Site Characterization	5	7.23	69%
U. of Wyoming	Laramie, WY	Geologic Site Characterization	5	5	100%
Totals			1,422.4	2,038.4	70%

Source: Emails from Regis K. Conrad, Director, Division of Cross-Cutting Research, DOE, March 20 and March 27, 2012; U.S. DOE, National Energy Technology Laboratory, *Major Demonstrations, Industrial Capture and Storage (ICCS): Area 1*, <http://www.netl.doe.gov/technologies/coalpower/cctc/iccs1/index.html#>; U.S. DOE, *Carbon Capture and Storage from Industrial Sources, Industrial Carbon Capture Project Selections*, http://fossil.energy.gov/recovery/projects/iccs_projects_0907101.pdf.

Notes: Table is ordered from top to bottom by type of project: Large-Scale Demonstration; Innovative Concepts/Beneficial Use; Advanced Gasification Technologies; Advanced Turbo-Machinery; Post-Combustion Capture; and Geologic Site Characterization. Totals may not add due to rounding.

FutureGen—A Special Case?

On February 27, 2003, President George W. Bush proposed a 10-year, \$1 billion project to build a coal-fired power plant that would integrate carbon sequestration and hydrogen production at a 275 megawatt-capacity plant, enough to power about 150,000 average U.S. homes. As originally conceived, the plant would have been a coal-gasification facility and would have produced and sequestered between 1 million and 2 million tons of CO₂ annually. On January 30, 2008, DOE

announced that it was “restructuring” the FutureGen program away from a single, state-of-the-art “living laboratory” of integrated R&D technologies—a single plant—to instead pursue a new strategy of multiple commercial demonstration projects.⁶⁹ In the restructured program, DOE would support up to two or three demonstration projects of at least 300 megawatts that would sequester at least 1 million tons of CO₂ per year.

In the Bush Administration’s FY2009 budget, DOE requested \$156 million for the restructured FutureGen program, and specified that the federal cost-share would only cover the CCS portions of the demonstration projects, not the entire power system. However, after the Recovery Act was enacted on February 17, 2009, Secretary Chu announced an agreement with the FutureGen Alliance—an industry consortium—to advance construction of the FutureGen plant built in Mattoon, IL, the site selected by the FutureGen Alliance in 2007.⁷⁰ Further, DOE anticipated that \$1 billion of funding from the Recovery Act would be used to support the project.⁷¹

On August 5, 2010, then-Secretary of Energy Chu announced the \$1 billion award, from Recovery Act funds, to the FutureGen Alliance, Ameren Energy Resources, Babcock & Wilcox, and Air Liquide Process & Construction, Inc., to build FutureGen 2.0.⁷² FutureGen 2.0 differs from the original concept for the plant, because it would retrofit Ameren’s existing power plant in Meridosia, IL, with oxy-combustion technology at a 202 MW oil-fired unit,⁷³ rather than build a new state-of-the-art plant in Mattoon.⁷⁴

Challenges to FutureGen—A Similar Path for Other Demonstration Projects?

More than a decade after the George W. Bush Administration announced FutureGen—its signature clean coal power initiative—the program is still in early development. Among the challenges to the development of FutureGen 2.0 are rising costs of production, ongoing issues with project development, lack of incentives for investment from the private sector, time constraints, and competition with foreign nations. Remaining challenges to FutureGen’s development include securing private sector funding to meet increasing costs, purchasing the power plant for the project, obtaining permission from DOE to retrofit the plant, performing the retrofit, and then meeting the goal of 90% capture of CO₂.⁷⁵

A question for Congress is whether FutureGen represents a unique case of a first mover in a complex, expensive, and technically challenging endeavor, or whether it represents all large CCS

⁶⁹ See http://www.fossil.energy.gov/news/techlines/2008/08003-DOE_Announces_Restructured_FutureG.html.

⁷⁰ Prior to when DOE first announced it would restructure the program in 2008, the FutureGen Alliance announced on December 18, 2007, that it had selected Mattoon, IL, as the host site from a set of four finalists. The four were Mattoon, IL; Tuscola, IL; Heart of Brazos (near Jewett, TX); and Odessa, TX.

⁷¹ See DOE announcement on June 12, 2009, http://www.fossil.energy.gov/news/techlines/2009/09037-DOE_Announces_FutureGen_Agreement.html.

⁷² See DOE Techline, http://www.netl.doe.gov/publications/press/2010/10033-Secretary_Chu_Announces_FutureGen_.html.

⁷³ Ameren had planned to replace the oil-fired boiler with a coal-fired boiler using oxy-combustion technology to allow carbon capture. See <http://www.futuregenalliance.org/pdf/FutureGen%20FAQ-General%20042711.pdf>.

⁷⁴ For more information about the history of FutureGen, and issues for Congress, see CRS Report R43028, *The FutureGen Carbon Capture and Sequestration Project: A Brief History and Issues for Congress*, by Peter Folger

⁷⁵ For more information on FutureGen, see CRS Report R43028, *The FutureGen Carbon Capture and Sequestration Project: A Brief History and Issues for Congress*, by Peter Folger

demonstration projects once they move past the planning stage. As discussed above, approximately \$3.3 billion of Recovery Act funding is committed to large demonstration projects, including FutureGen. A rationale for committing such a substantial level of funding to demonstration projects was to scale up CCS RD&D more quickly than had been the pace of technology development prior to enactment of the Recovery Act. However, if all the CCS demonstration projects encounter similar changes in scope, design, location, and cost as FutureGen, the goals laid out in the DOE 2011 *Strategic Plan*—namely, to bring at least five commercial-scale CCS demonstration projects online by 2016—may be in jeopardy.

Alternatively, one could argue that FutureGen from its original conception was unique. None of the other large-scale demonstration projects share the same original ambitious vision: to create a new, one-of-a-kind, near-zero emission CCS plant from the ground up. Even though the individual components of FutureGen—as originally conceived—were not themselves new innovations, combining the capture, transportation, and storage components together into a 250-megawatt functioning power plant could be considered unprecedented and therefore most likely to experience delays at each step in development.

Scholars have described the stages of technological change in different schemes, such as

- invention, innovation, adoption, diffusion;⁷⁶ or
- technology readiness levels (TRLs) ranging from TRL 1 (basic technology research) to TRL 9 (system test, launch, and operations);⁷⁷ or
- conceptual design, laboratory/bench scale, pilot plant scale, full-scale demonstration plant, and commercial process.⁷⁸

FutureGen is difficult to categorize within these schemes, in part because the project spanned a range of technology development levels irrespective of the particular scheme. The original conception of the FutureGen project arguably had aspects of conceptual design through commercial processes—all five components of the scheme listed as the third bullet above—which meant that the project was intended to march through all stages in a linear fashion. As some scholars have noted, however, the stages of technological change are highly interactive, requiring learning by doing and learning by using, once the project progresses past its innovative stage into larger-scale demonstration and deployment.⁷⁹ The task of tackling all the stages of technology development in one project—the original FutureGen—might have been too daunting and, in addition to other factors, contributed to the project’s erratic progress since 2003. It remains to be seen whether the current large-scale demonstration projects funded by DOE under CCPI Round 3 follow the path of FutureGen or instead achieve their technological development goals on time and within their current budgets. Presumably, lessons learned during the planning, construction,

⁷⁶ E. S. Rubin, “The Government Role in Technology Innovation: Lessons for the Climate Change Policy Agenda,” Institute of Transportation Studies, 10th Biennial Conference on Transportation Energy and Environmental Policy, University of California, Davis, CA (August 2005).

⁷⁷ National Aeronautics and Space Administration, “Definition of Technology Readiness Levels,” at http://esto.nasa.gov/files/TRL_definitions.pdf.

⁷⁸ For a more thorough discussion of different schemes describing stages of technology development, see chapter 4 of CRS Report R41325, *Carbon Capture: A Technology Assessment*, by Peter Folger.

⁷⁹ E. S. Rubin, “The Government Role in Technology Innovation: Lessons for the Climate Change Policy Agenda,” Institute of Transportation Studies, 10th Biennial Conference on Transportation Energy and Environmental Policy, University of California, Davis, CA (August 2005).

and operation of these demonstration projects will be shared with the broader electric power industry.⁸⁰

Geologic Sequestration/Storage: DOE RD&D for the Last Step in CCS

DOE has allocated \$112 million in FY2012, \$110 million in FY2013, and \$109 million in FY2014 for its carbon sequestration/storage activities. (See **Table 1**.) In contrast with the carbon capture technology RD&D, which received nearly all of the \$3.4 billion from Recovery Act funding, carbon sequestration/carbon storage activities received approximately \$50 million in Recovery Act funds. Recovery Act funds were awarded for 10 projects to conduct site characterization of promising geologic formations for CO₂ storage.⁸¹

Brief History of DOE Geological Sequestration/Storage Activities

DOE has devoted the bulk of its funding for geological sequestration/storage activities to RD&D efforts for injecting CO₂ into subsurface geological reservoirs. Injection and storage is the third step in the CCS process following the CO₂ capture step and CO₂ transport step. One part of the RD&D effort is characterizing geologic reservoirs (which received a \$50 million boost from Recovery Act funds, as noted above); however, the overall program is much broader than just characterization, and has now reached the beginning of the phase of large-volume CO₂ injection demonstration projects across the country. According to DOE, these large-volume tests are needed to validate long-term storage in a variety of different storage formations of different depositional environments, including deep saline reservoirs, depleted oil and gas reservoirs, low permeability reservoirs, coal seams, shale, and basalt.⁸² The large-volume tests can be considered injection experiments conducted at a commercial scale (i.e., approximately 1 million tons of CO₂ injected per year) that should provide crucial information on the suitability of different geologic reservoirs; monitoring, verification, and accounting of injected CO₂; risk assessment protocols for long-term injection and storage; and other critical challenges.

In 2003 DOE created seven regional carbon sequestration partnerships (RCSPs), essentially consortia of public and private sector organizations grouped by geographic region across the United States and parts of Canada.⁸³ The geographic representation was intended to match regional differences in fossil fuel use and geologic reservoir potential for CO₂ storage.⁸⁴ The

⁸⁰ Another possible source of uncertainty for FutureGen, and other large industrial CCS projects, is cost recovery during the operating phase of the plant after the construction phase and initial capital investments are made. “Learning by doing” should increase operating efficiency, but it is unclear by how much and over what time span. For more discussion on cost trajectories and expected efficiency gains, see CRS Report R41325, *Carbon Capture: A Technology Assessment*, by Peter Folger.

⁸¹ The total DOE share for the 10 projects is \$46.6 million. See DOE, *Recovery Act*, http://fossil.energy.gov/recovery/projects/site_characterization.html.

⁸² DOE 2010 *CCS Roadmap*, p. 55.

⁸³ Four Canadian provinces are partners with DOE in two of the regional partnerships, and are members with other participating organizations that are contributing funding and other support to the partnerships.

⁸⁴ DOE National Energy Technology Laboratory, Carbon Sequestration Regional Carbon Sequestration Partnerships, http://www.netl.doe.gov/technologies/carbon_seq/infrastructure/rcsp.html.

RCSPs cover 43 states and 4 Canadian provinces and include over 400 organizations, according to the DOE 2011 *Strategic Plan*. **Table 4** shows the seven partnerships, the lead organization for each, and the states and provinces included. Several states belong to more than one RCSP.

Table 4. Regional Carbon Sequestration Partnerships

Regional Carbon Sequestration Partnership (RCSP)	Lead Organization	States and Provinces in the Partnership
Big Sky Carbon Sequestration Partnership (BSCSP)	Montana State University-Bozeman	MT, WY, ID, SD, eastern WA, eastern OR
Midwest Geological Sequestration Consortium (MGSC)	Illinois State Geological Survey	IL, IN, KY
Midwest Regional Carbon Sequestration Partnership (MRCSP)	Battelle Memorial Institute	IN, KY, MD, MI, NJ, NY, OH, PA, WV,
Plains CO ₂ Reduction Partnership (PCOR)	University of North Dakota Energy and Environmental Research Center	MT, northeast WY, ND, SD, NE, MN, IA, MO, WI, Manitoba, Alberta, Saskatchewan, British Columbia (Canada)
Southeast Regional Carbon Sequestration Partnership (SECARB)	Southern States Energy Board	AL, AS, FL, GA, LA, MS, NC, SC, TN, TX, VA, portions of KY and WV
Southwest Regional Partnership on Carbon Sequestration (SWP)	New Mexico Institute of Mining and Technology	AZ, CO, OK, NM, UT, KS, NV, TX, WY
West Coast Regional Carbon Sequestration Partnership (WESTCARB)	California Energy Commission	AK, AZ, CA, HI, OR, NV, WA, British Columbia (Canada)

Source: DOE National Energy Technology Laboratory, *Carbon Sequestration Regional Carbon Sequestration Partnerships*, http://www.netl.doe.gov/technologies/carbon_seq/infrastructure/rcsp.html.

The RCSPs have pursued their objectives through three phases beginning in 2003: (1) Characterization Phase (2003 to 2005), an initial examination of the region's potential for geological sequestration of CO₂; (2) Validation Phase (2005 to 2011), small-scale injection field tests (less than 500,000 tons of CO₂) to develop a better understanding of how different geologic formations would handle large amounts of injected CO₂; and (3) Development Phase (2008 to 2018 and beyond), injection tests of at least 1 million tons of CO₂ to simulate commercial-scale quantities of injected CO₂.⁸⁵ The last phase is intended also to collect enough information to help understand the regulatory, economic, liability, ownership, and public outreach requirements for commercial deployment of CCS.

There are RD&D activities funded by DOE under its carbon sequestration/carbon storage program activities other than the RCSPs, such as geological storage technologies; monitoring, verification, and assessment; carbon use and reuse; and others. However, the RCSPs were allocated approximately 70% of annual spending on carbon sequestration/carbon storage in FY2012, and comprised 66% of that account in the FY2014 budget request. The RCSPs provide

⁸⁵ Ibid.

the framework and infrastructure for a wide variety of DOE geologic sequestration/storage activities.

Current Status and Challenges to Carbon Sequestration/Storage

The third phase—Development—is currently underway for all the RCSPs, and large-scale CO₂ injection has begun for the SECARB and MGSC projects.⁸⁶ The Development Phase large-scale injection projects are arguably akin to the large-scale carbon capture demonstration projects discussed above (See **Table 2**). They are needed to understand what actually happens to CO₂ underground when commercial-scale volumes are injected in the same or similar geologic reservoirs as would be used if CCS were deployed nationally.

In addition to understanding the technical challenges to storing CO₂ underground without leakage over hundreds of years, DOE also expects that the Development Phase projects will provide a better understanding of regulatory, liability, and ownership issues associated with commercial-scale CCS.⁸⁷ These nontechnical issues are not trivial, and could pose serious challenges to widespread deployment of CCS even if the technical challenges of injecting CO₂ safely and in perpetuity are resolved. For example, a complete regulatory framework for managing the underground injection of CO₂ has not been developed in the United States. However, EPA promulgated a rule under the authority of the Safe Drinking Water Act (SDWA) that creates a new class of injection wells under the existing Underground Injection Control Program. The new class of wells (Class VI) establishes national requirements specifically for injecting CO₂ and protecting underground sources of drinking water. EPA's stated purpose in proposing the rule was to ensure that CCS can occur in a safe and effective manner in order to enable commercial-scale CCS to move forward.⁸⁸

The development of the regulation for Class VI wells highlighted that EPA's authority under the SDWA is limited to protecting underground sources of drinking water but does not address other major issues. Some of these include the long-term liability for injected CO₂, regulation of potential emissions to the atmosphere, legal issues if the CO₂ plume migrates underground across state boundaries, private property rights of owners of the surface lands above the injected CO₂ plume, and ownership of the subsurface reservoirs (also referred to as pore space).⁸⁹ Because of these issues and others, there are some indications that broad community acceptance of CCS may be a challenge. The large-scale injection tests may help identify the key factors that lead to community concerns over CCS, and help guide DOE, EPA, other agencies, and the private sector towards strategies leading to the widespread deployment of CCS. Currently, however, the general public is largely unfamiliar with the details of CCS and these challenges have yet to be resolved.⁹⁰

⁸⁶ For details on the two large-scale injection experiments by SECARB, see <http://www.secarbon.org/>; for details on the large-scale injection experiment by MGSC, see <http://sequestration.org/>.

⁸⁷ DOE National Energy Technology Laboratory, *Carbon Sequestration Regional Partnership Development Phase (Phase III) Projects*, http://www.netl.doe.gov/technologies/carbon_seq/infrastructure/rcspiii.html.

⁸⁸ For more information on the EPA Class VI wells in particular, and the Safe Drinking Water Act generally, see CRS Report RL34201, *Safe Drinking Water Act (SDWA): Selected Regulatory and Legislative Issues*, by Mary Tiemann.

⁸⁹ For a discussion of several of these legal issues, see CRS Report RL34307, *Legal Issues Associated with the Development of Carbon Dioxide Sequestration Technology*, by Adam Vann and Paul W. Parfomak.

⁹⁰ For more information on the different issues regarding community acceptance of CCS, see CRS Report RL34601, *Community Acceptance of Carbon Capture and Sequestration Infrastructure: Siting Challenges*, by Paul W. Parfomak.

Outlook

Testimony from Scott Klara of the National Energy Technology Laboratory sums up a crucial metric for the success of the federal CCS RD&D program, namely, whether CCS technologies are deployed in the commercial marketplace:

The success of the Clean Coal Program will ultimately be judged by the extent to which emerging technologies get deployed in domestic and international marketplaces. Both technical and financial challenges associated with the deployment of new “high risk” coal technologies must be overcome in order to be capable of achieving success in the marketplace. Commercial scale demonstrations help the industry understand and overcome startup issues, address component integration issues, and gain the early learning commercial experience necessary to reduce risk and secure private financing and investment for future plants.⁹¹

To date, there are no commercial ventures in the United States that capture, transport, and inject large quantities of CO₂ (e.g., 1 million tons per year or more) solely for the purposes of carbon sequestration.

However, the CCS RD&D program has embarked on commercial-scale demonstration projects for CO₂ capture, injection, and storage. The success of these demonstration projects will likely bear heavily on the future outlook for widespread deployment of CCS technologies as a strategy for preventing large quantities of CO₂ from reaching the atmosphere while plants continue to burn fossil fuels, mainly coal. The September 20, 2013, re-proposal of an EPA standard to limit CO₂ emissions from coal-fired power plants has invited renewed scrutiny of CCS technology and its prospects for commercial deployment. Congress may wish to carefully review the results from these demonstration projects as they progress in order to gauge whether DOE is on track to meet its goal of allowing for an advanced CCS technology portfolio to be ready by 2020 for large-scale demonstration and deployment in the United States.

In addition to the issues and programs discussed above, other factors might affect the demonstration and deployment of CCS in the United States. The use of hydraulic fracturing techniques to extract unconventional natural gas deposits recently has drawn national attention to the possible negative consequences of deep well injection of large volumes of fluids. Hydraulic fracturing involves the high-pressure injection of fluids into the target formation to fracture the rock and release natural gas or oil. The injected fluids, together with naturally occurring fluids in the shale, are referred to as produced water. Produced waters are pumped out of the well and disposed of. Often the produced waters are disposed of by re-injecting them at a different site in a different well. These practices have raised concerns about possible leakage as fluids are pumped into and out of the ground, and about deep-well injection causing earthquakes. Public concerns over hydraulic fracturing and deep-well injection of produced waters may spill over into concerns about deep-well injection of CO₂. How successfully DOE is able to address these types of concerns as the large-scale demonstration projects move forward into their injection phases could affect the future of CCS deployment.

⁹¹ Testimony of Scott Klara, Deputy Laboratory Director, National Energy Technology Laboratory, U.S. Department of Energy, in U.S. Congress, Senate Energy and Natural Resources Committee, *Carbon Capture and Sequestration Legislation*, hearing to receive testimony on carbon capture and sequestration legislation, including S. 699 and S. 757, 112th Cong., 1st sess., May 12, 2011, S.Hrg. 112-22.

Author Contact Information

Peter Folger
Specialist in Energy and Natural Resources Policy
pfolger@crs.loc.gov, 7-1517