

State and Regional Control of Geological Carbon Sequestration

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Abstract

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. Carbon capture and geologic sequestration offer one method to reduce carbon emissions from coal and other hydrocarbon energy production. While the federal government is providing increased funding for carbon capture and sequestration, recent congressional legislative efforts to create a framework for regulating carbon emissions have failed. However, regional and state bodies have taken significant actions both to regulate carbon and facilitate its capture and sequestration. This article explores how regional bodies and state government are addressing the technical and legal problems that must be resolved in order to have a viable carbon sequestration program. Several regional bodies have formed regulations and model laws that affect carbon capture and storage, and three bodies comprising twenty-three states—the Regional Greenhouse Gas Initiative, the Midwest Regional Greenhouse Gas Reduction Accord, and the Western Climate Initiative—have cap-and-trade programs in various stages of development. State property, land use and environmental laws affect the development and implementation of carbon capture and sequestration projects, and unless federal standards are imposed, state laws on torts and renewable portfolio requirements will directly affect the liability and viability of these projects. This paper examines current state laws and legislative efforts addressing carbon capture and sequestration.

Executive Summary

In the absence of comprehensive federal legislation regulating carbon dioxide, regional and state actions are becoming increasingly important voices in the policy discussion of how best to implement effective control of carbon dioxide emissions (CO₂). Regional bodies and state governments are responding to concerns about climate change and energy sustainability by enacting laws, regulations, and economic incentives to promote differing energy strategies that will impact carbon capture and sequestration efforts. This paper looks at the approaches to CO₂ regulation—including its capture, transportation, and storage (geological sequestration)—of several regional bodies and eighteen western states.

The Interstate Oil and Gas Compact Commission (IOGCC) is a regional body that represents the oil and gas interests of its thirty-eight member states and nine international affiliates. It has produced a comprehensive model legal and regulatory framework for geologic storage of CO₂ that advocates state and provincial level regulation of stored CO₂. Other efforts to control GHG regulation and influence federal policy led twenty-three eastern, mid-western and western states to participate in three different regional approaches to GHG control. Although each group emphasizes different goals and uses different paths to regulate and enforce its policies, these regional bodies provide varying levels of cooperation, investment, and direction for addressing climate change issues and carbon capture and storage. Since 2005, cap-and-trade programs have been the main approach favored by these regional programs. The Regional Greenhouse Gas Initiative is the oldest of the three and has held auctions of CO₂ allowances for electric power generators since 2005. The Midwest Regional Greenhouse Gas Reduction Accord takes a very favorable view of carbon capture and storage and has finalized recommendations for a cap-and-trade program, but the member states have yet to ratify the recommendations. The Western Climate Initiative also has developed model rules and supporting regulations. Two member states, California and New Mexico, have passed legislation to begin the cap-and-trade program in 2012, but New Mexico's program may not continue because of the opposition by a new governor. There is speculation that because federal legislation has stalled the three regional programs will link together to pressure and incentivize other states to adopt climate change strategies. But the political changes that limit federal action may also limit state efforts. Collaboration between the three regional programs, however, has been limited so far to a white paper on offsets that provides common definitions and review processes.

Individual states are also enacting legislation and regulatory processes for carbon capture and sequestration. The review of western states' initiatives shows that even states with such different stances on climate change and government regulation as California and Texas have indicated governmental support for carbon capture and sequestration and enacted extensive and often similar legislation to regulate it. Funding has increased dramatically over the past decade, and although carbon sequestration still faces substantial technological and financial hurdles

although some of the political and legal hurdles are being addressed in several states.

The adoption of a cap-and-trade program for greenhouse gases by either states or regional bodies will make carbon emissions a significant cost item for electricity generators. This will make carbon capture and sequestration more attractive and economically practical for sources under the program. While the fate of national and global actions to combat climate change are uncertain, much time, money, and planning has been invested by several states and regional bodies to define, regulate, and promote carbon capture and sequestration. There have been great advances in the technology, implementation, and legal and policy foundations for carbon capture and storage in the United States over the past several years, but whether this technology becomes broadly accepted will depend on whether its costs can be reduced and how energy policy evolves in the United States.

List of Acronyms

2009 IEPR	2009 Integrated Energy Policy Report
AB	Assembly Bill (California)
AB 1925	California Assembly Bill 1925, An Act Relating to Energy
AB 32	California Global Warming Solutions Act of 2006
ADEQ	Arizona Department of Environmental Quality
AoR	Area of Review
ARRA	American Recovery and Reinvestment Act
BACT	Best Available Control Technology
CAA	Clean Air Act
CARB	California Air Resources Board
CBM	Coalbed Methane
CCGS Workgroup	Utah Carbon Capture and Geologic Sequestration Working Group
CCS	Carbon Capture and Sequestration
CCS Panel	California Carbon Capture and Storage Review Panel
CGS	California Geological Survey
CO ₂	Carbon Dioxide
CO _{2e}	Carbon Dioxide Equivalent
CPUC	California Public Utilities Commission
CSAD	Cap Setting and Allowance Distribution
DOE	Department of Energy
DOGGR	California Division of Oil, Gas and Geothermal Resources
DOI	Department of the Interior
DOT	Department of Transportation
EITE	Energy-Intensive, Trade-Exposed
EJAC	Environmental Justice Advisory Committee
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
ETAAC	Economic and Technology Advancement Advisory Committee
FERC	Federal Energy Regulatory Commission
FJD	First Jurisdictional Deliverer
FWPCA	Federal Water Pollution Control Act
GHG	Greenhouse Gas
Gt	Gigaton
HFC	Hydrofluorocarbon
IDEQ	Idaho Department of Environmental Quality
IEPR	California Integrated Energy Policy Report
IGCC	Integrated Gasification Combined Cycle
IOGCC	Interstate Oil and Gas Compact Commission
IPCC	Intergovernmental Panel on Climate Change
KWh	Kilowatt Hour
LCFS	Low Carbon Fuel Standards
MGA	Midwestern Governors Association
MGGA	Midwest Regional Greenhouse Gas Reduction Accord
MMV	Monitoring, Measurement and Verification

MTBE	Methyl Tertiary Butyl Ether
MW	Megawatt
MWh	Megawatt hour
NIMBY	Not In My Backyard
NO _x	Nitrogen oxide
PAA	Price Anderson Act
PFC	Perfluorocarbon
PGE	Portland General Electric Company
PHMSA	Pipeline and Hazardous Materials Safety Administration
PISC	Post-injection Site Care
REC	Renewable Energy Credit
RGGI	Regional Greenhouse Gas Initiative
RoD	Rate of Decline
RPS	Renewable Portfolio Standards
SDWA	Safe Drinking Water Act
SF ₆	Sulfur Hexafluoride
SO ₂	Sulfur Dioxide
STB	Surface Transportation Board
SWP	Department of Energy Southwest Partnership on Carbon Sequestration
TCEP	Texas Clean Energy Project
tCO _{2e}	Ton of Carbon Dioxide Equivalent
TNRC	Texas Natural Resource Conservation Commission
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USGS	U.S. Geological Survey
WCI	Western Climate Initiative
WESTCARB	West Coast Regional Carbon Sequestration Partnership

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§ 1. Carbon Sequestration

Carbon sequestration may be accomplished through either storage in a geologic depository or by using a biologic process in which carbon dioxide is removed from the atmosphere by plants that store carbon.¹ Biological sequestration is a well-established and cost effective way to sequester carbon, but it is difficult to quantify the benefits. Geologic sequestration involves the separation of carbon dioxide (CO₂) from an exhaust gas stream and compressing it, transporting it to a suitable site, and injecting it into a deep underground formation. It will be some time in the future before sequestration in geologic formations is proven to be an effective and economical way to reduce CO₂ emissions to the atmosphere, but a major benefit from developing effective geologic sequestration is that America's abundant supply of coal could be utilized without the adverse environmental impacts associated with CO₂ emissions. However there are risks from geologic sequestration that have been identified, including changes in soil chemistry that could harm the ecosystem, effects on water quality due to acidification, effects of geologic stability, and the potential for large releases that could harm or suffocate people and animals.²

After a brief discussion of the main components of CO₂ sequestration (CO₂ capture, transportation, storage, and long-term liability), this paper explores major legal and policy actions taken by regional and state bodies that will impact CO₂ sequestration. Federal control of geologic sequestration has been covered in a prior publication.³

§ 1(a). Carbon Capture

Carbon capture and storage (CCS) begins by separating CO₂ from other gases, which may be done before or after fuel is combusted.⁴ Post-combustion capture involves concentrating the exhaust gases into a stream of nearly pure carbon dioxide, and then compressing it to convert it from gas to a supercritical fluid before it is transported to the injection site by pipeline. CO₂ may be captured and sequestered from fossil-fueled power plants or from industrial processes including

¹ It may also be possible to inject CO₂ into soil, a process known as soil carbon sequestration, to help reduce atmospheric CO₂ concentrations. See Tripp Baltz, *USDA Research Service Begins Study Of Carbon Storage in Soil in Wyoming*, 40 Env't Rep. (BNA) 1709 (July 17, 2009).

² *International Climate Study Examines Feasibility of CO₂ Storage*, XVI CLEAN AIR REPORT (Inside EPA) 4:4 (Feb. 24, 2005). See also IPCC SPECIAL REPORT: CARBON DIOXIDE CAPTURE AND STORAGE (Bert Metz *et al.* eds., 2005), available at http://www.ipcc.ch/pdf/special-reports/srccs/srccs_summaryforpolicymakers.pdf (last visited Dec. 30, 2010) [hereinafter IPCC SPECIAL REP.].

³ Arnold W. Reitze, Jr., *Federal Control of Geological Carbon Sequestration*, PACE ENVTL. L. REV. (forthcoming 2011).

⁴ UNITED STATES GOVERNMENT ACCOUNTABILITY OFFICE, *FEDERAL ACTIONS WILL GREATLY AFFECT THE VIABILITY OF CARBON CAPTURE AND STORAGE AS A KEY MITIGATION OPTION* 10 (Sept. 2008) [GAO-08-1080] [hereinafter GAO].

the production of hydrogen and other chemicals, the production of substitute natural gas, and the production of transportation fuel.

The majority of the costs of sequestration result from separating and capturing CO₂ from flue gas.⁵ Carbon capture from the flue gas of coal-burning power plants will be more expensive than the carbon capture used by industrial processes that involve more concentrated streams of CO₂. The low concentration of CO₂ in conventional post-combustion gas streams means that large volumes of flue gas must be processed to remove CO₂. Conventional power plant CO₂ emissions are about 13% to 15% by volume, which increases energy requirements needed to remove a given quantity of CO₂ from the gas stream compared to gas streams with higher concentrations of CO₂.⁶ If the nitrogen in air is removed prior to combustion, such as occurs in the oxyfuel process, the CO₂ in the exhaust stream is concentrated, and it is less costly to separate a given amount of the gas.⁷ Integrated Gasification Combined Cycle (IGCC) plants also have lower CO₂ separation costs than conventional power plants because the CO₂ concentration is higher, therefore less energy is required to remove a ton of CO₂.⁸ An Intergovernmental Panel on Climate Change (IPCC) report estimates the cost of carbon capture at 1.8 to 3.4 cents/kilowatt hour (KWh) for a pulverized coal plant; 0.9 to 2.2 cents/KWh for a coal-burning IGCC plant; and 1.2 to 2.4 cents/KWh for a natural gas combined-cycle power plant.⁹

After the CO₂ is removed from the exhaust gas stream at either a conventional or an IGCC facility, it must be compressed to liquefy it for transport.¹⁰ This reduces the efficiency of the electric generation process because of the energy required to liquefy CO₂. It is estimated that carbon capture from a new IGCC plant would increase the cost of electricity production by less than half the cost of carbon capture from a new pulverized coal plant, in part because it produces a higher concentration CO₂ stream, which lowers energy requirements for liquefying the CO₂.¹¹ But it is pulverized coal plants that generate 99% of the electricity produced from burning coal.¹² Carbon capture from most conventional power plants that use pulverized coal would require post-combustion capture using technologies such as chilled ammonia, which could increase the cost of electricity by 59% according to a 2007 Department of Energy (DOE) report.¹³

⁵ See NETL, Technologies: Carbon Sequestration, http://www.netl.doe.gov/technologies/carbon_seq/ (last visited Dec. 30, 2010).

⁶ GAO, *supra* note 4, at 18.

⁷ Oxyfuel, The Institute for Clean and Secure Energy, The University of Utah (2009).

⁸ *Id.*

⁹ IPCC SPECIAL REPORT ON CARBON DIOXIDE CAPTURE AND STORAGE 341, *supra* note 2.

¹⁰ *Id.* at 22.

¹¹ *Id.* at 18.

¹² NETL, Carbon Sequestration: CO₂ Capture,

http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html (last visited Dec. 30, 2010).

¹³ *Industry Downplays DOE Report Doubting CO₂ Capture Process*, XVIII CLEAN AIR REP. (Inside EPA) 15:4 (July 26, 2007).

CCS will dramatically increase the cost of energy. In 2009 DOE stated 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 advanced gasification-based plant by about 35%.¹⁴ Overall CO₂ sequestration costs are estimated at \$25 to \$90 a metric ton, depending on the source.¹⁵ DOE estimates that sequestration from an IGCC facility will increase the average cost of electricity from 7.8 cents per KWh to 10.2 cents per KWh.¹⁶ A report prepared at the University of Utah found the cost of carbon capture to be about \$40 per ton and underground storage costs about \$10 per ton, which would add 7.5 cents to the cost of a KWh.¹⁷ This cost would be added to the average delivered cost of 8.9 cents per KWh.¹⁸ The American Coalition for Clean Coal Electricity, a coal-fired electric industry group, estimates the cost of having carbon sequestration available by 2025 at \$17 billion.¹⁹ The added cost is projected by an MIT study to nearly double the cost of a kilowatt-hour of electricity.²⁰ These increases to the cost of electricity may encourage the use of various funding mechanisms that hide the costs. These could include investment tax credits, carbon sequestration credits, subsidies based on a cap-and-trade program, federal loan guarantees, and federal financing.²¹

A report by the IPCC estimated that CCS would increase the cost of a KWh of electricity from a natural gas combined cycle plant by one to four cents. CCS for CO₂ from a pulverized coal plant would increase costs by two to four cents, and the cost increase for an IGCC plant would be one to three cents a KWh. Thus, CCS, according to the IPCC, would increase the cost of producing electricity by about 30% to 60%. These estimates are considerably lower than the DOE estimates. The IGCC study also says that since none of these technologies have used CCS at a full-scale facility, the costs of these systems cannot be stated with a high degree of confidence.²² 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. A

¹⁴ U.S. DEPT. OF ENERGY, CARBON CAPTURE AND STORAGE R & D OVERVIEW, *available at* <http://www.fossil.energy.gov/programs/sequestration/overview.html> (last visited Dec. 30, 2010).

¹⁵ IPCC SPECIAL REP., *supra* note 2.

¹⁶ NETL, *supra* note 12.

¹⁷ Stephen Sicilliano, *Sequestration Called Best Way to Achieve Short-Term Reductions of Carbon Emissions*, 38 Env't Rep. (BNA) 2286 (Oct. 26, 2007).

¹⁸ GAO, *supra* note 4, at 23.

¹⁹ Michael Kinsley, *U.S. Shouldn't Give Up on Clean Coal*, SALT LAKE TRIBUNE, Mar. 21, 2009, at A13.

²⁰ Mass. Inst. of Tech., THE FUTURE OF COAL, SUMMARY REPORT 19 (2007), *available at* http://web.mit.edu/coal/The_Future_of_Coal.pdf (Massachusetts Institute of Technology 2007) (last visited Dec. 30, 2010).

²¹ Steven D. Cook, *Dorgan Report Sees Minimum of \$110 Billion Needed to Deploy Carbon Capture, Storage*, 40 Env't Rep. (BNA) 2762 (Dec. 4, 2009).

²² IPCC SPECIAL REPORT, *supra* note 2, at 10.

California Public Utilities Commission report of June 12, 2009, estimates electric power will cost 16.7% more in 2020, even without a sequestration requirement.²³

§ 1(b). Carbon Dioxide Transport

After CO₂ is captured it must be transported to a storage site for underground injection. Even with relatively convenient access to storage reservoirs, transportation will be costly because a 1,000 megawatt (MW) plant will consume about 13,000 tons of coal each day.²⁴ The weight of CO₂ 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 on the moisture content and carbon content of the fuel.²⁵ Thus, a 1,000 MW power plant using 13,000 tons a day of Powder River Basin coal would produce about 26,824 tons of CO₂ per day.²⁶ CO₂ in the super critical state used for injection has a density of 0.03454 cubic feet per pound or about 69 cubic feet per ton.²⁷ Thus, a modern power plant could be expected to need to transport liquid CO₂ in an amount of over 1.85 million cubic feet each day, which is equivalent to the volume of a football field over 32.13 feet deep.²⁸ Electrical generation in 2008 in the United States produced 2,363.5 million metric tons of CO₂.²⁹ This would result in the generation of 163,081 million cubic feet of super critical CO₂ a year, which is a column one square mile at its base and over 1.11 miles high.³⁰

²³ Carolyn Whetzel, *Report Says State's Plan to Boost Renewable Portfolio Ambitious, Costly*, 40 Env't Rep. (BNA) 1463 (June 19, 2009).

²⁴ See Power 4 Georgians, <http://power4georgians.com/wcpp.aspx> (last visited Dec. 30, 2010).

²⁵ 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 carbon dioxide that weighs 3.664 times the weight of the carbon based on the atomic weights of oxygen and carbon. BABCOCK & WILCOX, STEAM ITS GENERATION AND USE 2-4, 2-8, tbl.10 (37th ed. 1960); B.D. Hong & E.R. Slatick, *Carbon Dioxide Emission Factors for Coal*, DOE, Energy Information Administration, available at http://www.eia.doe.gov/cneaf/coal/quarterly/co2_article/co2.html (last visited Dec. 30, 2010).

²⁶ For 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 CO₂ will produce 26,824 tons per day of carbon dioxide (13,000 x .76 x .741 x 3.664). Calculated from data found in BABCOCK & WILCOX, *supra* note 25, at 2-8, 2-9.

²⁷ CHEMICAL ENGINEER HANDBOOK, 5th ed. 3-162 (Robert H. Perry ed. 1953). The IPCC Special Rep., *supra* note 2, 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.

²⁸ An NFL football field is 360 by 160 feet, which is 57,600 square feet. See <http://www.sportsknowhow.com> (last visited Dec. 30, 2010). A power plant's production of 26,824 tons per day of carbon dioxide at 69 cubic feet per ton results in 1.85 million cubic feet of super critical carbon dioxide. Divided by 57,600. This gives a depth of 32.13 feet.

²⁹ U.S. Envtl. Protection Agency, *2010 Inventory of Greenhouse Gas Emissions and Sinks*, at 3-1, available at http://www.epa.gov/climatechange/emissions/downloads10/US-GHG-Inventory-2010_Chapter3-Energy.pdf (last visited Dec. 28, 2010).

³⁰ 5,280 x 5,280 = 27.88 million sq. ft. 163,081 million/ 27.88 million = 5,849.4 ft or 1.11 miles.

In addition to the significant engineering and economic issues concerning transporting CO₂, carbon sequestration raises legal issues concerning CO₂ transport and the potential liability for transportation mishaps. CO₂ is compressed into a supercritical fluid for transport, usually via a pipeline, to a site where it can be injected far below the ground. Safety regulations for these pipelines will be within the jurisdiction of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) for pipelines that affect interstate commerce. PHMSA also provides minimum standards for states that regulate intrastate pipelines.

Before large-scale CO₂ transport occurs, the agency with responsibility for rates and terms of service for interstate CO₂ pipelines must develop regulations. The Federal Energy Regulatory Commission (FERC) has the statutory responsibility to regulate sites, rates, and terms for interstate natural gas pipelines. However, FERC does not appear to have legal authority over CO₂ pipelines. The Surface Transportation Board (STB) has jurisdiction over pipelines that transport any commodity other than water, gas, or oil.³¹ But STB's predecessor interpreted its statutory authority to exclude all gas types, including CO₂. Thus it would appear that legislation is needed to establish which agency will regulate pipelines used for CO₂ transport.³²

If pipelines are to be constructed, "not in my backyard" (NIMBY) opposition should be expected. In Montana, H.B. 338 became law on April 16, 2009, which grants owners of pipelines transporting CO₂ common carrier status. This allows them to use eminent domain over private property owners.³³

§ 1(c). CO₂ Storage

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 formation as a CO₂ repository.³⁴ The Energy Independence and Security Act of 2007 requires the U.S. Geological Survey (USGS) to develop a methodology to determine the capacity for CO₂ sequestration in the United States and to then assess the capacity.³⁵ On June 3, 2009, the Department of the Interior (DOI), in consultation with DOE, the Environmental Protection Agency (EPA), and USGS, issued this report recommending a framework for identifying suitable CO₂ storage sites.³⁶ The report is more conservative than DOE estimates because it does

³¹ 49 U.S.C. § 15301.

³² GAO, *supra* note 4, at 45.

³³ Perri Knize, *Montana Governor Signs Measures Easing Path to Carbon Sequestration, Transport*, 40 Env't Rep. (BNA) 1202 (May 22, 2009).

³⁴ THE FUTURE OF COAL, SUMMARY REPORT 44, *supra* note 20.

³⁵ Pub. L. No. 110-140 (2007).

³⁶ DOI, FRAMEWORK FOR GEOLOGICAL CARBON SEQUESTRATION ON PUBLIC LAND (2009).

not include coal deposits as potential sequestration sites;³⁷ it only evaluates available sites that are 3,000 to 13,000 feet deep; and it limits evaluation to sites that can store 2 million cubic meters of carbon dioxide or more. This amount could be emitted in a short time by a single coal-burning power plant. The report does evaluate oil and gas reservoirs and saline formations. Saline formations are deep beneath the surface and often are filled with water with a high salt content and topped with an impervious cap that prevents the loss of the sequestered CO₂ because of physical and geochemical trapping.³⁸ Issues of concern in the report include the effect of sequestration on mineral extraction and surface activities such as grazing, recreation, and community development. Sites also need to be evaluated for their potential to induce earthquakes.³⁹

CO₂ storage can be based on solubility trapping, hydrodynamic trapping, physical adsorption and mineral trapping. Solubility trapping involves salt water containing CO₂ sinking to the bottom of a rock formation. In hydrodynamic trapping the relatively buoyant CO₂ rises in the formation until it is trapped by rock, such as shale or carbonates, that inhibits migration of the CO₂ from the porous formations, such as sandstone, where it is stored. The pore spaces that will receive the CO₂ usually contain other gases and liquids, primarily brine, that will be displaced or have their pressure increased by the injection.⁴⁰ In physical adsorption CO₂ molecules are trapped at near liquid-like densities on micropore wall surfaces of coal seams or shales. In mineral trapping CO₂ reacts chemically with minerals in the geological formation and forms solid minerals. Mineral trapping results in the most stable form of geological CO₂ sequestration.⁴¹ It is expected that the CO₂ will be injected at depths of over 800 meters (2,600 feet) into geological formations that will sequester it for hundreds to thousands of years.⁴²

While CO₂ injection has been widely used to enhance oil recovery and to force methane out of coal beds for recovery and use,⁴³ we do not yet have much experience with injection on the scale that will be required for geological storage of CO₂ 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 CO₂, its mobility within subsurface formations, the corrosive properties of the gases in water, the impact of

³⁷ See NETL. Carbon Sequestration: Storage, http://www.netl.doe.gov/technologies/carbon_seq/core_rd/storage.html (last visited Dec. 30, 2010) (citing coal seams as one viable storage option for CO₂).

³⁸ Leora Falk, *U.S. Geological Survey Develops Methodology to Assess Carbon Dioxide Storage Potential*, 40 Env't Rep. (BNA) 618 (Mar. 20, 2009).

³⁹ Steven D. Cook, *Site Selection Criteria Recommended for Geologic Storage of Carbon Dioxide*, 40 Env't Rep. (BNA) 1292 (June 5, 2009).

⁴⁰ Alexandra B. Klass & Sara E. Bergan, *Carbon Sequestration and Sustainability*, 44 TULANE L. REV. 237, 248 (2008).

⁴¹ U.S. DEPT. OF ENERGY, NATIONAL ENERGY TECHNOLOGY LABORATORY, DOE/NETL CARBON DIOXIDE CAPTURE AND STORAGE RD&D ROADMAP 49 (DEC. 2010)

⁴² GAO, *supra* note 4, at 10.

⁴³ Cook, *Site Selection Criteria*, *supra* note 39.

the impurities in the flue gas, and the large volume of material that will need to be injected. The supercritical liquid will be injected, using proven technology, at a depth of about 800 meters (2,625 feet) in order to keep the CO₂ in a supercritical state where it cannot be distinguished whether it is in a liquid or a gas phase.⁴⁴

It is estimated by the International Energy Agency that about 10,000 large-scale CCS projects will be needed by 2050 to hold global warming to 3 degrees Celsius by the end of this century. There are now four: Sleipner in the North Sea and Snohvit in the Barents Sea, Norway, both operated by StatoilHydro; the Salah project in Algeria operated by British Petroleum, Somatrach and StatoilHydro; and the North Dakota facility discussed below.⁴⁵ Since 1996 the Sleipner project has captured about 3,000 metric tons of CO₂ per day from its natural gas extraction, and it is stored 800 meters under the North Sea's seabed in a saline reservoir.⁴⁶

Some CO₂ is captured at natural gas plants, but it is not sequestered.⁴⁷ The only coal-burning facility in North America that sequesters CO₂ 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, and in this process CO₂, sulfur dioxide and mercury are removed from the gas stream. The gas stream, which is 96% CO₂, 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 transported 205 miles by pipeline to an oil field near Weyburn, Saskatchewan, Canada where it is injected into one of thirty-seven injection wells used to enhance oil recovery. The facility began sequestering CO₂ in 2000. It handles 8,000 metric tons of CO₂ each day.⁴⁸ None of the four existing sequestration projects was designed for long-term storage. They all are used to enhance hydrocarbon recovery. However, it appears that some of the injected CO₂ may remain in the depleted oil reservoirs permanently.⁴⁹

The U.S. DOE on December 4, 2009, announced three new projects that will receive up to \$979 million in federal funds to be leveraged with \$2.2 billion in private funds to help demonstrate commercial size CCS deployment. American

⁴⁴ U.S. Envtl. Protection Agency, *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 carbon dioxide is 88 degrees F.

⁴⁵ 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 4, 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, fn 7 [hereinafter Klass & Wilson, *Liability*].

⁴⁶ GAO, *supra* note 4, at 28. A list of the sequestration projects throughout the world is maintained by the IEA available at <http://co2captureandstorage.info/co2db.php> (last visited Dec. 30, 2010).

⁴⁷ GAO, *supra* note 4, at 17.

⁴⁸ CO₂ Sequestration, available at <http://www.basinelectric.com:80/Gasification/CO2/index.html> (last visited Mar. 3, 2010).

⁴⁹ See Dakota Gasification Company, *Carbon Capture and Sequestration: The Greatest CO₂ Story Ever Told*, http://www.dakotagas.com/CO2_Capture_and_Storage/index.html (last visited Dec. 7, 2010).

Electric Power, Inc. will design, construct and operate a chilled ammonia capture process projected to capture 90 percent of the CO₂ from a 235 MW flue gas stream at the 1,300 MW Mountaineer Power Plant near New Haven, West Virginia. The CO₂ will be injected into two saline formations approximately 1.5 miles below the surface.⁵⁰ The Southern Company Services will retrofit a 160 MW flue gas stream at Alabama Power's Barry facility near Mobile, Alabama to capture CO₂ and sequester up to one million metric tons per year in deep saline formations.⁵¹ Summit Texas Clean Energy, LLC will capture 90 percent of the CO₂ at a 400 MW plant to be built near Midland-Odessa, Texas. The CO₂ will be compressed and transported to oilfields in the Permian Basin of West Texas to be used for enhanced oil recovery.⁵² President 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 ten commercial-scale sequestration projects operational by 2016.⁵³

Many technical problems need to be overcome in order to have a viable carbon storage program, but cost effective environmental protection requirements, settlement of the ownership issues concerning carbon storage, and resolution of long-term liability are also issues that need to be resolved. Perhaps the first step will be to define CO₂ for the purposes of a CCS program. The Interstate Oil and Gas Compact Commission (IOGCC) has defined CO₂ as "anthropogenically sourced CO₂ of sufficient purity and quality as to not compromise the safety and efficiency of the reservoir containing the CO₂."⁵⁴ While large-scale CCS has not yet occurred, a body of law has developed concerning enhanced oil recovery (EOR) and the use of geologic reservoirs for the storage of natural gas that can be used to help shape an appropriate legal regimen for CCS.

EOR usually involves a unitized operation where all owners receive a portion of the benefits coming from EOR. This reduces the potential conflicts since all property owners are participants. If operations have not been unitized, the operator would have significant exposure to tort or property-based litigation.⁵⁵ Natural gas storage requires compliance with the state law on ownership of the depleted oil and gas reservoir pore space. Under the Natural Gas Act of 1938 interstate pipelines have eminent domain powers that apply to subsurface storage facilities.⁵⁶ Storage of natural gas requires payment to the subsurface owner of the fair market value of the

⁵⁰ U.S. Dept. of Energy, *Secretary Chu Announces \$3 Billion Investment for Carbon Capture and Sequestration* (Dec. 4, 2009), available at <http://www.netl.doe.gov/publications/press/2009/09081-Secretary Chu Announces CCS Invest.html> (last visited Dec. 30, 2010).

⁵¹ *Id.*

⁵² *Id.*

⁵³ Lynn Garner, *Obama Establishes Interagency Task Force to Expedite Carbon Capture at Power Plants*, 41 Env't Rep. (BNA) 263 (Feb. 5, 2010).

⁵⁴ IOGCC, *Storage of Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for States and Provinces* 10 (2007).

⁵⁵ Victor B. Flatt, *Paving the Legal Path for Carbon Sequestration from Coal*, 19 DUKE ENVTL L. & POL'Y FORUM 211, 231 (2009).

⁵⁶ 15 U.S.C. § 717.

right to store natural gas, “but the law of valuation remains unclear in most states and is largely undecided.”⁵⁷

§ 2. Regional Sequestration Efforts

In an effort to control and influence greenhouse gas (GHG) regulation, some states work with the IOGCC, which represents the oil and gas interests of its thirty-eight member states and nine international affiliates and has been an advocate of states’ rights to govern petroleum resources within their borders.⁵⁸ Because IOGCC views CCS as one of the best available methods to deal with the CO₂ released from current methods of fossil-fueled electric power generation, it formed a Geological Sequestration Task Force in 2002. In 2007 the task force, now the Carbon Capture and Storage Task Force, produced a comprehensive model legal and regulatory framework for geologic storage of CO₂ that advocates state and provincial level regulation of stored CO₂.⁵⁹

Other efforts to control GHG regulation and influence federal policy led twenty-three eastern, mid-western and western states to participate in three different regional approaches to GHG control.⁶⁰ Although each group emphasizes different goals and uses different paths to regulate and enforce its policies, these regional bodies provide varying levels of cooperation, investment, and direction for addressing climate change issues. Since 2005, cap-and-trade programs have been the main approach favored by regional programs attempting to reduce emissions of GHGs, with some programs specifically incorporating CCS as one type of reduction method. The oldest and most developed group, the Regional Greenhouse Gas Initiative (RGGI), has quarterly allowance auctions that have raised over \$729 million.

Each of the three regional groups takes a different stance on how CCS will fit into its system. Recently, these regional groups have collaborated on policy and may be looking for broader influence on national solutions by adopting common approaches to dealing with GHGs and cap and trade regulations.⁶¹ The material that follows discusses these regional developments, but whether these efforts survive is

⁵⁷ Flatt, *supra* note 55, at 237 (citing Elizabeth J. Wilson & Mark A. de Figueiredo, *Geologic Carbon Dioxide Sequestration: An Analysis of Subsurface Property Law*, 36 Env'l L. Rep. 10114, 10116-18 (2006)).

⁵⁸ See, e.g., IOGCC. Strategic Plan: The Domestic Resource, <http://www.iogcc.state.ok.us/strategic-plan> (last visited Sept. 23, 2010).

⁵⁹ See IOGCC. States Are Best Positioned to Regulate Carbon Dioxide Storage, Report Concludes. IOGCC Press Release (Sept. 26, 2007), available at <http://www.iogcc.state.ok.us/states-are-best-positioned-to-regulate-carbon-dioxide-storage-report-concludes> (last visited Sept. 23, 2010).

⁶⁰ See generally Kirsten H. Engel, *Mitigating Global Climate Change in the United States: A Regional Approach*, 14 N.Y.U. ENVTL. L. J. 54 (2005).

⁶¹ See Three-Regions Offsets Working Group. *Ensuring Offset Quality: Design and Implementation Criteria for a High-Quality Offset Program*. May 2010, available at http://www.midwesternaccord.org/News%20Page/Three-Regions_Offset_Whitepaper%2005_17_10.pdf.

unknown. Federal legislation like the House-passed H.R. 2454 would block the use of state or regional programs from 2012 to 2017, even if the federal program does not begin in 2012 as called for in the legislation. The Senate bill S. 1733 also includes a moratorium on sub-national programs during 2012 to 2017, but it allows existing programs to continue until nine months after the first auction of federal allowances.⁶² But while federal legislation has stalled during 2010, the regional groups are pushing forward to establish policy and organize actual and projected GHG auctions.⁶³

§ 2(a). Regional Programs – IOGCC

While IOGCC's main mission is to help states develop regulatory policies to maximize their oil and gas resources, it established a task force on carbon sequestration because of member states' interest in "the most immediate and viable strategies available for mitigating the release of CO₂ into the atmosphere."⁶⁴ The resulting guide, issued in 2007, derived from the task force's conclusion that states had the best experience, expertise, and jurisdiction to regulate CCS.⁶⁵ IOGCC emphasizes state control rather than a regional approach, and the guide suggests legal regulations for CCS to facilitate and protect state interests.

IOGCC defines CO₂ as "anthropogenically sourced carbon dioxide of sufficient purity and quality as to not compromise the safety and efficiency of the reservoir to effectively contain carbon dioxide."⁶⁶ This definition is less precise than its previous definition, requiring 95% purity, to allow for "evolving capture technologies and new research regarding reservoir storage capabilities."⁶⁷ While IOGCC does not directly address legal issues associated with a cap and trade program, it does recommend that any regulatory frameworks for emissions trading should use the regulatory experience of the states, especially for natural gas and underground storage. Based on its analysis of states' experience with property rights, resource management, and tort issues such as trespass and damages, IOGCC makes the following recommendations related to CCS:

⁶² *Senate Brokers Climate Preemption Compromise*, XX CLEAN AIR REP. (Inside EPA) 21:36 (Oct. 15, 2009).

⁶³ See, e.g., Plan B - Going it alone: Regional Programs in North America. POINT CARBON (Feb. 25, 2010), available at <http://www.pointcarbon.com/research/cmana/1.1416963>; Brian J. Donovan. Regional Greenhouse Gas Cap-and-Trade Programs May Be the Solution. The Donovan Law Group, April 5, 2010, available at <http://donovanlawgroup.wordpress.com/2010/04/05/regional-greenhouse-gas-cap-and-trade-programs-may-be-the-solution/>.

⁶⁴ IOGCC, CO₂ Storage: A Legal and Regulatory Guide for States (Dec. 2007), available at <http://groundwork.iogcc.org/topics-index/carbon-sequestration/executive-white-papers/co2-storage-a-legal-and-regulatory-guide-fo> (last visited Dec. 30, 2010).

⁶⁵ *Id.* at 3.

⁶⁶ *Id.* at 32.

⁶⁷ *Id.* at 24.

- State oil and gas regulatory agencies are the most logical and best equipped agency to implement rules and regulations for CCS;
- CO₂ should be regulated as a resource rather than a waste or pollutant to allow beneficial uses;
 - As part of this paradigm, IOGCC emphasizes that CCS is an economic solution rather than just a regulatory necessity;
 - But, IOGCC also recommends a cradle to grave regulatory framework for CCS, much like that used for hazardous waste by the EPA;
- Control of long-term underground carbon storage rights should be a required part of site licensing for CCS and be under state control;
- Long-term storage rights should also include eminent domain or unitization powers to allow control of the entire storage reservoir;
- States should develop a two-stage closure process made up of an initial closure period, with liability still attached to the project manager, and a long-term post-closure period, with liability shifting to a state trust;
 - States must have the power to implement needed monitoring, verification, and remediation regulations in the post-closure phase
- States, rather than the EPA, should regulate the post-operational phase of storage.⁶⁸

With its main goal of protecting property rights, IOGCC advocates maintaining the status quo for regulation of CO₂ injections for EOR, which means the right to inject CO₂ is a property right, governed by the oil and gas lease. Only when active oil production has ceased and injection is for the distinct purpose of long-term storage would storage rights move into new regulatory territory. IOGCC recommends the state enter at this point to control long-term storage. If underground storage is a property right and carbon is a resource rather than a waste product, state laws and lease interpretations are the logical legal pathways for regulation.

While IOGCC is not focused on combating climate change, it raises important federalism issues that should be considered in any approach to regulating CO₂ and underground storage. However, issues of patchwork regulations, financing, developing infrastructure, free-riders and cost-sharing, business migration, and environmental justice involve inter-state issues that would benefit from a regional or national approach. The three programs discussed below are attempting to affect and control climate change from a regional perspective. But before discussing the individual programs, initial collaborative efforts between the three programs are introduced.

⁶⁸ *Id.* at 10-12.

§ 2(b). Regional Programs – Three-Regions Collaborative Process

There is speculation that because federal legislation seems to have stalled the three regional programs will link together to pressure and incentivize other states to adopt climate change strategies.⁶⁹ Collaboration between the three regional programs, however, has been limited. A white paper on offsets has been developed that provides common definitions and review processes.⁷⁰ It defines offsets and lays out minimum requirements an offset must meet to qualify for allowance credit under any of the three regional cap and trade programs. According to the document, an offset is “a project-based greenhouse gas emissions reduction or removal that occurs outside the capped emissions sector or sectors regulated by the cap-and-trade program.”⁷¹ To earn allowances for a regulated entity, each offset must meet the outlined standards to show it is real, additional, verifiable, permanent, and enforceable. These requirements and definition bring more clarity to the concept of offsets, which had somewhat different definitions and requirements under the three separate programs.

§ 2(c). Regional Programs – Regional Greenhouse Gas Initiative (RGGI)

Ten Northeastern and Mid-Atlantic states that are part of RGGI⁷² seek to reduce carbon emissions through a cap-and-trade “Budget Trading Program” imposed on the region’s fossil fueled electric generating facilities that have the capacity to produce 25 MW or more of energy.⁷³ The program seeks to stabilize CO₂ emissions at 2009 levels until 2014 and then gradually reduce emissions 2.5% a year to reach a 10% reduction by 2018.⁷⁴ On December 20, 2005, RGGI became the first mandatory regional greenhouse gas program.⁷⁵ The RGGI program does not attempt to regulate GHGs other than CO₂, although it allows offset projects for methane and sulfur hexafluoride. RGGI is implemented by each of the ten member states: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont.⁷⁶ Pennsylvania refused to join RGGI because of concerns that a cap-and-trade program aimed at power plants will

⁶⁹ Nathaniel Gronewold, *RGGI Gathering May Be First Step Toward Trading Revisions*, ENVIRONMENT AND ENERGY PUBLISHING, Aug. 25, 2010.

⁷⁰ RGGI, MGGRA, & WCI, Ensuring Offset Quality: Design and Implementation for a High-Quality Offset Program (May 2010), available at <http://www.westernclimateinitiative.org/component/repository/general/Ensuring-Offset-Quality-Design-and-Implementation-Criteria-for-a-High-Quality-Offset-Program/> (last visited Dec. 30. 2010) [hereinafter Tri-Regional Offsets]

⁷¹ *Id.*, at 6.

⁷² RGGI, About RGGI, available at <http://www.rggi.org/about> (last visited Dec.30, 2010).

⁷³ RGGI, RGGI Model Rule, at 20, available at http://www.rggi.org/design/history/model_rule (last visited Dec. 30, 2010) [hereinafter RGGI Model Rule].

⁷⁴ RGGI, RGGI Fact Sheet, available at http://www.rggi.org/design/fact_sheets (last visited Dec. 30, 2010) [hereinafter RGGI Fact Sheet].

⁷⁵ *Id.*

⁷⁶ XIX CLEAN AIR REPORT (Inside EPA) 1: 24 (Jan. 10, 2008).

increase emissions as power distributors purchase lower cost out-of-state power.⁷⁷ Each state is to implement a CO₂ control program using the RGGI Model Rule⁷⁸ (Model Rule) as a guide to state regulation, and each state is to designate a state regulatory agency, typically the Department of Environmental Quality, to administer the program.⁷⁹

The RGGI program approval was aided by the fact that all of the involved states were at various stages of developing a CO₂ control program. New Jersey was the first state to develop a GHG reductions plan aimed at reducing CO₂ by 3.5 percent by 2005.⁸⁰ On April 20, 2007, Maryland became the last state to formally join RGGI.⁸¹ Each state establishes emission limits for electric power plants, creates carbon dioxide allowances, and determines appropriate allocations. The state regulations may be found on the RGGI web site.⁸²

The ten participating states agreed to stabilize emissions from electric power plants at the 2009 level of 188 million tons per year until 2014 and to reduce CO₂ by 2.5 percent per year for four years beginning in 2015.⁸³ Each regulated electric power plant received a cap and must hold enough allowances to cover its emissions. The states retain at least twenty-five percent of their total allowances to sell to power plants and use the money for programs that promote energy efficiency, energy conservation, or to provide rebates to consumers. These goals were seen as relatively modest when the program began, and since they were set, a nation-wide recession and falling natural gas prices have already led to a 34% reduction in regional emissions. Thus, under the current cap goals, most sources will reach their final reduction goals without having to make any additional changes.⁸⁴

The RGGI Model Rule allows emission sources to invest in CO₂ "offset" projects and deduct the resulting sequestered or avoided CO₂ from their total emissions for the year.⁸⁵ While the definition and regulation of offsets has been updated by the Tri-Regional whitepaper, the Model Rule provides more specific guidelines for the amount and type of offsets regulated entities can use. Power plants may offset up to 3.3 percent of their GHG emissions.⁸⁶ However, the Model Rule provides that if the market prices for an allowance exceed \$7.00 in 2005 dollars⁸⁷ the percentage of allowable offset deductions is raised to five percent,⁸⁸

⁷⁷ Dean Scott, *Concerns Over Potential Emissions "Leakage" Keep Pennsylvania Out of Regional Initiative*, 39 Env't Rep. (BNA) 263 (Feb. 8, 2008).

⁷⁸ See generally, RGGI, Model Rule, *supra* note 73.

⁷⁹ RGGI, Participating States, <http://www.rggi.org/states> (last visited Dec. 30, 2010).

⁸⁰ *Id.*

⁸¹ See <http://www.rggi.org/design/regulations> (last visited Dec. 30, 2010).

⁸² <http://www.rggi.org/design/regulations> (last visited Dec. 30, 2010).

⁸³ Martha Kessler, *Connecticut Official Says States Not Ready To Cede Role in Developing Climate Policy*, 39 Env't Rep. (BNA) 2355 (Nov. 28, 2008).

⁸⁴ See Gronewold, *supra* note 69.

⁸⁵ See generally RGGI Model Rule, *supra* note 73, at Subpart xx-10.

⁸⁶ *Id.*, at xx- 6.5(a)(3)(i).

⁸⁷ *Id.* at xx-1.2(b)(j).

and if the price of an allowance exceeds \$10.00 in 2005 dollars,⁸⁹ the percentage of allowable offset deductions is raised to ten percent.⁹⁰ As of December 28, 2010, allowances were available for \$1.86, making the possibility of additional offsets.⁹¹

The Model Rule recognizes five offset projects: 1) landfill methane capture and destruction, 2) reduction in emissions of sulfur hexafluoride (SF₆), 3) sequestration of carbon due to afforestation; 4) reduction or avoidance of CO₂ emissions from natural gas, oil, or propane end-use combustion due to end-use energy efficiency; and 5) avoided methane emissions from agricultural manure management operations.⁹² The only sequestration of CO₂ allowed under RGGI is the biological sequestration of carbon in trees through the afforestation process. The RGGI program does not address geological sequestration.

The RGGI program was challenged in New York by a natural gas-fired cogeneration plant, seeking to overturn the state's regulations that implement the RGGI.⁹³ The lawsuit claimed the RGGI violated the compact clause of the U.S. Constitution, and that the cap and trade program was an impermissible tax that was not authorized by the state legislature. However, the major concern of the litigant was that it would not be able to pass the cost on to the buyer of its electricity as other providers could because it has a long-term fixed price contract with Consolidated Edison.⁹⁴ The parties reached a settlement agreement in December of 2009, which preserved New York's participation in RGGI by negotiating a way for Indeck Corinth to recover the costs of CO₂ allowances. "Under the terms of the settlement, Con Edison will pay the cogeneration plants for costs they incur in purchasing carbon dioxide emissions allowances at RGGI auctions. The state, in turn, will essentially reimburse Con Edison by making about \$2.6 million in annual investments in the company's infrastructure and smart grid technologies."⁹⁵ Thus, the court never ruled on the constitutional legitimacy of RGGI, but the cogeneration plant is participating in the cap and trade program through concessions from the state and its electricity purchaser.

RGGI CO₂ auctions produced \$729 million in nine auctions over two years. According to regulatory documents, and about two-thirds of the money should be invested in energy efficiency and alternative energy technologies, which would reduce the need for CCS. However, in 2009 both New York and New Jersey used

⁸⁸ *Id.* at xx 6.5(a)(3)(ii).

⁸⁹ *Id.* at xx-1.2(b)(l).

⁹⁰ *Id.* at xx-6.5(a)(3)(iii).

⁹¹ See the RGGI website at <http://www.rggi.org/home>.

⁹² RGGI Model Rule, *supra* note 73, at xx-10.3(a)(1)(i)-(v).

⁹³ Indeck Corinth, L.P. v. Paterson, Case No. 2009 369, RJI No. 2009/0369 (N.Y. Supr. Ct.).

⁹⁴ Gerald B. Silverman, *Cogeneration Plant Sues New York to Overturn State's RGGI Regulations*, 40 Env't Rep. 302 (Feb. 6, 2009); Gerald Silverman, *State Agency Approves Spending Plan for Proceeds from RGGI Allowance Auction*, 40 Env't Rep. (BNA) 1023 (May 1, 2009). See also <http://www.nyserdarg/RGGI/default.asp> (last visited Dec. 30, 2010).

⁹⁵ Gerald B. Silverman. State Settles Lawsuit with Plant Owners that Challenged Implementation of RGGI. 41 Env't Rep. (BNA) 36 (Jan. 1, 2010).

\$155 million from these funds to reduce their deficits, and despite specific funding requirements in RGGI documents, it doesn't appear that RGGI has any legal authority over how states use their funds.⁹⁶ The clearing price for allowances sold in the June 2010 auction was \$1.86, down from the initial price of \$3.07 and a high of \$3.51 in March of 2009. Ninety-two percent of the allowances for immediate use and all the allowances for use after 2013 were purchased by electric power generators.⁹⁷ After the recession lowered demand for electricity, sales of allowances went down thirty-three percent from 2005 compared to 2009. Besides the recession, lower demand for electricity was attributed to increased use of nuclear and wind generated power, and fuel switching due to lower natural gas prices.⁹⁸ The market for allowances has collapsed, and the Chicago Climate Exchange is ending GHG allowance trading at the end of 2010.⁹⁹

§ 2(d). Midwest Regional Greenhouse Gas Reduction Accord (MGGA)

On November 15, 2007, nine governors of Midwest states and the Premier of Manitoba signed the Midwest Regional Greenhouse Gas Reduction Accord.¹⁰⁰ The states now participating are Wisconsin, Minnesota, Illinois, Iowa, Michigan, Kansas and South Dakota as well as Manitoba. Indiana, Ohio and Ontario are participating as observers. Nebraska and North Dakota are cooperating with the Accord states in regional initiatives to address climate change. The Midwest Accord states seek to reduce GHG emissions through a regional cap-and-trade system and complimentary policies that encourage regional development of renewable energy, energy efficiency, biofuels, and carbon capture and storage.¹⁰¹ In addition, the MGGA has established GHG reduction targets and timeframes consistent with member states' targets. It has also established tracking, management, and crediting systems, and more than any other regional group, MGGA has embraced CCS as an important and effective regional resource for reducing carbon emissions.¹⁰² It developed specific carbon sequestration goals, paths to commercialization, and legal and regulatory models to encourage both more carbon capture and state policies to facilitate the

⁹⁶ See Steve Jones. Preemption of Regional Climate Compacts: A Hot Topic in the Global Warming Debate. 2010 EMERGING ISSUES 5016 (May 6, 2010); Environmentalists to Push RGGI Expansion During Program Review. CARBON NEWS, Aug. 30, 2010.

⁹⁷ See RGGI, Auction Results, available at <http://rggi.org/home> (last visited Dec. 30, 2010); Gerald B. Silverman, *Regional Initiative Carbon Allowances Sell for \$1.88 Each in Eighth Auction*, 41 Env't Rep. (BNA) 1357 (June 18, 2010).

⁹⁸ Gerald B. Silverman, *Report Says Carbon Dioxide Emissions Fell by 60.7 Million Tons in RGGI States*, 41 Env't Rep. (BNA) 2512 (Nov. 12, 2010); Gerald B. Silverman, *RGGI Sells Carbon Dioxide Allowances For \$1.86 Each, Raises \$66.4 Million*, 41 Env't Rep. (BNA) 2064 (Sept. 17, 2010).

⁹⁹ Leora Falk, *Chicago Climate Exchange to Halt Trading At Year's End, Will Become Offset Registry*, 41 Env't Rep. (BNA) 2406 (Oct. 29, 2010).

¹⁰⁰ Available at <http://www.midwesternaccord.org> (last visited Dec. 30, 2010).

¹⁰¹ See MGA, MIDWESTERN ENERGY SECURITY AND CLIMATE STEWARDSHIP ROADMAP (2009), available at <http://www.midwesterngovernors.org/publications.htm> (last visited Sept. 29, 2010).

¹⁰² See MGGA, FINAL MODEL RULE FOR THE MIDWESTERN GREENHOUSE GAS REDUCTION ACCORD. April 2010, available at <http://www.midwesternaccord.org/> (last visited Sept. 29, 2010) [hereinafter MGGA Model Rule].

infrastructure needed for transportation and storage of CO₂.¹⁰³ One of the most important methods for making CCS an economically viable technology, the MGGA cap and trade program is scheduled to begin in January of 2012, with a final model rule released in April of 2010.¹⁰⁴

The 2007 Midwest Accord document does not specifically mention geologic carbon sequestration or geologic storage, but the *Energy Security and Climate Stewardship Platform for the Midwest* (MGA Platform) that was released by the Midwestern Governors Association (MGA) to accompany the 2007 Accord has as its third listed objective to "(i)mplement geologic CO₂ storage, terrestrial carbon sequestration and other technological utilization of CO₂ on a large scale."¹⁰⁵ To fulfill the carbon sequestration objective the MGA Platform seeks as a key strategy to "(a)ccelerate the commercialization of advanced coal and natural gas technologies and infrastructure for the capture and geologic storage of CO₂ emissions, including for enhanced oil and gas recovery."¹⁰⁶

The MGA Platform enumerates specific goals and measures, and a "Cooperative Regional Initiative" specifies how member states are to achieve their carbon sequestration goals.¹⁰⁷ In fulfillment of one of these goals, MGA released a regulatory "Toolkit" in 2009, providing a regulatory framework to enable permanent geologic storage and clear direction to allow for CO₂ capture, injection, monitoring, verification and compliance, and address liability for stored CO₂.¹⁰⁸ The MGA Toolkit suggests statutory and regulatory actions states can take to promote CCS, broken down by issues related to transport, ownership, and liability and financial responsibility. The Toolkit is based on the IOGCC's regulatory framework and World Resources Institute CCS guidelines as well as a regional survey of state statutes and regulations. Key markers for the Platform include siting and permitting for a multi-jurisdictional pipeline by 2012 to transport CO₂ from power plants to a reservoir for use in enhanced oil and gas recovery. By 2012 the region should also have at least one commercial-scale IGCC power plant using bituminous coal that uses CCS. By 2015 the region plans to have three or more commercial-scale IGCC plants with CCS that use bituminous coal, at least one IGCC plant with CCS that uses

¹⁰³ See MGGA, ADVISORY GROUP FINAL RECOMMENDATIONS May 2010, available at <http://www.midwesternaccord.org/> (last visited Dec. 30, 2010); Midwestern Governors Association (MGA); MGA, REGIONAL COMMERCIAL PLAN FOR CARBON CAPTURE AND STORAGE Sept. 2009, available at <http://www.midwesterngovernors.org/energy.htm> (last visited Dec. 30, 2010) [hereinafter MGA Commercial Plan]; MGA, LEGAL AND REGULATORY INVENTORY FOR CARBON CAPTURE AND STORAGE & ANALOGUES, Mar. 2009, available at <http://www.midwesterngovernors.org/energy.htm> (last visited Dec. 30, 2010) [hereinafter MGA Inventory]; MGA, TOOLKIT FOR CARBON CAPTURE AND STORAGE: STATUTORY AND REGULATORY ISSUES, Mar. 2009, available at <http://www.midwesterngovernors.org/energy.htm> (last visited Dec. 30, 2010)[hereinafter MGA Toolkit].

¹⁰⁴ MGGA Model Rule, *supra* note 102.

¹⁰⁵ MGA, ENERGY SECURITY AND CLIMATE STEWARDSHIP PLATFORM FOR THE MIDWEST, at 4 (2007) [hereinafter MGA Platform].

¹⁰⁶ *Id.* at 5.

¹⁰⁷ *Id.* at 18-27.

¹⁰⁸ MGA TOOLKIT, *supra* note 103, at 4.

sub-bituminous coal, at least one plant with CCS that uses lignite coal, and one or more pulverized coal plants that use commercial scale post-combustion CO₂ capture of emissions. By 2020 all new coal gasification and coal combustion plants are to capture and store CO₂ emissions, and by 2050 the region's fleet of coal plants will have transitioned to CCS.¹⁰⁹

A 2009 Roadmap laid out four priorities for regional development of advanced coal and CCS.¹¹⁰ The first priority, to develop a legal and regulatory framework for CCS, was fulfilled by release of the Toolkit and Inventory. States may now modify Toolkit models to fit their own situations. The second priority is to lay the groundwork for a Geologic Storage Utility. A Geologic Storage Utility would serve some of the same functions as the IOGCC state trust discussed above, such as taking long-term responsibility for stored CO₂ and assuring that an entire storage reservoir is under a single managing entity. But the MGA plan envisions an even broader role.

Such a utility could facilitate the development of the commercial CCS industry in the region by taking responsibility for the planning, development, financing, management and long-term site stewardship associated with multiple projects developed in storage formations such as deep saline formations that may cross jurisdictional boundaries. Centralized coordination of such projects would reduce the complexity of managing multiple geologic storage projects in the same geologic formation and provide certainty and transparency to accelerate scale-up of the industry.¹¹¹

The MGA Commercial Plan also identifies establishment of a Geologic Storage Utility as an important assurance for CCS developers because it will provide a "more stable and predictable environment" as well as relieving long-term liability concerns.¹¹²

The Roadmap's third CCS priority is to use the long-term experience and commercial nature of EOR to incentivize CO₂ storage. Both the Roadmap and Commercial Plan emphasize EOR as the best pathway to develop the necessary technology, funding, and legal framework for large-scale, commercial CCS.¹¹³ The Natural Resources Defense Council also sees the integration of CCS and EOR as a positive development for reducing GHGs:

¹⁰⁹ MGA Platform, *supra* note 105, at 18.

¹¹⁰ MGA, MIDWESTERN ENERGY SECURITY AND CLIMATE STEWARDSHIP ROADMAP (2009), available at <http://www.midwesterngovernors.org/energy.htm> (last visited Dec. 30, 2010) [hereinafter MGA ROADMAP].

¹¹¹ *Id.* at ix.

¹¹² MGA COMMERCIAL PLAN, *supra* note 103, at 6, 12.

¹¹³ See *id.* at 9; MGA ROADMAP, *supra* note 110, at ix.

CO₂-EOR has a substantial immediate to long-term role to play in both increasing domestic oil production in a responsible way, and in sequestering CO₂ underground. Policies that incentivize the capture of industrial CO₂ can help the country access an untapped domestic oil resource while reducing global warming pollution.¹¹⁴

The Platform recommends that states and industry assist existing small to medium oil and gas producers in finding EOR methods that are cost effective.¹¹⁵ States should support comprehensive assessments of geologic reservoirs at the state and federal levels to determine the CO₂ storage potential and feasibility. The Commercial Plan outlines two phases to expand CCS commercially: Phase I (through 2015) develops commercial scale capture projects and associated infrastructure related to EOR projects in Kansas, Manitoba, Michigan, Missouri, and North Dakota. It also develops a CO₂ pipeline to connect capture projects in Illinois, Indiana, Kentucky, and Ohio to Gulf Coast EOR projects. Phase II (2015-2025) expands the pipeline network and connects all Midwest jurisdictions by pipeline so that states lacking geologic storage capacity can still capture CO₂ and transport it to other Midwestern states for storage.¹¹⁶ MGA recommends funding large-scale geologic storage tests to assist in developing commercial storage capability.¹¹⁷ Member states can evaluate the feasibility of CO₂ transport and advanced sequestration to assist jurisdictions without geologic storage potential.¹¹⁸

The Roadmap's fourth priority is to reduce capital costs of CCS projects and pipelines. The Platform provides suggestions for financial and regulatory incentives to build advanced coal generation projects with CCS.¹¹⁹ For example, states should enact state tax incentives for front-ended engineering and design studies for power plant costs.¹²⁰ States should match the Energy Policy Act of 2005 plant development incentives and should assure cost recovery for approved advanced coal projects that use CCS technology.¹²¹ States should encourage low-CO₂ coal technologies and modify state policies and regulatory programs to favor advanced generation technologies that limit CO₂ emissions and use CCS to replace conventional pulverized coal units.¹²² The Platform lists several specific means to achieve this goal including, *inter alia*, requiring a low carbon electricity portfolio standard, a CCS portfolio standard, and market-based regulatory programs to encourage investment in low carbon technologies.¹²³ It also advocates incentives for deployment of

¹¹⁴ Natural Resources Defense Council, *Tapping into Stranded Domestic Oil: Enhanced Oil Recovery with Carbon Dioxide is a Win-Win-Win*, July 2008, available at <http://www.nrdc.org/energy/eor.pdf> (last visited Dec. 30, 2010).

¹¹⁵ MGA PLATFORM, *supra* note 105, at 20.

¹¹⁶ MGA COMMERCIAL PLAN, *supra* note 103, at 7-8.

¹¹⁷ MGA PLATFORM, *supra* note 105, at 20.

¹¹⁸ *Id.*

¹¹⁹ *Id.* at 22.

¹²⁰ *Id.* at 23.

¹²¹ *Id.*

¹²² *Id.*

¹²³ *Id.*

innovative coal gasification technologies, including co-gasification of biomass and underground coal gasification, and the utilization of captured CO₂.¹²⁴

To support advanced coal and CSS technology, the member states made specific resolutions.¹²⁵ Several of these resolutions have now been fulfilled.

1. Quantify the potential costs and benefits of EOR: This resolution was at least partly fulfilled by an Advanced Resources International report submitted to MGA in June of 2009. It examines the technical and economic potential of EOR using CO₂ in 8 of the 12 midwestern states.¹²⁶
2. Expand assessment of geologic reservoirs for CO₂ storage in Partnership states that lack oil and gas bearing formations known to be suitable for CO₂ injection and storage, notably Minnesota and Wisconsin.
3. Produce a state-by-state inventory of Partnership member's regulations governing or potentially relating to CO₂ capture, compression, pipeline transportation, and underground injection. This resolution was fulfilled by the MGA Inventory discussed above.¹²⁷
4. Develop a uniform regional model state regulatory framework specific to CO₂ capture, compression, pipeline transport, and underground injection and storage, informed by emerging federal approaches and the draft Interstate Oil and Gas Commission regulations due out in 2007: This resolution was fulfilled by the MGA Toolkit discussed above. MGA's most recent meeting discussed ways to implement this framework either state or regionally.¹²⁸
5. Study and propose a regional pipeline system serving more than one Partnership member (and possibly connecting Partnership members with other regions) that links one or more sources of captured CO₂ with appropriate geologic reservoirs (e.g. Illinois Basin and Michigan, Ohio and Northern Plains EOR formations) and injection and storage facility for EOR and deep saline aquifer storage: While the pipeline system has been proposed, there is still much more work to be done before it can be actualized.¹²⁹

¹²⁴ *Id.* at 25.

¹²⁵ *Id.* at 27.

¹²⁶ MGA, CO₂-ENHANCED OIL RECOVERY POTENTIAL FOR THE MGA REGION (June 2009), available at <http://www.midwesterngovernors.org/energy.htm> (last visited Dec. 30, 2010).

¹²⁷ See MGA INVENTORY, *supra* note 103.

¹²⁸ MGA, CARBON CAPTURE AND STORAGE TASK FORCE: MEETING ONE NOTES, Columbus, OH, Aug. 25-26, 2010, available at <http://www.midwesterngovernors.org/CCS.htm> (last visited Dec. 30, 2010).

¹²⁹ See MGA COMMERCIAL PLAN, *supra* note 103, at 7 (showing map of proposed pipeline systems).

6. Create a Partnership-wide commercial plan for CO₂ management that incorporates the above elements and emphasizes EOR as important step toward deep saline aquifer CO₂ storage: This resolution was fulfilled by the MGA Commercial Plan.
7. Coordinate Partnership FY 2009 request for federal investment in CO₂ capture and storage infrastructure in the MGA region.

In May 2010 the MGGA's Advisory Group Final Recommendations (Final Recommendations) was released.¹³⁰ The Final Recommendations do not directly discuss CSS, but the broader workings of the program combined with the above MGA initiatives identify the role CSS may play in the implementation of the Midwestern Accord.

The Final Recommendations recommend reducing emissions of the six GHGs 20% below 2005 levels by 2020 and 80% below 2005 levels by 2050. These goals are subject to revision and updates based on technology and program results.¹³¹ The first deliverer of electricity,¹³² industrial combustion sources, and the final blender or distributor of transportation or other residential, commercial, or industrial combustion fuels (covered sectors) are the regulatory targets.¹³³ Entities with annual emissions greater than 25,000 metric tons, calculated on a three-year rolling average, will be subject to the program. If emissions from any source drop below 25,000 metric tons for a three-year period, that source can apply for exemption from the program.¹³⁴ Electric units generating less than 25 MW of energy or that are fueled using 100 percent biomass are exempt from regulation. Entities in the covered sectors producing more than an annual equivalent of 20,000 metric tons of CO₂ must begin collecting GHG emission data in January 2010 and begin reporting emissions to the Climate Registry Information System¹³⁵ in 2011.¹³⁶ The Midwestern Accord is to become effective January 2012.¹³⁷

Each participating jurisdiction¹³⁸ is responsible for implementing, regulating, and enforcing the provisions of the Midwestern Accord's cap-and-trade program

¹³⁰ MGA. ADVISORY GROUP FINAL RECOMMENDATIONS (2010), *available at* <http://www.midwesternaccord.org> (last visited Dec. 30, 2010) [hereinafter MGA Final Recommendations].

¹³¹ *Id.* at Recommendation 1.1.

¹³² For electricity produced and sold within a participating jurisdiction the first deliverer is the generator of the electricity; for electricity generated outside a jurisdiction but sold inside a participating jurisdiction, the first deliverer is the entity that first delivers the electricity into the participating jurisdiction. *Id.* at Recommendation 2.4.1.

¹³³ *Id.* at Recommendation 2.4.

¹³⁴ *Id.* at Recommendation 2.5.

¹³⁵ See generally The Climate Registry, <http://www.theclimateregistry.org> (last visited Dec. 30, 2010).

¹³⁶ MGA FINAL RECOMMENDATIONS, *supra* note 130, at Recommendation 5.0.

¹³⁷ *Id.* at Recommendation 7.1.

¹³⁸ The participating jurisdictions are Kansas, Illinois, Iowa, Michigan, Minnesota, and Wisconsin, and Manitoba. *Id.* at Introduction.

and must create an accounting system for allowances and/or offsets.¹³⁹ Each regulated entity will demonstrate compliance by surrendering allowances matching their emissions to the appropriate state regulatory agency¹⁴⁰ or surrender penalty allowances or pay a fee for every metric ton of CO₂e not accounted for.¹⁴¹ States may also levy additional penalties and fees.¹⁴² Regulated entities will make public all emission records that are not subject to confidentiality.¹⁴³ The Final Recommendations also recommend each jurisdiction establish market oversight rules to promote sounds markets and prevent fraud.¹⁴⁴ These rules should be “a flexible and adaptive cost containment framework that includes a desired trading price range,” stability, avoidance of market failure triggers, and “orderly operation of the allowance trading market.”¹⁴⁵ The Final Recommendations also recommend linking the Midwestern Accord to other GHG reduction programs including RGGI, the Western Climate Initiative, and the European Emission Trading System.¹⁴⁶

The Final Recommendations recommend dividing the regional cap between participating states based primarily on their relative emissions.¹⁴⁷ However, the Final Recommendations also provide room for some of the allowance budget to be apportioned using other criteria like emissions per capita, population and economic growth, or new and projected emission sources.¹⁴⁸ Proceeds from allowances are to be used solely for climate change purposes.¹⁴⁹ Funds should be used for: 1) accelerating transformational investments, like the IGCC, CSS, and low carbon technologies recognized in the MGA Platform; 2) mitigating transitional adverse impacts of the program; and 3) addressing harmful impacts due to climate change.¹⁵⁰

The Midwestern Accord envisions each jurisdiction deciding how and whether to allocate or auction allowances, but the Final Recommendations suggest general and specific allowance distribution mechanisms. On the general side, it is recommended each participating jurisdiction: 1) annually place two percent of their allowances in a reserve pool for cost containment to prevent excessively high or low allowance prices;¹⁵¹ 2) enact strong legal mechanisms safeguarding allowance value, ensuring allowance profits are used for climate purposes, the distribution is

¹³⁹ *Id.*, at Recommendation 6.1, 6.4 & 5.

¹⁴⁰ *Id.* at Recommendation 6.2.

¹⁴¹ *Id.* at Recommendation 6.3.

¹⁴² *Id.* at Recommendation 6.3.

¹⁴³ *Id.*

¹⁴⁴ *Id.* at Recommendation 8.1.

¹⁴⁵ *Id.* at Recommendation 8.2.

¹⁴⁶ *Id.* at Recommendation 2.8.

¹⁴⁷ *Id.* at Recommendation 3.1.

¹⁴⁸ *Id.*

¹⁴⁹ *Id.* at Recommendation 3.3

¹⁵⁰ *Id.* See also Recommendations 3.3.1 et seq. (specific means of Transformational Investment like retooling the Midwestern manufacturing industry, costs to end uses like low-income consumers and energy-intensive industries., cap-and-trade program costs, and worker training and educational programs).

¹⁵¹ *Id.* at Recommendation 3.5.1.

transparent, and market manipulation and speculation are minimized;¹⁵² and 3) create mechanisms that prevent windfall profits.¹⁵³

On the more specific side, the Final Recommendations recommend a hybrid distribution method that would, for the first three-year compliance period, auction some of the allowances and allocate the rest.¹⁵⁴ Under this method a set percentage of the total regional allowances, a suggested five percent, would be auctioned regionally and the proceeds directed to regional programs like the Low-Carbon Technology Commercialization Fund.¹⁵⁵ Complimenting the regional auction, it is recommended jurisdictions attach a modest fee to the remaining allowances and allocate them between the transportation, utility, merchant power, and industrial sectors in proportion to their GHG emissions, without discriminating against combined heat and power. It is also recommended that all allowances for the industrial sector be allocated rather than auctioned for the first two compliance periods and then gradually transitioned to full action in line with the all other allowances.¹⁵⁶ The Final Recommendations suggest that after the initial three compliance periods, the states transition to a full auction system.¹⁵⁷

Like the Tri-Regional Offset recommendations, the MGGA Final Recommendations suggest each jurisdiction develop a carbon-offset program that is “real, additional, verifiable, permanent, and enforceable.”¹⁵⁸ To make these programs effective, offsets should be regionally reviewed and approved. Material on offset protocols and criteria that was present in the draft of the final recommendations was removed from the final version. The Tri-Regional Offsets whitepaper was produced during this time, and it contains information on offset protocols and criteria that has now been adopted by the MGGA.¹⁵⁹ Collaboration with the other regions on offsets furthers MGGA’s goal outlined in the draft materials to standardize offset protocols and criteria as much as possible.

The Midwest Regional Sequestration Partnership announced on October 21, 2009, that it had successfully injected 1,000 tons of liquefied carbon dioxide into rock beneath the Duke Energy’s East Bend Generating Station in Boone County, Kentucky. The partnership expects to inject 1 million tons of carbon dioxide into the Mount Simon Sandstone formation that lies beneath parts of Iowa, Illinois, Wisconsin, Michigan, Ohio, Kentucky, and Missouri.¹⁶⁰

¹⁵² *Id.* at Recommendation 3.5.2.

¹⁵³ *Id.* at Recommendation 3.5.3.

¹⁵⁴ *Id.* at Recommendation 3.5.4.

¹⁵⁵ *Id.* at Recommendation 3.5.4.1.

¹⁵⁶ *Id.* at Recommendation 3.5.4.2.1-4 (see individual sections for more specific restrictions and criteria for each sector).

¹⁵⁷ *Id.* at Recommendation 3.5, 3.6 & 4.3.

¹⁵⁸ *Id.* at Recommendation 4.1, 4.2 (defining real, additional, verifiable, permanent, enforceable).

¹⁵⁹ See Tri-Regional Offsets, *supra* note 70.

¹⁶⁰ Leora Falk, *Regional Partnership Successfully Injects Carbon Dioxide Underground in Test Project*, 40 Env’t Rep. (BNA) 2454 (Oct. 23, 2009).

§ 2(e). Western Climate Initiative (WCI)

On February 26, 2007, the governors of Arizona, California, New Mexico, Oregon and Washington signed the Western Climate Initiative (WCI) to develop regional strategies to address climate change. Subsequently Utah, Montana and the Canadian provinces of British Columbia, Manitoba, Ontario and Quebec joined. In addition, fourteen U.S. and Mexican states and Canadian provinces of Saskatchewan and Nova Scotia are official observers.¹⁶¹ The WCI is a non-enforceable agreement that does not create binding legal obligations. The parties expect the WCI program to be self-enforcing because its members benefit from mutual collaboration as a method of improving each state's individual GHG control efforts. The WCI set an overall regional goal to reduce GHG emissions to 2005 levels by 2020, which is about a 15 percent reduction. Each member must voluntarily establish a program to reach the reduction goal that includes controls on stationary and mobile sources. WCI has designed a market-based cap-and-trade program to achieve the regional reduction goal. As with all WCI initiatives, member participation is discretionary, and at this point, the only U.S. states having committed to begin on the program start date of January 1, 2012 are California and New Mexico. The WCI agreement promotes does not provide specific goals, but its aim is to have both independent and collaborative efforts by the participating states to develop a regional approach while still respecting "the interests, needs, and circumstances of each jurisdiction."¹⁶² Although it touts the benefits of a cap-and-trade program with a broad scope and geographic coverage, WCI is willing to accommodate "alternative schedules for implementation."¹⁶³

On July 27, 2010, the WCI released its "Design for the WCI Regional Cap-and-Trade Program," which is modeled after existing cap-and-trade plans such as RGGI, EPA's Acid Rain Program, and the United Kingdoms Emissions Trading Scheme.¹⁶⁴ WCI will require allowances for any source with emissions greater than 25,000 metric tons per year. It will also require allowances for deliverers of electricity that generate more than 25,000 metric tons per year to produce the delivered energy, and for any fossil fuel supplier within the jurisdiction whose sold fuel in the jurisdiction would emit 25,000 metric tons or more when combusted.¹⁶⁵ The cap-and-trade program will be implemented in two phases: Phase I starts in 2012 and will cover emissions from electricity, electricity imports, industrial combustion at

¹⁶¹ See <http://westernclimateinitiative.org> (last visited Dec. 30, 2010); Peter Menyasz, *Quebec Joins Western Climate Initiative, Will Participate in Emissions Trading Scheme*, 39 Env't Rep. (BNA) 800 (Apr. 25, 2008).

¹⁶² WCI, CLEAN ENERGY: CREATING JOBS, PROTECTING THE ENVIRONMENT, available at brochure, www.westernclimateinitiative.org (last visited Dec. 30, 2010).

¹⁶³ WCI, DESIGN FOR THE WCI REGIONAL CAP-AND-TRADE PROGRAM, at 6 (July 2010), available at www.westernclimateinitiative.org (last visited Dec. 30, 2010) [hereinafter WCI Design].

¹⁶⁴ *Id.* See also WCI, Markets Committee Task 6: Auction Design White Paper, 4 (April 14, 2010), available at <http://westernclimateinitiative.org/the-wci-cap-and-trade-program/program-design> (last visited Dec. 30, 2010).

¹⁶⁵ WCI DESIGN, *supra* note 191, DD-13-14. Eligible biomass emissions don't count towards total CO₂e emissions.

large sources, and industrial process emissions for which adequate measurement methods exist. Phase II will begin in 2015, and will expand to include transportation fuels and residential, commercial and industrial fuels not covered in the first phase.

The WCI plan has the broadest scope for targeted sources of the three regional programs. WCI reasons that the more sources covered by the program, the more opportunities there are for reductions, which should improve program efficiency and reduce compliance costs. WCI is also developing "complimentary policies" outside of the cap-and-trade program to further reduce emissions. The most comprehensive policy is to set Low Carbon Fuel Standards (LCFS) for vehicles. This has already been done in California, and Oregon has passed legislation allowing adoption of an LCFS. The plan uses economic assumptions based on no new coal or nuclear energy plants being constructed through 2020.¹⁶⁶

The WCI program also has the broadest definition of regulated emissions. It will cover emissions of carbon dioxide, methane, nitrous oxide, nitrogen tri-fluoride, perfluorocarbons (PFCs), hydrofluorocarbons (HFCs), and sulfur hexafluoride in contrast to the RGGI program that covers only carbon dioxide from the electric power sector. In the first compliance period about fifty percent of GHG emissions will be regulated, and in the second period, beginning in 2015, about ninety percent of the emissions will be regulated. Transportation fuels are the largest source of GHG emissions in the WCI region, although this differs from state to state and province to province.

Although the cap-and-trade program will only be required for sources with an annual potential emissions of 25,000 metric tons of carbon dioxide equivalent (CO₂e) or more, WCI partner jurisdictions will require entities and facilities with annual emission equal to or greater than 10,000 metric tons of CO₂e to report their emissions. California data shows the participation and reporting requirements will cover about 94 percent of the emissions from stationary sources. Although small sources will not be regulated to reduce the costs of administration and to keep the costs of allowances below a projected \$25 through 2020, WCI will most likely regulate small oil and gas sources that can be aggregated by ownership. Decisions are currently being negotiated as to the level of aggregation (field, basin, or jurisdiction) and the reporting threshold (10,000; 25,000; lower; or higher) required to reach the WCI goal to cover a significant portion of emissions with as few facilities and reporting entities as possible.¹⁶⁷ WCI is also harmonizing its

¹⁶⁶ WCI, UPDATED ECONOMIC ANALYSIS OF THE WCI REGIONAL CAP-AND-TRADE PROGRAM (July 2010), available at <http://westernclimateinitiative.org/the-wci-cap-and-trade-program> (last visited Dec.30, 2010).

¹⁶⁷ See WCI issue papers for oil and gas at

<http://westernclimateinitiative.org/component/rempository/Reporting-Committee-Documents/Oil-and-Gas-Workgroup/> (Dec. 20, 2010).

reporting requirements to align with the new EPA GHG reporting requirements that will go into effect in 2011.¹⁶⁸

Each WCI Partner jurisdiction will calculate its own preliminary annual allowance budget based on its projected emissions for covered sources in 2012. Estimates should account for new and shut-down sources as well as voluntary and mandatory emission reductions through 2012. Each jurisdiction should also propose a target rate of decline (RoD) for each year in the compliance period. This preliminary allowance and RoD will be reviewed by the WCI committee for Cap Setting and Allowance Distribution (CSAD), after which the partner jurisdiction may make recommended changes at its discretion. It is ultimately up to each individual partner jurisdiction, working in partnership with other jurisdictions and with input from the CSAD committee, to arrive at its own allowance budget and RoD.¹⁶⁹ WCI recommends that each jurisdiction distribute enough allowances to cover expected emissions for the first year of each compliance period in 2012 and 2015 to ease the transition into the program.¹⁷⁰ There will be an upward adjustment for allowances in 2015, and thereafter, to account for the addition of transportation, residential and commercial fuels to the cap-and-trade program. The western states and Canadian provinces will each have an emissions reduction goal but are free to impose greater reduction requirements.

While the WCI cap-and-trade program encourages consistency among partner jurisdictions, because it is actually a collection of individual state and provincial auctions that are only joined through recognition of other jurisdictions' allowances, it leaves jurisdictions the most discretion to set and distribute allowances, apply offsets, and decide how funds are used of any of the three regional programs. Each WCI Partner jurisdiction will decide how to distribute its allowances to the regulated sources. However, WCI is developing some mechanisms to prevent leakage of emissions from one partner jurisdiction to another or from the WCI region to non-regulated regions. For the first compliance period, WCI recommends a minimum of ten percent of the allowance budget be auctioned, increasing to twenty-five percent in 2020.¹⁷¹ WCI aspires to have a higher percentage of the allowances auctioned, but is concerned over the economic impacts of auctions on industries with competitors not subject to GHG emission controls. WCI encourages partner jurisdictions to identify energy-intensive, trade-exposed (EITE) industries that are particularly vulnerable to outside competition and leakage and suggests that EITEs be given free distribution allowances and

¹⁶⁸ See WCI, FINAL ESSENTIAL REQUIREMENTS FOR MANDATORY REPORTING (July 16, 2009), available at <http://westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/Final-Essential-Requirements-for-Mandatory-Reporting> (last visited Dec. 10, 2010).

¹⁶⁹ See WCI, GUIDANCE FOR DEVELOPING WCI PARTNER JURISDICTION ALLOWANCE BUDGETS, (July 8, 2010), available at <http://westernclimateinitiative.org/wci-committees/cap-setting-a-allowance-distribution-committee> (last visited Dec. 30, 2010).

¹⁷⁰ WCI DESIGN, *supra* note 164, at 8-9.

¹⁷¹ See WCI, FREQUENTLY ASKED QUESTIONS, available at <http://westernclimateinitiative.org/the-wci-cap-and-trade-program/faq> (last visited Dec. 30, 2010).

benchmarked to keep them competitive with outside providers.¹⁷² For electricity providers outside of the WCI region, WCI recommends requiring allowances from the First Jurisdictional Deliverer (FJD) to prevent leakage and unfair competition for electricity providers within WCI.¹⁷³

The money received from auctioned allowances is subject to some general guidance aimed at encouraging GHG reductions, but the Partner jurisdictions have the discretion to use the money as they wish. Once an allowance is obtained, it does not expire, and can be banked. But, if a source has excess emissions it cannot borrow allowances from future distributions. If a covered entity or facility does not have sufficient allowances to cover its emissions at the end of its compliance period, it will be required to surrender three allowances for every excess metric ton of CO₂e in excess of its compliance obligation within three months after the end of the compliance period. There are no other regional penalties in the WCI Design; instead, each jurisdiction is expected to use its authority to enforce compliance. Because some level of harmonization in stringency and enforcement is necessary, WCI strongly recommends that all jurisdictions punish excess emissions by requiring one allowance for each ton of excess plus three additional allowances.¹⁷⁴

On May 8, 2009, the WCI proposed mandatory reporting requirements for facilities subject to the emissions trading program that are more comprehensive than EPA's reporting requirements.¹⁷⁵ Many energy companies that operate in the West oppose this proposal,¹⁷⁶ but Washington has already proposed rulemaking to implement it.¹⁷⁷ WCI also proposes creation of a regional administrative organization to coordinate the regional auction of allowances; tracking emissions and providing public information; reporting on market activity; updates between partner jurisdictions; and review and adoption of protocols and offsets.¹⁷⁸

An important part of the WCI cap-and-trade program involves offsets. Following the tri-regional approach to defining offsets, WCI allows the most generous use of offsets of the three regional programs to achieve GHG reductions, reduce compliance costs and encourage technological innovation. WCI will reward offset certificates to the sponsor of a GHG emissions offset project. A WCI offset certificate is awarded for: "a reduction or removal of one metric ton of carbon dioxide equivalent (tCO₂e). Reductions and removals

¹⁷² WCI DESIGN, *supra* note 164, at 14.

¹⁷³ *Id.* at 24.

¹⁷⁴ WCI DESIGN, *supra* note 164, at DD-37, § 7.2.5.4; *see also* WCI, FREQUENTLY ASKED QUESTIONS, *supra* note 172.

¹⁷⁵ Carolyn Whetzel, *Western Climate Initiative Proposes Mandatory Emissions Reporting Rules*, 40 Env't Rep. (BNA) 1114 (May 15, 2009); *WCI Working With EPA to Resolve Differing GHG Reporting Requirements*, XXI CLEAN AIR REP. 25:27 (Dec. 9, 2010).

¹⁷⁶ *Major Energy Companies Plan Attack On Western Climate Program*, XIX CLEAN AIR REP. (INSIDE EPA) 25:34 (Dec. 11, 2008).

¹⁷⁷ *See* Washington Dept. of Ecology, Chapter 173-441 WAC - Reporting of Emission of Greenhouse Gases, *available at* http://www.ecy.wa.gov/programs/air/globalwarming_RegHaze/GreenHouseGasreporting_rule.html.

¹⁷⁸ WCI DESIGN, *supra* note 164, at 24-25.

must be clearly owned, adhere to recommended protocols, and result from a project located in a qualifying geographic area.”¹⁷⁹ Offsets are achieved through activities that are often referred to as “offset projects.” Offset certificates will be accepted as allowances, subject to limitations (currently recommended as less than 49% of a source’s total emissions), and can be used for compliance purposes or as part of voluntary actions. When used within a cap-and-trade program, offset certificates used for compliance purposes must come from emission sources or sinks not covered by the cap.”¹⁸⁰ Each partner jurisdiction is authorized to issue offset credits for approved GHG reduction projects located in North America. Each partner jurisdiction must accept offset certificates from other partner jurisdictions and may elect to accept offset certificates from outside of North America if it so chooses. This would allow credits from developing countries such as those based on the Clean Development Mechanism of the Kyoto Protocol to be accepted.¹⁸¹

WCI has recommended that offsets be used for no more than forty-nine percent of total emission reductions, though individual Partner jurisdictions may establish a lower percentage limit if they see fit.¹⁸² Before approving offset projects, Partner jurisdictions are responsible for transparently establishing criteria “such that sufficient and appropriate protocol, project and certificate information is disclosed in a timely manner to allow offset system participants and the general public to make decisions with reasonable confidence.”¹⁸³ WCI offsets are based on the same criteria as the tri-regional offsets recommendations: real, additional, permanent, verifiable, and enforceable. Partner jurisdictions are responsible to enforce local offset projects by putting sufficient compliance and enforcement mechanisms in place to compel compliance and verify that offsets actually reduce, remove, or avoid GHGs.¹⁸⁴

Projects within WCI jurisdictions that meet WCI criteria must be recognized by all jurisdictions, regardless of the jurisdiction of origin.¹⁸⁵ Though development of offset projects within WCI jurisdictions is highly encouraged,¹⁸⁶ partner jurisdictions may also accept offset projects throughout the United States, Canada, and Mexico if projects are subject to comparable rigorous oversight, validation, verification, and enforcement actions.¹⁸⁷ Partner jurisdictions may require additional criteria for Clean Development

¹⁷⁹ WCI, OFFSET SYSTEM ESSENTIAL ELEMENTS FINAL RECOMMENDATIONS PAPER (July 2010), available at <http://westernclimateinitiative.org/component/rempository/Offsets-Committee-Documents/Offsets-System-Essential-Elements-Final-Recommendations> (last visited Oct. 21, 2010) [hereinafter WCI OFFSET RECOMMENDATIONS].

¹⁸⁰ WCI DESIGN, *supra* note 164, at DD-27, § 5.3; § 8.

¹⁸¹ WCI OFFSET RECOMMENDATIONS, *supra* note 207, at § 3.2.3.

¹⁸² WCI, DESIGN RECOMMENDATIONS FOR WCI REGIONAL CAP-AND-TRADE PROGRAM (2008) § 9.2, at 10, available at <http://www.westernclimateinitiative.org/document-archives/wci-design-recommendations> (last visited Dec. 30, 2010) [hereinafter WCI DESIGN RECOMMENDATIONS].

¹⁸³ WCI DESIGN, *supra* note 164, at DD-43, §8.

¹⁸⁴ *Id.*

¹⁸⁵ WCI OFFSET RECOMMENDATIONS, *supra* note 180 at 5, § 3.2.3.1. Offsets not meeting the WCI criteria will not be accepted for compliance purposes.

¹⁸⁶ WCI DESIGN RECOMMENDATIONS, *supra* note 183, at § 9.3, at 10.

¹⁸⁷ *Id.* at § 9.7, at 11.

Mechanism projects to guarantee they meet WCI's offset project standards.¹⁸⁸ WCI is currently working on Offset Process Draft Recommendations that will detail more specific requirements for registration, validation, monitoring, quantification, reporting, verification, certification, and issuance of offsets.¹⁸⁹

In response to the Design Recommendations' call for further review of priority offset protocols, WCI has begun protocol development to ease region-wide use of three types of offset projects: Agriculture (soil sequestration and manure management); Forestry (afforestation/reforestation, forest management, forest preservation/conservation, forest products); and waste management (landfill gas and wastewater management).¹⁹⁰

The WCI's offset program does not currently include provisions for CCS technology, but it does flag CCS as a possibility in the future. For example, section 8.2 of the Design Recommendations mandates that each Partner jurisdiction agree to dedicate a portion of the jurisdiction's allowance budget to region-wide research, development, demonstrations, and deployment of CCS technology.¹⁹¹ This provision also "[p]romot[es] emission reductions and sequestration in agriculture, forestry and other uncapped sources."¹⁹² The explanation for the "permanent" requirement for offsets also mentions sequestration of carbon, although it does not differentiate between geological or biological sequestration. In order for sequestration to qualify for offset status, it should achieve the same atmospheric effect as non-sequestration projects, which is based on the international standard developed by United Nations Framework Convention on Climate Change (currently 100 years).¹⁹³ However, the Offset Protocol document does not specifically address or mention CCS or related technology.

While WCI is progressing in documenting its program design and developing policies to compliment its cap-and-trade program, a review of how proposals have developed through the collaborative process of WCI shows that definitive regional control or specific limitations for partner jurisdictions have been softened or removed from final documents. WCI seems to be moving away from policies that could be construed as centralizing control in WCI. For example, the emphasis on a region-wide cap set forth in the Design Recommendations changed to emphasize only individual jurisdictional caps in the Final Design document. The Design Recommendations set forth guidance for WCI to apportion allowances based on partner jurisdiction emissions limits.¹⁹⁴ The Final Design document makes no

¹⁸⁸ *Id.* at § 9.8, at 11.

¹⁸⁹ WCI DESIGN, *supra* note 164, at DD-40 § 8.

¹⁹⁰ WCI, OFFSET PROTOCOL REVIEW REPORT (April 2010), available at <http://www.westernclimateinitiative.org/component/rempository/Offsets-Committee-Documents/Offset-Criteria-Draft-Recommendations/> (last visited Dec. 30, 2010).

¹⁹¹ WCI DESIGN RECOMMENDATIONS, *supra* note 183, at § 8.2, at 7.

¹⁹² *Id.*

¹⁹³ WCI DESIGN, *supra* note 164, at DD-42-43, § 8.

¹⁹⁴ WCI DESIGN RECOMMENDATIONS, *supra* note 183, at §§ 6.2 and 7.

mention of regional apportionment, and instead emphasizes only regional consultations: "Although developed in a regionally-coordinated manner through these guidelines, each Partner jurisdiction will determine and adopt its own budget. Each Partner jurisdiction will also determine how allowances within its budget will be distributed (e.g., to address competitiveness and leakage issues)."¹⁹⁵ The regional administrative organization described in the Design Recommendations is not mentioned in the Final Design and seems to be replaced by a Program Authority in each partner jurisdiction who will administer the program based on recommended standards and discretionary avenues of regional coordination.¹⁹⁶

For the WCI program to become a reality, member states and provinces must enact the necessary implementation legislation. In the political climate after 2010 mid-term elections, there is great uncertainty as to whether the disparate interests of the western states can lead to a uniform regional approach.¹⁹⁷ The governors of Oregon, California, and Washington support the WCI cap-and-trade program, but legislatures in Washington, Oregon, New Mexico and Utah have sought to delay implementation of the WCI program and require more legislative involvement. Utah, Arizona and Montana postponed considering legislation in 2009, and Arizona's new governor signed an executive order that barred Arizona's participation in WCI's cap-and-trade program.¹⁹⁸ California's 2006 global warming law, A.B.32, which calls for a reduction of GHG emissions to 1990 levels by 2020 (more stringent than WCI) is also politically vulnerable. California is being sued by environmentalists who claim California's regulations are not as stringent as the law requires,¹⁹⁹ while industry proponents managed to put the law on a ballot initiative in the November election which could have essentially killed the bill.²⁰⁰ While the A.B. 32 ballot initiative was defeated, another ballot initiative (Proposition 26) will likely be used by opponents to challenge A.B. 32 in court.²⁰¹ As of early 2011 California is only WCI member state that is moving to implement a cap-and-trade program. The Canadian provinces of

¹⁹⁵ WCI, GUIDANCE FOR DEVELOPING WCI PARTNER JURISDICTION ALLOWANCE BUDGETS, at 2 (July 8, 2010). *See also* § 3.

¹⁹⁶ Compare WCI DESIGN RECOMMENDATIONS, *supra* note 183, at § 13 and WCI DESIGN (final), *supra* note 164, at § 7.

¹⁹⁷ See, e.g., Nora Macaluso, *Midwest Climate Accord Languishes, Leaving States to Take Actions Alone*. 41 Env't Rep. Cur. Dev. (BNA) 2122 (Sept. 24, 2010).

¹⁹⁸ HOLLAND & HART, UPDATE ON WESTERN CLIMATE INITIATIVE LEGISLATION (Mar. 17, 2009); William H. Carlile, *State Decides Against Implementing Climate Proposal, Cites Economic Lag*, 41 Env't Rep. Cur. Dev. (BNA) 390 (Feb. 19, 2010).

¹⁹⁹ *Activists Charge California Climate Rules May Violate State Law*, XIX CLEAN AIR REP. (Inside EPA) 17:9 (Aug. 21, 2008).

²⁰⁰ See John Hoeffel & Margot Roosevelt, *California Voters Turning Against Prop. 19 and Prop. 23, Poll Shows*, L.A. TIMES (Oct. 21, 2010), available at <http://www.latimes.com/news/local/la-me-1021-prop-poll-20101021,0,1066812.story>.

²⁰¹ See Margot Roosevelt, *Lawyers, Lobbyists, Politicians Scramble to Determine Impact of Prop. 26*, LOS ANGELES TIMES (Nov. 14, 2010), available at <http://www.latimes.com/news/local/la-me-prop26-impact-20101115,0,2819277.full.story> (last visited Nov. 22, 2010).

Ontario, British Columbia and Quebec also may approve a cap-and-trade program or a functional equivalent to begin in 2012.²⁰²

§ 3. State Carbon Capture and Sequestration Efforts

§ 3(a). State Property Law and CCS

In the United States the use of under ground reservoirs and the associated pore space for storage is considered to belong to the surface owner unless they have been legally transferred to another person or entity.²⁰³ However, those with mineral rights have the right to reasonable use of pore spaces as needed to capture minerals.²⁰⁴ State law generally governs property issues except on federal lands. State laws vary, and much of the law is based on case law that has developed from conflicts over oil and gas contracts or lease provisions. The generally accepted interpretation for oil and gas leases is that any property right not explicitly conveyed is retained by the grantor, usually the surface owner.²⁰⁵ For this reason, the decisions are often based on the language of the documents in dispute. For example in *Mapco v. Carter*, a Texas district court ruled the mineral owner's rights prevailed over the surface owner's rights because the natural gas was being stored in a cavern formed only by removing the mineral in question—salt—and the lease reserved all minerals to the mineral owner.²⁰⁶ Almost all other cases have held that the pore space belongs to the surface owner.²⁰⁷ Most states follow “the American Rule” that after subsurface minerals have been removed, the surface owner owns the depleted space.²⁰⁸ A minority of states follow “the English Rule,” such as

²⁰² *California Sees New Mexico Cap & Trade Rules As Clearing Way For WCI*, XXI CLEAN AIR REP. (Inside EPA) 15:30 (July 22, 2010); *Inaction by Canadian Provinces Casts More Doubt Over Launch of WCI*, XXII CLEAN AIR REP. 3:26 (Feb. 3, 2011)..

²⁰³ The Interstate Oil and Gas Compact Commission, *Storage of Carbon Dioxide in Geologic Structures, A Legal and Regulatory Guide for States and Provinces* 11 (2007) hereinafter IOGCC].

²⁰⁴ See Ian J. Duncan, Scott Anderson, and Jean-Philippe Nicot, *Pore Space Ownership for CO₂ Sequestration in the U.S.*, 1 ENERGY PROCEDIA 4427, 4429-30 (2009).

²⁰⁵ *Id.* at 4430; Adam S. Vann, Legislative Attorney, American Law Division of the Congressional Research Service, Carbon Capture and Sequestration Legislation, 7, testimony before the Committee on Energy and Natural Resources, April 20, 2010, available at http://energy.senate.gov/public/index.cfm?FuseAction=Hearings.Testimony&Hearing_ID=f7492203-de28-8890-5335-601db031dfed&Witness_ID=6b9a9250-ea7c-4e60-9220-8d1b88c7870f (last visited Nov. 22, 2010).

²⁰⁶ 808 S.W.2d 262 (Tex. App.—Beaumont 1991), *rev'd in part*, 817 S.W.2d 686 (Tex. 1991).

²⁰⁷ *But c.f.* Central Ky. Natural Gas Co. v. Smallwood, 252 S.W.2d 866, 868 (Ky. 1952). Two recent analyses of cases holding in favor of mineral owners distinguish these holdings by the specific facts of the case, arguing that unless lease language or court interpretations of surrounding circumstances provide a reason to give ownership rights to a mineral owner, case law in the U.S. upholds pore space as property belonging to the surface owner. *See generally* Duncan, *supra* note 205; *see also* Vann, *supra* note 233 at 5-6. These cases are also discussed in a paper prepared by David Cooney found in the IOGCC report, *supra* note 231, at 14-22.

²⁰⁸ IOGCC *supra* note 231, at 116.

Kentucky and Texas, which allows the mineral owner to continue to own the pore space after all minerals have been extracted.²⁰⁹ This approach creates uncertainty because it is not easy to determine when the reservoir has been depleted. The age of the case law on this subject, its focus on oil and gas law, and its fact dependency make the precedent of marginal value, and several authors have recently called the majority/minority interpretation into question.²¹⁰ Case law does demonstrate the need for certainty in this field if large-scale CCS development is to occur. It would be best if ownership rights were clarified through legislation to avoid the need for CCS operators to obtain approval (with the associated costs and potential for litigation) from the holders of all potential property interests on a case-by-case basis.

Bills are pending in both the House and the Senate that would designate pore space as belonging to the surface owner for federal lands.²¹¹ Some states have also begun the process of specifying pore space ownership through legislation. In Wyoming pore spaces were declared to be the property of the surface owner.²¹² This legislation is discussed *infra* § 4(r). In Montana H.B. 498 became law on May 6, 2009. It upholds common law interpretations of property rights and provides that, unless otherwise discernable from deeds or severance documents, ownership of storage reservoirs will be presumed to attach to surface ownership.²¹³ However, mineral owners still have the right to drill around or through pore space owned by the surface owner as long as they meet certain state safety requirements.²¹⁴ After completion of the project and 15 years of monitoring, the CCS facility owner may transfer ownership and liability to the state if specific conditions are met.²¹⁵ Other states seem to follow the recommendation of IOGCC and designate the CCS facility owner as the owner of any CO₂ injected for the purpose of sequestration without explicitly designating pore space ownership.²¹⁶

Because of the variation in the details of state CCS regulatory programs, there have been attempts to bring some consistency to the process. In 2007, IOGCC issued

²⁰⁹ Elizabeth J. Wilson & Mark A. de Figueiredo, *Geologic Carbon Dioxide Sequestration: An Analysis of Subsurface Property Law*, 36 ENVTL. L. REP. (ELI) 10114, 10117 (2006). Williams & Meyers present the counter-argument that mineral owners should have property rights to pore space, at least in relation to storage of natural gas. *See* Williams & Meyers, 1-2 Oil & Gas Law § 222 (Conclusions) (Lexis 2010).

²¹⁰ *See generally* Duncan *et al.*, *supra* note 232.

²¹¹ A Bill to Amend the Energy Policy Act of 2005 to Clarify Policies Regarding Ownership of Pore Space, S. 1856, H.R. 6077, 111th Cong. (2009-10).

²¹² WYO. STAT. ANN. § 34-1-152 (H.B. 0089) (2008).

²¹³ Montana S.B. 0498 § 1(3) (2009).

²¹⁴ Montana S.B. 0498 § 1(1)(b) (2009). Most states have a similar provision, allowing mineral rights owners access around or through carbon sequestration reservoirs subject to specific approvals and safety requirements.

²¹⁵ Montana S.B. 0498 §§ 6, 7 (2009).

²¹⁶ *See, e.g.*, 27A OKL. ST. ANN. § 3-5-105 (West 2010); TEX. NAT. RES. CODE ANN. T.3, Subpt. D, Ch. 120 (Vernon 2010). In Oklahoma, mineral rights are considered to be incorporeal, meaning they entail the right to try to capture the minerals, but the minerals themselves do not belong to the party with mineral rights until they are captured. Texas views mineral rights as property rights. However, ownership of the pore space does not seem to be spelled out in either states' legislation, and as discussed above, common law interpretations leave some confusion about ownership rights.

a model program based on existing oil and gas regulatory programs that includes model statutes and regulations to help states develop legal mechanisms encouraging the use of CCS. The IOGCC guidance covers both property law and liability issues.²¹⁷ IOGCC believes it is essential for the storage project to be controlled by the operator of the sequestration project regardless of who owns the pore space. This necessitates acquisition of the necessary property interests from the landowner and possibly mineral owners.

As states develop geological sequestration programs they will also face constitutionally based challenges concerning the extent to which an owner of the surface or subsurface estate can control areas deep below ground. If subsurface pore space is used for sequestration by state governments, will surface or subsurface owners have a cause of action for a physical or regulatory taking under the Fifth Amendment for which compensation would need to be paid? These issues have been covered in a seminal article by Professors Klass and Wilson and will only be lightly treated in this article.²¹⁸

Until the advent of air travel, ownership of land extended to the sky and to the center of the earth. But in 1946 the U.S. Supreme Court declared the air to be a public highway.²¹⁹ No similar decision has been made concerning subsurface rights, which have been subject to an extensive body of property laws designed to protect owners of land.²²⁰ In 1982 the Supreme Court made it clear that the government's physical occupation of land is a taking for which compensation is required.²²¹ However, the Court has never ruled whether land far beneath the surface belongs to those holding property interests in the surface land, although a significant body of relevant state law has developed regarding oil and gas development, underground waste injection, and natural gas storage.²²²

Natural gas storage was the subject of congressional action in the Natural Gas Act that implicitly recognizes a property interest in the use of land for subsurface storage of natural gas, and this property right is subject to the power of eminent domain.²²³ The law of damages for adverse impacts on land from oil and gas secondary recovery is usually based on state statutes governing the petroleum industry, but the absolute ownership doctrine (defining land ownership as extending to the periphery of the universe) is usually rejected.²²⁴ Waste injection cases in which surface owners seek recovery for damages to their property caused

²¹⁷ IOGCC *supra* note 231, at 23. Another model rule is found in Victor B. Flatt, *Paving the Legal Path for Carbon Sequestration from Coal*, 19 DUKE ENVTL. L. & POL'Y FORUM 211, 242 (2009).

²¹⁸ Alexandra B. Klass & Elizabeth J. Wilson, *Climate Change, Carbon Sequestration, and Property Rights*, 2010 U. ILL. L. REV. 363 (2010) [hereinafter Klass & Wilson, *Property Rights*].

²¹⁹ United States v. Causby, 328 U.S. 256, 260-61 (1946).

²²⁰ Klass & Wilson, *Property Rights*, *supra* note 246, at 389.

²²¹ Loretto v. Teleprompter Manhattan CATV Corp., 458 U.S. 419 (1982).

²²² See Klass & Wilson, *Property Rights*, *supra* note 246, at 391; Duncan, *supra* note 232, at 4428-31.

²²³ 15 U.S.C. § 717f(h) (Lexis 2010); Klass & Wilson, *supra* note 246, at 401.

²²⁴ Klass & Wilson, *Property Rights*, *supra* note 246, at 397.

by deep well injection usually require plaintiffs to prove harm to actual use of the subsurface.²²⁵ This led Professors Klass and Wilson to conclude that the law is not clear, and courts that face carbon sequestration takings issues have options ranging from recognizing property rights in pore space only when actual harm to the pore space itself or ongoing economic uses occurs, to recognizing a property interest in subsurface pore space regardless of use or reasonably foreseeable use. However, even if an absolute right to the pore space is recognized, the amount of compensation provided in such cases will determine the importance of an absolute right.²²⁶ Professor John Sprankling argues that private property rights to land should not extend more than 1,000 feet down, and pore space below that depth should be publicly owned.²²⁷ Sprankling's suggested cutoff depth is probably unrealistic given the depth at which oil and gas and other mineral industries now work, sometimes far in excess of 1,000 feet. A better approach, according to Professors Klass and Wilson, is to pass legislation authorizing deep subsurface carbon sequestration that terminates private subsurface property interests except for uses already being made or uses that are based on reasonable investment-backed expectations.²²⁸

A *per se* regulatory taking occurs if a landowner is deprived of all reasonable, beneficial use, even in the absence of any physical taking. However, based on *Lucas v. South Carolina Coastal Council*, even if all economic use of the property is denied by a regulation, it may not be a *per se* regulatory taking if the restriction is based on the law of nuisance.²²⁹ This holding makes it even more difficult to prove a regulatory taking occurred.²³⁰ If a property has some economic value remaining, the balancing test found in *Penn Central Transportation Co. v. New York City* will be used to determine whether a regulatory taking has occurred.²³¹ The application of the balancing tests in a carbon sequestration case will be affected by whether courts consider the pore space to be an independent property right that can be considered separately from the use of the entire property. Even if a taking is established, a property owner is required to show its losses in order to be eligible for federal economic assistance.²³² For most properties this mandate will limit potential claimants.

Additional problems are created if the subsurface estate is held by more than one entity. For example, ownership issues have arisen in coalbed methane (CBM) controversies where the issue is whether the coal owner or the natural gas owner has the right to extract CBM. The American Rule is that CBM belongs to the natural

²²⁵ *Id.* at 398.

²²⁶ *Id.* at 404.

²²⁷ John G. Sprankling, *Owning the Center of the Earth*, 55 UCLA L. REV. 979, 982 (2008).

²²⁸ Klass & Wilson, *Property Rights*, *supra* note 246, at 408.

²²⁹ 505 U.S. 1003, 1028-29 (1992).

²³⁰ Klass & Wilson, *Property Rights*, *supra* note 246, at 415.

²³¹ 438 U.S. 104 (1978).

²³² Klass & Wilson, *Property Rights*, *supra* note 246, at 418.

gas owner, not the coal owner.²³³ If the title to the pore space is held by the surface owner, and coal underlying a tract of land has been severed from the other mineral interests, what are the rights of those owning part of the subsurface estate? One effort to deal with split estate issues is found in the Wyoming Surface Owner Accommodation Act that provides protection for surface owners from surface activities of the subsurface owners.²³⁴ A similar approach may be needed to protect subsurface interests if the surface owner allows geological sequestration to occur.

§ 3(b). State CCS Permits

In December of 2010, EPA finalized federal rules for underground injection of CO₂ for purposes of geological storage (UIC Rules).²³⁵ With the release of the EPA's final rule covering CO₂ injection underground for storage purposes, there is both more surety for CCS projects and less discretion for state control of CCS. Operators of all CCS projects will now need an operating permit from either the state where the project is located or from EPA. The permitting authority will require detailed engineering and geological data that demonstrates the suitability of the site for long-term carbon sequestration. The size of the project area that will be monitored and reviewed will also be defined by the permitting authority. The UIC Rules are promulgated under the Safe Drinking Water Act (SDWA) and establish a new category of injection wells, Class VI, that covers underground injection for the purpose of geologic storage of CO₂. The UIC Rules require owners or operators of Class VI wells to 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 inject into suitable formations. Class VI well owners or operators must also identify additional confining zones, if required by the Director, to increase protection for underground sources of drinking water. Owners or operators must submit, with their permit applications, a series of comprehensive site-specific plans: An area of review (AoR) and corrective action plan, a monitoring and testing plan, an injection well plugging plan, a post injection site care (PISC) and site closure plan, and an emergency and remedial response plan. The requirement for a comprehensive series of site-specific plans is new to the UIC program.²³⁶

Under section 1421(b), the UIC Rules mandate that EPA develop minimum federal requirements that a state must meet to achieve UIC primary enforcement responsibility, or primacy, to ensure protection of underground sources of drinking water (USDWs). If states want to implement the UIC program, they must apply to

²³³ Allan Ingelson & Lincoln Mitchell, *CBM Legal Issues—The Western U.S.A. and Canada*, 47 ROCKY MTN. MIN. L. FOUND. J. 19, 31 (2010).

²³⁴ WYO. STAT. ANN. §§ 30-5-401 to 30-5-410.

²³⁵ Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO₂) Geologic Sequestration (GS) Wells, 75 Fed. Reg. 77230 (Dec. 10, 2010) (to be codified at 40 CFR Parts 124, 144, 145, 146, and 147) [hereinafter UIC Rules].

²³⁶ *Id.* at 77293.

EPA for primacy approval. In the primacy application, states must demonstrate: (1) state jurisdiction over under-ground 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 CFR 145.13. EPA will directly implement the UIC program for states that do not apply for primacy and for states that only have primacy for part of the UIC program.²³⁷ EPA will allow states to achieve independent primacy for Class VI wells, under § 145.1(i) of the final rule, and will accept applications from states for independent primacy under section 1422 of the SDWA for managing UIC storage projects under Class VI. EPA's willingness to accept independent primacy applications for Class VI wells applies only to Class VI well primacy and does not apply to any other well class under SDWA section 1422 (i.e., I, III, IV, and V). States will have 270 days following EPA's final promulgation of the geologic storage rule on September 6, 2011 to submit a complete primacy application that meets the requirements of §§ 145.22 or 145.32.

Section 145.23(f)(1) requires states with primacy to include a schedule for issuing Class VI permits for wells within the state that require them within two years after receiving program approval from EPA, and § 145.23(f)(2) requires states to include their permitting priorities, as well as the number of permits to be issued during the first two years of program operation. State or EPA directors must also submit a plan to notify existing owners/operators of Class I wells that have become storage sites or Class V experimental wells that will now be used for storage that they must apply for a Class VI permit to either the state or EPA permitting authority within one year of December 10, 2011.

Section 146.82(a)(2) requires the owner or operator of a CCS operation to identify all state, tribal, and territorial boundaries within the AoR. Based on the information provided to the state or EPA Director during the initiation of the permit application, the Director, pursuant to requirements at § 146.82(b), must provide written notification to all states, tribes, and territories in the AoR to inform them of the permit application and to afford them an opportunity to be involved in any relevant activities (e.g., development of the emergency and remedial response plan (§ 146.94)). Owners or operators must periodically reevaluate the AoR to incorporate monitoring and operational data and verify that the CO₂ is moving as predicted within the subsurface. The AoR is defined in the final rule as, "the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected CO₂ stream and displaced fluids and is based on available site characterization, monitoring, and operational data as set forth in § 146.84." EPA is developing guidance on AoR and corrective action to support AoR delineation (i.e., including regions of the CO₂ plume and pressure front). Under the proposed approach, AoR

²³⁷ *Id.* at 77241.

reevaluation would occur at a minimum of every 10 years during CO₂ injection, or when monitoring data and modeling predictions differ significantly. Periodic AoR reevaluation is an integral component of this approach. EPA believes that the AoR reevaluation is an efficient use of resources and notes that if the CO₂ plume and pressure front are moving as predicted, the burden of the AoR reevaluation requirement will be minimal.

The UIC Rules, at § 146.91(e), also require that all 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 as well as those in states where EPA implements the Class VI program, pursuant to § 147.1. All Directors will have access to the data through the EPA electronic data system.

The information submitted as a demonstration, to the Director, must be in the appropriate format and level of detail necessary to support permitting and project-specific decisions by the Director to ensure USDW protection. The final decision regarding the appropriateness and acceptability of all owner or operator submissions rests with the Director. Owners or operators must submit, pursuant to the requirements at § 146.91(e), information to the Director to support Class VI permit applications (this information is enumerated at § 146.82). This information includes site characterization information on the stratigraphy, geologic structure, and hydrogeologic properties of the site; a demonstration that the applicant has met financial responsibility requirements; proposed construction, operating, and testing procedures; and AoR/corrective action, testing and monitoring, well plugging, PISC and site closure, and emergency and remedial response plans.

Class VI well owners or operators must retain data collected to support permit applications and data on the CO₂ stream until 10 years after site closure. Owners or operators must retain monitoring data collected under the testing and monitoring requirements at § 146.90(b-i) for 10 years after it is collected. The rule allows the Director authority to require the owner or operator to retain specific operational monitoring data for a longer duration of time (§ 146.91(f)(5)). Well plugging reports, PISC data, and site closure reports must be kept for 10 years after site closure (§§ 146.92(d), 146.93(f), and 146.93(h))

Section 146.92 requires owners or operators of Class VI wells to plug injection and monitoring wells in a manner that protects USDWs. The final rule, at § 146.93, also contains tailored 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 CO₂ 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 submitted with their permit application (§ 146.92(b)). The approved injection well plugging plan will be incorporated into the Class VI permit. The Agency is developing guidance that describes the contents of the project plans required in the GS rule, including the injection well plugging plan.

Upon cessation of injection, the UIC Rules require that 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 (§ 146.93(a)(3)). The Agency is developing guidance that describes the content of the project plans required in the GS rule, including the PISC and site closure plan. EPA retains the proposed default 50-year PISC timeframe. However, the final rule affords flexibility regarding the duration of the PISC timeframe by: (1) allowing the Director discretion to shorten or lengthen the PISC timeframe during the PISC period based on site-specific data, pursuant to requirements at § 146.93(b); and, (2) affording the Director discretion to approve a Class VI well owner or operator to demonstrate, based on substantial data during the permitting process, that an alternative PISC timeframe is appropriate if it ensures non-endangerment of USDWs pursuant to requirements at § 146.93(c). Section 146.93(c) provides the Director discretion to approve a demonstration during the permitting process (per requirements at § 146.82(a)(18)) that an alternative PISC timeframe, other than the 50-year default, is appropriate.

Following a determination under § 146.93 that the site no longer poses a risk of endangerment to USDWs, the Director would approve site closure and the owner or operator would be required to properly close site operations. These site closure requirements are 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 CO₂. Site closure would proceed according to the approved PISC and site closure plan (§ 146.93(d) through (h)).

The rule also finalizes regulations at § 146.85 that require owners or operators to demonstrate and maintain financial responsibility, as approved by the Director, for performing corrective action on wells in the AoR, injection well plugging, PISC and site closure, and emergency and remedial response. 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 section 1423 of 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, or under section 1423 of the SDWA for violating § 144.12, such as where the owner or operator provided erroneous data to support approval of site closure. Additionally, an owner or operator may always be subject to an order the EPA Administrator deems necessary to protect the health of persons under section 1431 of the SDWA after site closure if there is fluid migration that causes or threatens imminent and substantial endangerment to a USDW.

The finalization of these EPA regulations will impact the state CCS controls discussed in this paper. EPA is currently tracking regulatory efforts in eighteen

states: Colorado, Illinois, Kansas, Kentucky, Louisiana, Michigan, Mississippi, Montana, New Mexico, New York, North Dakota, Oklahoma, Pennsylvania, Texas, Utah, Washington, West Virginia, and Wyoming. EPA is considering this information as it develops guidance on the primacy application and approval process for Class VI wells. States have taken considerable action to regulate, promote, and secure CCS projects throughout the United States.

West Virginia enacted H.B. 2860 on May 4, 2009, to regulate CCS. On the same day the West Virginia Department of Environmental Protection issued an underground injection permit to allow the Appalachian Power Company to inject up to 165,000 metric tons of carbon dioxide over a four to five year period from its Mountaineer Plant. The facilities that are permitted must comply with the Clean Water Act and meet West Virginia's new requirements for site monitoring, notice if sequestered carbon dioxide is released, guidelines for terminating a CCS project, and post-closure. Civil penalties up to \$25,000 per day are established for violations of these state requirements. This project will only sequester a small portion of the plant's CO₂ emissions, but it is the first CCS project at an existing facility.²³⁸

Kansas enacted legislation in March 2007 that directs the Kansas Corporation Commission to develop CCS rules.²³⁹ The Kansas rules require well construction standards and a storage permit, but no underground injection permit is required. Kansas law also creates a fund to pay for the costs of regulation, remediation and monitoring of CCS activities.²⁴⁰

As more states develop regulatory programs, various issues need to be resolved. What concentration of CO₂ will trigger the applicability of CCS legislation? How much contamination should be allowed in the injected waste stream? How are CO₂ concentrations to be monitored and enforced? How is the appropriateness of the site to be demonstrated? What control over the use of models for risk assessment, site integrity, plume movement, etc. will be given to the permitting authority? What baseline data will be required, and who will be responsible for developing it? Will health impacts on drinking water be regulated and will other health impacts be regulated? Are ecosystem impacts, including impacts on wildlife to be covered? How long must the CO₂ be sequestered? How are the site selection and design of the facility going to achieve that goal? What remedies are available to the state if the CCS facility leaks outside the reservoir or into the atmosphere? How is the reservoir defined so as to determine when CO₂ is not being confined? How is the geologic integrity of the facility to be monitored and what are the remedies if there is a failure of the containment, including triggering earthquakes, subsidence or other breaches of the physical integrity of the facility? What other monitoring will be required? What authority will the state have to determine the need for mitigation

²³⁸ Bebe Raupe. *Officials Issue State's First Permit to Allow Carbon Dioxide Sequestration*, 40 ENV'T REP. (BNA) 1091 (May 8, 2009).

²³⁹ KANSAS STAT. ANN. §§ 55-1636 *et seq.* (West 2010); H.B. 2419 (Mar. 2007).

²⁴⁰ The Washington and Kansas approaches are discussed in Pollak & Wilson, *supra* note 263.

or remediation of the site, and what authority will it have over implementation of such measures? How long after the injection ends will the operator remain liable? What must the operator show in order to have the state assume long-term responsibility for the site? Under what circumstances can the liability of the operator be revisited? As state permit programs proliferate, an important issue will be whether federal laws will be enacted that preempt or restrict state permit requirements.²⁴¹

§ 3(c). State Monitoring, Closure, and Post-closure Requirements

After an injection activities cease a well should be plugged in a manner required by state or federal regulations. The IOGCC has recommended a two-stage process with a Closure Period and a Post-Closure Period. The Closure Period begins when the injection well is plugged and continues for a specified time. The IOGCC recommends ten years.²⁴² During the Closure Period the operator would be responsible for site monitoring and for maintaining a facility bond to assure that resources are available to meet closure obligations. At the end of this defined period the operator must demonstrate the well is not releasing carbon dioxide outside the boundaries of the reservoir or into the atmosphere and the operation is in compliance with applicable federal and state law. If the state agrees, it would assume the long-term stewardship obligation and the operator's bond would be released. It would be useful to create an industry-funded trust fund that is administered by the state to assure that money is available to cover the costs of post-closure state management including monitoring, verification and any remediation actions that may be required in the future. The money for the trust fund could be generated from a per-ton charge on the carbon dioxide at the time it is injected.²⁴³

§ 3(d). Renewable Portfolio Requirements

The failure of the federal government to develop a sustainable electrical energy policy has led to state efforts that encourage and discourage the use of fossil fuel to generate electricity. States have created renewable portfolio standards, trust funds to encourage renewable energy, and net metering requirements to promote decentralized, distributed energy.²⁴⁴ On the other hand, some states allow stand-by service charges on dispersed generators, charge exit fees for customers that depart from centralized electric power providers, and resist transmission infrastructure

²⁴¹ For example, the Energy Policy Act of 2005 § 311, 15 U.S.C. § 717b(e)(1), preempted local and state control over the siting of liquefied natural gas facilities. The law was upheld in *AES Sparrows Point LNG, L.L.C. v. Smith*, 470 F. Supp.2d 586, 589 (D. Md. 2007). This could be a model for CCS legislation.

²⁴² IOGCC, *supra* note 231, at 11.

²⁴³ *Id.*

²⁴⁴ Steven Ferry, *Power Future*, 15 DUKE ENVT L. & POL'Y FOR. 261, 284 (2005).

upgrades that protect existing fossil fuel generators from competition from new technologies or out-of-state electricity providers.²⁴⁵

Perhaps the most important of these state actions is the spread of state renewable portfolio standards (RPS) that require electric utilities to meet a specified percentage of their electricity sales using renewable resources. In 2010, thirty-six states and the District of Columbia have RPS.²⁴⁶ However there is little consistency among the state RPS statutes. Iowa, in 1991, was the first state to enact an RPS. Iowa as well as most states that subsequently enacted RPS, specified a percentage of electricity that had to be generated from renewable sources. The required standards range from 0.2 to 33 percent.²⁴⁷ New York, for example, requires 25% of the state's power to be generated from renewable sources by 2013; California requires at least 20% by 2017;²⁴⁸ the District of Columbia requires 20% by 2020;²⁴⁹ and Colorado requires 30% by 2020.²⁵⁰ The renewable percentage and time for compliance of the mandates do not accurately describe the efforts of the state legislatures, however, because the requirements can range from strict mandates to voluntary.²⁵¹ Moreover, credit multipliers are used by many states to provide additional subsidies to certain types of renewable resources or to benefit renewable power generated within the state.²⁵²

Some states require a minimum percentage of the power sold in the state to come from renewable energy, which is known as a "bundled" approach. In 2010, only California, Arizona, Illinois, and Iowa are considered to be bundled states. In California, utilities must submit a procurement plan for renewable purchases to the California Public Utilities Commission (CPUC). After CPUC approval, the utilities must contract for the purchase of renewable electricity and have the CPUC approve the contracts.²⁵³ Other states with RPS use an "unbundled" approach that allows utilities to purchase renewable energy credits (RECs) from electric power generators located anywhere in the country to meet RPS mandates. RECs are tradable commodities, with each REC typically representing one megawatt-hour of electricity generated from a renewable source.²⁵⁴ But the time allowed for the RECs

²⁴⁵ *Id.* at 284, 278.

²⁴⁶ Lincoln L. Davies, *Power Forward: The Argument for a National RPS*, 42 CONN. L. REV. 1339 (2010).

²⁴⁷ For a comprehensive summary of state actions, see <http://www.dsireusa.org/> (last visited Nov. 4, 2010); see also Ari Natter, *Coalition Urges 'Rapid Enactment' of Bill to Establish Renewable Electricity Standard*, 40 Env't Rep. (BNA) 688 (Mar. 3, 2009).

²⁴⁸ Paul A. O'Hop, *Growing Green Power*, LEGAL TIMES, May 16, 2005, at 39.

²⁴⁹ Mary Cheh, *Greening the Capital City with a Sustainable Energy Utility*, 40 TRENDS 10 (ABA Jan./Feb. 2009).

²⁵⁰ *Colorado Gas Bill Touted As Model For States to Meet EPA Air Rules*, XXVII ENVTL. POL'Y ALERT (Inside EPA) 7:38 (Apr. 7, 2010).

²⁵¹ Compare HAW. REV. STAT. ANN. § 269-92(A)(4) (West 2010) with UTAH CODE ANN. §§ 54-17-602(1)(a) & 54-7-12(c)(2) (West 2010).

²⁵² See Davies, *supra* note 274, at 1399 (App. B) & 1401 (App. D).

²⁵³ Tom Mounteer, *To Bundle or Not Bundle*, 40 Env't L. Rep., News & Analysis (ELI) 10119 (Feb. 2010).

²⁵⁴ *Id.*

to be used range from one year to unlimited.²⁵⁵ The variability of the state RPS programs is a constraint on the development of a viable trading system.²⁵⁶

States, such as California, with renewable portfolio requirements are also discovering the construction of facilities needed to meet RPS will not be met by the imposed deadlines.²⁵⁷ Moreover RPS may not produce carbon reductions beyond those that could be achieved with a cap-and-trade system. It has been argued that cap-and-trade will achieve the same objective as RPS at a lower cost and will preserve the freedom of the regulated entities to decide how to best comply.²⁵⁸ But cap-and-trade faces its own implementation hurdles. Federal efforts at RPS include President Obama's call for twenty-five percent of the nation's electric power to be generated from renewables by 2025. The Waxman-Markey Bill includes a federal renewable portfolio and electricity savings standard starting at 6% in 2012 and increasing to 20% in 2020. The Waxman-Markey Bill limits the use of energy efficiency measures to meet the mandate to 40% of the combined renewable electricity and electricity savings requirement.²⁵⁹ However, as discussed in § 2, *supra*, federal efforts to enact either cap-and-trade or RPS legislation in 2010 failed.

Because many states have or are in the process of enacting renewable portfolio requirements, it is important to specify if, and how, CCS will affect such requirements. Will the percentage of renewable energy that is required be based on the electric power generated or will it be based on the power generated minus production whose emissions are sequestered? How will future leakage of sequestered CO₂ be treated in regards to renewable requirements? Most of the laws are silent as to the effect that CCS will have on RPS requirements. One approach is to consider CCS the equivalent of renewable energy and to issue RECs for CO₂ sequestered that will help meet an RPS requirement. This would mean that CCS would compete with other renewable resources for an electric power generator's capital investment dollars. Another possibility is that CCS would lower the total electric power generated against which the RPS is calculated. This would allow CCS investments to lower RPS requirements. A third possible approach would be to treat CCS as having no effect on RPS requirements. The second approach would appear to be the most desirable approach.

§ 3(e). Tort Liability

²⁵⁵ Davies, *supra* note 274, at 1400 (App. C).

²⁵⁶ See generally Davies, *supra* note 274.

²⁵⁷ Carolyn Whetzel, *State's Utilities Face Variety of Hurdles In Drive to Meet Renewable Energy Standard*, 39 Env't Rep. (BNA) 1610 (Aug. 8, 2008).

²⁵⁸ Neal J. Cabral, *The Role of Renewable Portfolio Standards in the Context of a National Carbon Cap-and-Trade Program*, 8 SUSTAINABLE Dev. L. & Pol'y 13 (Fall 2007).

²⁵⁹ Congressional Budget Office Cost Estimate, H.R. 2454, American Clean Energy and Security Act of 2009, 8.

A barrier to the implementation of CCS is the potential liability for mishaps. Injected CO₂ could be released to the atmosphere through undetected faults or abandoned well bores. Large releases that create CO₂ concentrations above thirty percent could cause death from asphyxiation; lower concentrations would have adverse effects on the health of humans, animals and plants. The pressure created by injecting large quantities of CO₂ below ground results in CO₂ moving upwards and spreading laterally, which could contaminate potable groundwater, contaminate hydrocarbon resources, create ground heave, or possibly trigger seismic events.²⁶⁰ Such issues should be addressed in federal statutes authorizing a CCS program. Congress could impose or limit liability. For example, the Carbon Storage Stewardship Trust Fund Act of 2009 (S. 1502) that was introduced July 22, 2009, would require operators to have private liability insurance. DOE would be authorized to collect fees from operators to cover possible future liability after the facility was closed.²⁶¹

The Price Anderson Act provides one example of an established liability regime for energy production. This liability regimen for the nuclear energy program provides a strict liability compensation system with an imposed public/private insurance program.²⁶² A similar approach was taken in the Trans-Alaska Pipeline Systems Act.²⁶³ There is also a comprehensive financial liability mechanism for dealing with oil spills in the Oil Pollution Act.²⁶⁴ In the absence of a federal compensation program, traditional tort and property-based legal remedies would apply. In such cases, it is highly unlikely that a federal common law would be recognized; the state law where the injury occurred would be the applicable law.²⁶⁵ However, if a comprehensive federal CCS program is created, the defendant in a state tort-based action may or may not be protected if it is in compliance with federal requirements, depending on whether federal law is interpreted as fully pre-empting state law.²⁶⁶ Federal law is likely to play an important role in determining the appropriate standard of care or what is reasonable conduct in a state tort action. It has been suggested that for the first dozen CCS projects the government should assume all tort liability in order to spur the development of carbon sequestration. But such an action may have an adverse impact on the selection of safe sites and could encourage risky behavior on the part of operators.²⁶⁷

²⁶⁰ Klass & Wilson, *Liability*, *supra* note 52, at 129.

²⁶¹ See Dean Scott, *Senators Offer Bill Addressing Liability Issues Raised by Long-Term Carbon Dioxide Storage*, 40 Env't Rep. (BNA) 1822 (July 31, 2009).

²⁶² 42 U.S.C. § 2210 (Lexis 2010).

²⁶³ Pub. L. No. 93-153 (Nov. 16, 1973), codified at 43 U.S.C. § 1653 (Lexis 2010).

²⁶⁴ Oil Pollution Act §§ 1001-1020, 33 U.S.C. §§ 2701-2720 (Lexis 2010).

²⁶⁵ Int'l Paper Co. v. Ouellette, 602 F. Supp. 264, 269 (D. VT 1985), *affirmed* 776 F.2d 55 (2d Cir. 1985), *affirmed* 479 U.S. 481 (1987).

²⁶⁶ Milwaukee v. Ill., 451 U.S. 304 (1981); Middlesex County Sewage Auth. v. Nat'l Sea Clammers Ass'n, 453 U.S. 1 (1981); Nat'l Audubon Soc'y v. Los Angles Dept. of Water, 869 F.2d 1196 (9th Cir. 1988).

²⁶⁷ Klass & Wilson, *Liability*, *supra* note 52, at 110.

A significant case that deals with federal preemption is *Roberts v. Florida Power & Light Company*.²⁶⁸ In this 1998 case the Eleventh Circuit held that the Price-Anderson Act set the standard of care in an action based on negligence and strict liability for radiation injuries to a worker at a nuclear power facility. This was a “public liability action” within the meaning of the Price-Anderson Act.²⁶⁹ The issue of concern to the Eleventh Circuit was whether Price-Anderson and federal radiation regulations or state tort standards should be used to determine tort liability. The plaintiff made no assertion that the defendant’s emissions exceeded the maximum dose allowed by federal law. The U.S. Supreme Court had previously ruled that the Price-Anderson Act did not preempt a state award of punitive damages.²⁷⁰ But since that ruling, Congress barred punitive awards in 1988 amendments to Price-Anderson where the federal government would be liable for them under an indemnification agreement.²⁷¹ Price-Anderson says the substantive law in a public liability action shall be derived from state law, unless the law of the state in which the nuclear incident occurred is inconsistent with the provisions of section 2210. The Eleventh Circuit agreed with the 3rd, 6th, and 7th Circuits that federal nuclear regulations establish the exclusive standard of care owed by operators of nuclear power plants to their workers.²⁷² As succinctly stated by the 7th Circuit, “state regulation of nuclear safety, through either legislation or negligence actions, is preempted by federal law.”²⁷³ Thus in the case of nuclear power plants, there has been general agreement among the circuits that federal regulations form the sole duty of care owed by operators of nuclear power plants toward their employees.²⁷⁴

The Tenth Circuit court, however, departed from this clear preemption stance in *Cook v. Rockwell International Corporation*, a recent decision involving trespass and nuisance claims against a nuclear facility in Colorado.²⁷⁵ Instead of looking to federal regulations to provide “the sole measure of the defendants’ duty,”²⁷⁶ as five other circuit courts have done,²⁷⁷ the Tenth Circuit held that the 1988 amendments to the Price Anderson Act (PAA) “expressly maintained the applicability of state tort law in PAA actions.”²⁷⁸ Based on a threshold requirement that the plaintiff prove that a “nuclear incident” had occurred according to PAA

²⁶⁸ 146 F.3d 1305 (11th Cir. 1998).

²⁶⁹ See 42 U.S.C. § 2014 (West 2010).

²⁷⁰ *Silkwood v. Kerr-McGee Corp.*, 464 U.S. 238 (1984).

²⁷¹ See 42 U.S.C. § 2210(s) (West 2010).

²⁷² See, e.g., *In re TMI Litigation Cases Consolidated*, 940 F.2d 832, 858-66 (3d Cir. 1991).

²⁷³ *O’Connor v. Commonwealth Edison Co.*, 13 F.3d 1090, 1105 (7th Cir. 1994).

²⁷⁴ See *Roberts v. Florida Power & Light Co.*, 146 F.3d at 1308.

²⁷⁵ *Cook v. Rockwell Int’l Corp.*, 618 F.3d 1127, 1143 (10th Cir. 2010).

²⁷⁶ *Roberts v. Florida Power & Light Co.*, 146 F.3d 1305, 1308 (11th Cir. 1998) (quoting *O’Connor v. Commonwealth Edison Co.*, 13 F.3d 1090, 1105 (7th Cir. 1994)).

²⁷⁷ See *id.*; *O’Connor v. Commonwealth Edison Co.* 13 F.3d at 1105; *Nieman v. NLO, Inc.*, 108 F.3d 1546 (6th Cir. 1997); *In re TMI Litigation Cases Consol. II*, 940 F.2d 832 (3d Cir. 1991); see also *In re Hanford Nuclear Reservation Litig.*, 534 F.3d 986, 1003 (9th Cir. 2008) (cited by the 10th Cir. as another case holding in favor of preemption).

²⁷⁸ *Cook v. Rockwell Int’l Corp.*, 618 F.3d at 1144.

standards, the Tenth Circuit disputed other circuit conclusions that “state tort standards of care, which may have some indirect effect on nuclear safety, are preempted by federal law.”²⁷⁹ Without the proof of a nuclear incident, a plaintiff might still be able to get relief through state tort law. And the determination of whether such laws were preempted by federal nuclear regulations or set a standard of care in conflict with federal standards should be done on a case-by-case basis.²⁸⁰ Such case-by-case uncertainty can be a serious barrier for development of new and potentially dangerous technologies, such as nuclear power and CCS.

While there is no current decision to reconcile these cases,²⁸¹ the process of determining whether federal law preempts state law is based on important considerations that would be relevant for carbon sequestration legislation. First, “there is a strong presumption against preemption that may only be overcome by “clear and manifest” congressional intent to oust state law.”²⁸² Second, this presumption is stronger when preemption would displace the traditional power of the state to protect the health and safety of its citizens.²⁸³ Third, if preemption leaves an injured person without a state or federal remedy, “a court may ascribe preemptive intent to Congress only in the most compelling circumstances.”²⁸⁴ Even if state law is not expressly preempted by Congress, it may be impliedly preempted if Congress occupies the entire field or the state law directly conflicts with federal law and stands as an obstacle to the federal legislative objectives.²⁸⁵ However, as seen from the Cook case, conflict preemption may still leave room for state tort laws to apply. In the absence of express federal preemption, the courts would be unlikely to find there was implied federal preemption because federal CCS laws occupy the field to the exclusion of state tort or property law or because the state law conflicts with federal law.²⁸⁶

On December 7, 2009, the Administrator made an endangerment finding that six GHGs are air pollutants that may be reasonably anticipated to endanger public health and welfare. EPA did not issue a finding that the endangerment finding

²⁷⁹ *Id.* at 1143.

²⁸⁰ *Id.* at 1144. The court cited defendants’ failure to plead “field preemption” as opposed to “conflict preemption” as one basis for its departure from five other circuit court decisions in favor of preemption. *Id.* at 1144, note 19. It also distinguished between a Supreme Court ruling that only the federal government can directly regulate nuclear safety and analysis of preemption of state tort standards, which it claimed was lacking. *Id.* at 1143.

²⁸¹ It might be possible to reconcile them by looking at the 10th Circuit case as an outlier because the defendant failed to argue field preemption. However, this analysis is undercut by the 10th Circuit analysis that the Supreme Court has not yet decided the preemption issue and its directions for case-by-case analysis of whether state law should be preempted.

²⁸² *Wisconsin Public Intervenor v. Mortier*, 501 U.S. 595, 605, 611 (1991).

²⁸³ *See Rice v. Santa Fe Elevator Corp.*, 331 U.S. 218, 230 (1947).

²⁸⁴ *See Silkwood v. Kerr-McGee Corp.*, 464 U.S. 238, 251 (1984).

²⁸⁵ *See Florida Lime & Avocado Growers, Inc v. Paul*, 373 U.S. 132, 142-43 (1993); *Hines v. Davidowitz*, 312 U.S. 52, 67 (1941).

²⁸⁶ *See generally Capollone v. Liggett Group, Inc.*, 112 S. Ct. 2608 (1992); *California Coastal Commission v. Granite Rock Co.*, 107 S. Ct. 1419 (1987).

cannot be the basis for tort actions. Instead, it responded as follows to concerns about increased litigation:

[T]he Administrator focuses her endangerment analysis on the science of GHGs and climate change, and not on the potential ramifications for civil tort litigation (corporate- or environmental justice-related) of regulations that may follow positive endangerment and cause or contribute findings.

This [endangerment finding] action is not the appropriate forum for opining on civil tort litigation. The issues before EPA concern the contribution of emissions from new motor vehicles and the impacts of the air pollution on the public health or welfare.²⁸⁷

Because EPA has not yet issued a finding that its endangerment determination cannot be the basis for tort actions, it can reasonably be expected that many new tort cases will be filed.

A potential plaintiff in a tort action must plead a cause or causes of action that the legal system will recognize and provide a remedy if the plaintiff prevails. Almost any tort or property-based cause of action could potentially be the basis for a lawsuit brought to recover for personal injury or property damage caused by CCS. However, it can reasonably be predicted that nearly all actions will be based on private nuisance, trespass, public nuisance, negligence, or strict liability. Because plaintiffs are allowed to plead alternative causes of action, cases are likely to be brought that are based on multiple legal theories. Assuming the absence of federal preemption over state tort-based action, tort law offers a much greater range of remedies than is presently available under federal environmental laws. State tort law can provide injunctive relief and other equitable remedies. It provides compensatory money damages for personal injury and property damage and may allow for the recovery of punitive damages. The MTBE (methyl tertiary butyl ether) cases show that contamination of ground water can lead to damages in the hundreds of millions of dollars.²⁸⁸

A private nuisance has its roots in property law. It is an indirect (or non-trespassory) invasion on another's interest in the private use and enjoyment of land.²⁸⁹ It may involve interference with the physical condition of land, such as polluting ground water, or it may disturb the occupants of the land, which may

²⁸⁷ EPA. Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act: EPA's Response to Public Comments

(Vol. 11: Miscellaneous Legal, Procedural, and Other Comments), § 111.12.2, *available at* <http://www.epa.gov/climatechange/endangerment/comments/volume11.html#12-2>.

²⁸⁸ See Arnold W. Reitze, Jr., *Biofuels – Snake Oil For the Twenty-First Century*, 87 OREGON L. REV. 1183 (2009).

²⁸⁹ Restatement of Torts, § 822.

occur if air pollutants impact the property.²⁹⁰ It includes a threat of future injury, such as may occur when explosives or toxic material are stored on the land.²⁹¹ The invasion usually must be a substantial invasion of the property that is unreasonable, based on the values within the community. Determining whether conduct is an unreasonable interference requires a balancing of the interests of the parties.²⁹² For potential defendants a nuisance cause of action is always a risk because an activity may be ruled a nuisance by a court even if the activity is lawful and properly operated.²⁹³

Trespass is a direct interference with the right to exclusive possession of land.²⁹⁴ Until the 1960s, trespass was not a cause of action that could provide relief for most environmental-based interferences with land because the release of intangibles such as air pollutants, light, energy, etc. onto another's land was not considered a direct interference with possession of land.²⁹⁵ This has changed, and the most important cases recognizing trespass as a valid cause of action to address air pollution are a series of cases in Washington and Oregon in the 1960s that involved fluoride emissions.²⁹⁶ A trespass can be committed above or below the surface of the land.²⁹⁷ Trespass offers the advantage that the statute of limitations begins when the interference causes substantial harm, but for a continuing trespass it begins anew with each invasion.²⁹⁸ The trespass doctrine is now an established remedy for aircraft over flights when there is a substantial interference with the use of land.²⁹⁹ With modern pleading allowing alternative causes of action, private nuisance and trespass are usually both pleaded in a complaint. Trespass could be used by a plaintiff who can demonstrate reasonable and foreseeable damages from a defendant who engages in unauthorized use of the plaintiff's property interest in an underground pore space.³⁰⁰ The ability to use trespass as a cause of action could be diminished if a CCS regimen defined reasonable conduct and potential defendants could demonstrate that they acted within the permissible limits of the authorizing

²⁹⁰ See generally Julian Conrad Juergensmeyer, *Control of Air Pollution Through the Assertion of Private Rights*, 1967 DUKE L. J. 1126 (1967); Harold W. Kennedy & Andrew O. Porter, *Air Pollution: Its Control and Abatement*, 8 VAND. L. REV. 854 (1955).

²⁹¹ W. PAGE KEETON, ET AL., PROSSER AND KEETON ON TORTS § 87, 619-620 (5th ed. 1984) [hereinafter PROSSER]

²⁹² *Id.* at § 88A, 630.

²⁹³ See e.g., *Tiegs v. Watts*, 954 P.2d 877 (Wash. 1998).

²⁹⁴ PROSSER, *supra* note 319, at § 13, 67.

²⁹⁵ *Id.* at 71

²⁹⁶ See e.g. *Reynolds Metals v. Lampert*, 316 F.2d 272, *rev'd*, 324 F.2d 465 (9th Cir. 1963), *cert. denied*, 376 U.S. 910 (1964).

²⁹⁷ RESTATEMENT OF TORTS (SECOND) § 519; PROSSER, *supra* note 319 at § 13, 82.

²⁹⁸ PROSSER, *supra* note 319, at § 13, 83.

²⁹⁹ *Id.* at 81.

³⁰⁰ IOGCC, *supra* note 231, at 21.

legal authority.³⁰¹ The limited case law on this subject deals primarily with secondary oil and gas recovery operations.³⁰²

Public nuisance developed historically as an omnibus criminal offense that allowed the government to prevent interference with the rights of the community.³⁰³ This cause of action often involves the government as the plaintiff, but an individual may also use this doctrine. A private right of action based on public nuisance requires the plaintiff to have suffered damage over and beyond that suffered by the public at large, and the injury must be different in kind, rather than in degree, from the injury suffered by the public.³⁰⁴ Personal injury or a business interference suffered by only a limited group within the community will probably support a claim for public nuisance.

On January 13, 2009, a North Carolina federal district court ruled that the emissions from TVA's coal-fired power plants in Tennessee and Alabama constituted a public nuisance in North Carolina, based on state law, despite the plant's compliance with CAA permits issued by Tennessee and Alabama.³⁰⁵ The court based its decision on the principles found in the Restatement of Torts § 821B(1) and (2) and required TVA to abate emissions at a cost of more than \$1 billion beyond the \$3 billion TVA had already planned to spend to reduce its emissions.³⁰⁶ The TVA's emissions were released up to 100 miles from North Carolina and were a small part of the pollution load in the state. Moreover the pollutants that allegedly caused harm were secondary pollutants, formed from releases from many sources after undergoing chemical change in the atmosphere. The case involved a judge in a downwind state determining what controls should be required in an upwind state. The court's decision that the defendants were responsible for harm over a large area could have allowed many potential plaintiffs to sue for damages, with the liability of the defendants already established based on the doctrine of collateral estoppel.³⁰⁷ The case was appealed to the Fourth Circuit, which, on July 26, 2010, reversed, saying that the lower court's decision would encourage courts to use the vague public nuisance standards "to scuttle the nation's carefully created system for accommodating the need for energy production and the need for clean air."³⁰⁸ The court went on to say, "It is difficult to understand how an activity expressly permitted and extensively regulated by both federal and state

³⁰¹ See *R.R. Comm'n of Texas v. Manziel*, 361 S.W.2d 560, 568 (Tex. 1962). But see *Mongrue v. Monsanto*, 249 F.3d 422, 433 n.17 (5th Cir. 2001), where, in dicta, the court held that a valid permit did not necessarily bar a trespass action for disposal of hazardous waste using underground injection.

³⁰² IOGCC, *supra* note 231.

³⁰³ Robert Abrams & Val Washington, *The Misunderstood Law of Public Nuisance: A Comparison with Private Nuisance Twenty Years After Boomer*, 54 ALB. L. REV. 359, 362 (1990).

³⁰⁴ PROSSER, *supra* note 319, at § 90, 643.

³⁰⁵ N.C. *ex rel* Cooper v. Tenn. Valley Auth., 593 F. Supp. 2d 812, 829-34 (W.D. N.C. 2009).

³⁰⁶ Tennessee Valley Authority, *TVA Files Appeal in North Carolina Lawsuit* (May 29, 2009), available at <http://www.tva.gov/news/releases/aprjun09/ncappeal.htm> (last visited July 20, 2009).

³⁰⁷ R. Trent Taylor, *State of North Carolina v. TVA—A New Era in Public Nuisance Law?*, 24 Toxics L. Rep. (BNA) 352 (March 12, 2009).

³⁰⁸ N.C. v. Tenn. Valley Auth. (TVA), 615 F.3d 291 (4th Cir. 2010).

government could somehow constitute a public nuisance.”³⁰⁹ It would appear that the court’s opinion could extend to any nuisance case involving an activity subject to a clearly articulated national regulatory policy.³¹⁰

The first lawsuit to be filed to abate carbon dioxide emissions based on public nuisance was *Connecticut v. American Electric Power*, in which eight states, the city of New York, and three environmental groups sued five electric utilities that are the five largest emitters of CO₂ in the United States.³¹¹ The plaintiffs sued the utilities seeking “abatement of [their] ongoing contribution to the public nuisance of global warming.” The district court ruled this was a political question and dismissed the case.³¹² The case was appealed to the Second Circuit where the procedural ruling was reversed, and the case was remanded to go forward for trial based on public nuisance under federal common law.³¹³ The court provided an exhaustive review of the law concerning nonjusticability based on the political question doctrine as well as the law of standing in its process of deciding the case is to go forward. The Second Circuit held that state, municipal, and private plaintiffs may seek injunctive relief for injuries alleged to be caused by climate change. Moreover, the court held that to have standing the plaintiff need only show the defendant’s discharge contributed to the kinds of injury suffered by the plaintiff—there is no requirement to show specific causation. This does not mean, however, that specific causation is not required to prevail on a public nuisance claim. On August 2, 2010 the power companies petitioned for a writ of certiorari asking the Supreme Court to reverse the Second Circuit’s decision allowing the nuisance case to move forward.³¹⁴ In December of 2010, the Court granted certiorari.³¹⁵ So far, 14 amicus briefs have been filed.

On October 16, 2009, the Fifth Circuit unanimously reversed the district court decision in *Comer v. Murphy Oil*.³¹⁶ This case involves private property owners suffering damages from Hurricane Katrina who sued Murphy Oil and dozens of other defendants, primarily energy firms. The plaintiffs claim defendants’ emissions

³⁰⁹ *Id.* at 296.

³¹⁰ See Stuart Parker, *Ruling Could Hinder Activists’ Push for Climate, Emissions Nuisance Suits*, XXI CLEAN AIR REP. (INSIDE EPA) 16:22 (AUG. 5, 2010).

³¹¹ See Edward Lewis, *et al.*, *Following Second Circuit’s Lead, Fifth Circuit Revives GHG Mass Tort Claims, available at* http://www.fulbright.com/index.cfm?fuseaction=publications.detail&site_id=494&pub_id=4197 (last visited Dec. 30, 2010). The defendants are American Electric Power Co., American Electric Power Service Corp. (which does not generate CO₂ emissions), Southern Company, TVA, Xcel Energy, and Cinergy Corp.

³¹² *Conn. v. Am. Elec. Power Co.*, 406 F. Supp. 2d 265 (S.D.N.Y. 2005). See Lori R. Baker, note, *Global Warming: Attorneys General Declare Public Nuisance*, 27 U. HAW. L. REV. 525 (2005).

³¹³ *Conn. v. Am. Elec. Power Co.*, 582 F.3d 309, 393 (2d Cir. 2009).

³¹⁴ Doug Obey, *Utilities Target States’ Standing in Bid To Reverse Climate Nuisance Suit*, XXI CLEAN AIR REP. (Inside EPA) 16:25 (Aug. 5, 2010); Steven D. Cook, *Four Electric Utilities Ask Supreme Court To Review Second Circuit Nuisance Decision*, 41 Env’t Rep. (BNA) 1763 (Aug. 6, 2010).

³¹⁵ *Conn. v. Am. Elec. Power Co.*, 582 F.3d 309, *cert. granted*, No. 10-174 (U.S. Dec. 6, 2010).

³¹⁶ *Comer v. Murphy Oil USA*, 585 F.3d 855 (5th Cir. 2009).

contribute to global warming that increases surface air and water temperatures that added to the intensity of Katrina. Unlike the *Connecticut v. AEP* case, which sought injunctive relief, the Mississippi property owners want compensatory and punitive damages based on the Mississippi tort laws of public and private nuisance, trespass, negligence, unjust enrichment, fraudulent misrepresentation, and civil conspiracy. The Fifth Circuit three-judge panel ruled the plaintiffs have standing and adopted the Second Circuit's "fairly traceable" standard of causation for standing.³¹⁷ The court allowed the public and private nuisance, trespass and negligence claims to go forward, but the unjust enrichment, fraudulent misrepresentation, and civil conspiracy claims lacked "prudential standing" and were dismissed.³¹⁸ However, on February 26, 2010, the ruling was vacated when the case was granted an *en banc* hearing. On May 28, 2010, the court said it could not rehear the matter because so many judges had recused themselves that it lacked a quorum. Following court procedure, the appeal was dismissed and the panel decision remains vacated, thus ending the plaintiffs' standing to sue for damages related to global warming.³¹⁹

On September 30, 2009, the Federal District Court for the Northern District of California dismissed claims by the Native Village of Kivalina and the City of Kivalina, Alaska against twenty-four energy and oil companies. The claims were based on the federal common law of nuisance.³²⁰ The district court dismissed the Kivalina case, which sought \$400 million to allow the plaintiffs to relocate, based on lack of subject matter jurisdiction due to the perceived political nature of global warming solutions and because the plaintiffs could not prove the causation necessary to gain standing.³²¹ The case was appealed to the Ninth Circuit, where it was still pending at the end of December, 2010. Plaintiffs are seeking review of the political question doctrine, standing issues, and preemption of public nuisance claims by the Clean Air Act (CAA).

Two of the three nuisance cases concerning carbon dioxide emissions, discussed above, involve the federal common law of public nuisance.³²² The first significant air pollution cases based on federal common law public nuisance were four cases decided between 1907 and 1916 in which the State of Georgia was successful in obtaining equitable relief for emissions released by the Tennessee Copper Company.³²³ In the final decree, the Court imposed emission limits and monitoring requirements.³²⁴ Many federal public nuisance cases have subsequently

³¹⁷ *Id.* at 864-65.

³¹⁸ See Steven Patrick, *Fifth Circuit Joins Second in Ruling Courts May Hear Cases on Damages from Warming*, 40 Env't Rep. (BNA) 2444 (Oct. 23, 2009).

³¹⁹ *Comer v. Murphy Oil USA*, 607 F.3d 1049 (5th Cir. 2010). See also *Recusal Prompts Appellate Court to Drop Key Suit Allowing GHG Tort Claims*, XXI CLEAN AIR REP. (Inside EPA) 12:20 (June 10, 2010).

³²⁰ Native Village of Kivalina v. Exxon Mobile Corp., 663 F.Supp. 2d 863 (N.D. Cal. 2009).

³²¹ *Id.* at 881-82. See also Lewis, *supra* note 339.

³²² *Conn. v. Am. Elec. Power Co.*, 582 F.3d 309 (2d Cir. 2009); Native Village of Kivalina v. Exxon Mobile Corp., 663 F.Supp. 2d 863 (N.D. Cal. 2009).

³²³ *Georgia v. Tenn. Copper Co.*, 206 U.S. 230 (1907); 237 U.S. 474 (1915); 237 U.S. 678 (1915); and 240 U.S. 650 (1916).

³²⁴ *Georgia v. Tenn. Copper Co.*, 240 U.S. at 650-51.

been decided, but it was not until about 1973 that the federal courts turned to the Restatement (Second) of Torts to determine the applicable rules for federal public nuisance cases.³²⁵ In 1971 the Supreme Court ruled that states could bring public nuisance claims in the federal district courts rather than using the Supreme Court as the only court with original jurisdiction for such cases.³²⁶ Several district courts interpreted this case to allow municipalities to bring federal common law nuisance claims.³²⁷ The federal government also may bring nuisance-based cases.³²⁸

It is still not clear whether a private party may bring a federal common law nuisance action, although the Third Circuit has allowed such an action.³²⁹ In 1972 the Court, in *Milwaukee I*, held sewage discharge could be the subject of a federal common law public nuisance action brought by a state in federal district court because the existing statutes did not cover the plaintiff's claims and did not provide a remedy.³³⁰ The Court warned, however, that "new federal laws and new federal regulations may in time pre-empt the field of federal common law of nuisance."³³¹ This came to pass, and the use of federal public nuisance in environmental cases received a set back in *Milwaukee II*, when the Court ruled that the establishment of a comprehensive federal program for the control of water pollution subsequent to *Milwaukee I* precluded the federal courts from using federal common law to impose more stringent requirements than were imposed by the Federal Water Pollution Control Act (FWPCA).³³² While it would be difficult to claim that a comprehensive federal program for CO₂ exists at this time, the efforts of EPA to control CO₂ using the CAA may soon displace the use of federal common law of nuisance as a cause of action.

An important aspect of private nuisance, public nuisance, and trespass is that these causes of action may result in equitable relief for the successful plaintiff, such as abatement of the nuisance, or, in an extreme case, shutting down a business.³³³ In addition, money damages may be awarded. If the harm to the community from granting equitable relief is significant, however, only money damages may be

³²⁵ RESTATEMENT (SECOND) OF TORTS, §§ 886A, 821B. *See, e.g.*, *United States v. Bushey & Sons, Inc.*, 363 F. Supp. 110, 120-21 (D. Vt. 1973), *aff'd* 487 F.2d 1393 (2d Cir. 1973), *cert. denied*, 417 U.S. 976 (1974); *U.S. v. Solvents Recovery Service of New England*, 496 F. Supp. 1127, 1139-40 (D.C. Conn. 1980).

³²⁶ *Ohio v. Wyandotte Chemicals Corp.*, 401 U.S. 493, 495, 498-99 (1971).

³²⁷ *See, e.g.*, *Conn. v. Am. Elec. Power Co.*, 582 F.3d at 361-62 (historical analysis); *City of Evansville v. Ky. Liquid Recycling, Inc.*, 604 F.2d 1008 (7th Cir. 1979).

³²⁸ *See United States v. Stoecco Homes, Inc.*, 498 F.2d 597, 611 (3d Cir. 1974).

³²⁹ *See National Sea Clammers Ass'n v. City of New York*, 616 F.2d 1222, 1233 (3d Cir. 1980), *vacated on other grounds*, *Middlesex County Sewage Auth. v. Nat'l Sea Clammers Ass'n*, 453 U.S. 1 (1981). *But c.f.* *Nat'l Audubon Soc. v. Dep't of Water*, 869 F.2d 1196, 1205-6, 1211-12 (Reinhardt, J., dissenting) (9th Cir. 1988).

³³⁰ *Illinois v. City of Milwaukee (Milwaukee I)*, 406 U.S. 91, 104, 107 (1972).

³³¹ *Id. at 107.*

³³² *Illinois v. Milwaukee (Milwaukee II)*, 451 U.S. 304, 306 (1981). The Court explicitly held the FWPCA displaced federal common law in *Nat'l Sea Clammers* (*see Nat'l Sea Clammers Ass'n v. City of New York*, 616 F.2d at 1221-22).

³³³ *PROSSER*, *supra* note 319, at § 88A, 630.

granted, and the defendant may obtain the equivalent of an easement to continue harmful conduct in return for paying appropriate damages.³³⁴ These causes of action usually involve balancing the benefits to the public from the activity against the harm to the plaintiffs. But if plaintiffs prove significant harm and causation, they will likely recover damages for their injury, even if other injunctive relief is not granted.³³⁵

Negligence is the most common cause of action in the tort system. It requires a duty recognized by law that requires conformity to a standard; a breach of that duty that causes injury to a party; a close causal connection between the conduct and the injury (proximate cause) and an actual loss or damage.³³⁶ For CCS cases it will require showing a duty in an area that has little regulation. Ultimately liability is going to rest on whether a reasonable care standard was met, which requires balancing the social utility of the conduct of the defendant against the risk to members of the public.³³⁷ If a defendant's conduct was unreasonable, a plaintiff must further demonstrate that the defendant's conduct was the cause of the injury.

Strict liability (a.k.a. liability without fault) is imposed on abnormally dangerous activities or conditions.³³⁸ It is normally imposed as a social policy to shift the risk of loss to the entity that can best prevent a harmful event from occurring.³³⁹ Under the Restatement of Torts a balancing among six factors is required. To impose liability, the courts will balance: 1) the degree of risk of harm; 2) the likelihood that the harm will be substantial; 3) and the inability to eliminate the risk with reasonable care; against 4) whether the activity is common; 5) whether the activity is appropriate for a particular location; and 6) the value of the activity to the community in comparison to its risk.³⁴⁰ The doctrine of strict liability has been applied to environmental contamination in 21 of 27 states that have considered this issue.³⁴¹ Two states, Texas and Wyoming, have rejected the doctrine.³⁴²

If the government takes an action that materially limits the use of property, an inverse condemnation action may be brought to recover the value of the property taken. There does not need to be a formal taking using the power of eminent domain nor is physical occupancy required. This doctrine has been used successfully for

³³⁴ See *Boomer v. Atlantic Cement Co.*, 340 N.Y.S. 2d 97, 107-08, *affirmed* N.Y.S. 2d 199.

³³⁵ See *Madison v. Ducktown Sulphur, Copper, and Iron Co.*, 113 Tenn. 331 (Tenn. 1904).

³³⁶ RESTATEMENT (SECOND) OF TORTS § 282; PROSSER, *supra* note 319, at § 30, 164.

³³⁷ See RESTATEMENT (SECOND) OF TORTS §§ 291, 292.

³³⁸ PROSSER, *supra* note 319, at § 78, 545.

³³⁹ PROSSER, *supra* note 319, at § 75, 536.

³⁴⁰ RESTATEMENT (SECOND) OF TORTS § 520.

³⁴¹ 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, 942-61 (2004).

³⁴² Klass & Wilson, *Liability*, *supra* note 52, at 142, *citing* *Doddy v. Oxy USA, Inc.*, 101 F.3d 448, 462 (5th Cir. 1996); *Jones v. Texaco*, 945 F. Supp. 1037, 1050 (S.D. Tex. 1996); *Wyrulec Co. v. Schutt*, 866 P.2d 756, 761 (Wyo. 1993).

damage to or loss of the use of property from nearby highway construction, and it has been used for damage caused by low flying aircraft.³⁴³

Regardless of the legal theory pursued in a tort action involving CCS, proving causation may be a problem. Actions that cause harm may have occurred a decade or more before the case. There also may be problems of proof if the injuries could be the result of exposure to many possible agents that may have been released from a variety of sources.³⁴⁴ If the injury has multiple or an unknown etiology, proving a defendant was responsible can be difficult. Causation problems can also cut the other way. If causation cannot be definitively demonstrated, potential plaintiffs may be encouraged to gamble on a lawsuit.³⁴⁵ The injuries that lead to lawsuits will involve injuries to property and/or injuries to health and the environment. CO₂ dioxide storage can also injure underground mineral, natural gas, petroleum, and water resources. It can induce seismic events or ground subsidence. However, the statute of limitations could run before the harm caused by a potential defendant is discovered. Courts usually combat this problem by imposing a discovery rule that runs from the time the plaintiff knew or should have known of the injury.³⁴⁶

§ 4. Western States CCS Legislation

Coal production in the United States in 2009 totaled 1,075 million short tons; and of this amount, 585 million short tons or 54 percent was produced in the eight western-most states (including Alaska).³⁴⁷ Wyoming dominates western coal production by producing 40.1 percent of the nation's coal, which is more than the combined total of all the Appalachian states.³⁴⁸ In addition, Kansas has gone from two to one surface mine, which produces 0.017% of the nation's coal; Oklahoma has one underground mine and nine surface mines that produce 0.089% of the nation's coal; and Texas has twelve surface mines that produce 3.26% of the nation's coal.³⁴⁹ Among the states in the western half of the United States, Oregon, Washington,

³⁴³ United States v. Causby, 328 U.S. 256 (1946); Thomburg v. Port of Portland, 233 Ore. 178, 376 P.2d 100 (1962).

³⁴⁴ See generally Steve Gold, *Causation in Toxic Torts: Burdens of Proof, Standards of Persuasion, and Statistical Evidence*, 96 YALE L. J. 376 (1986); David Rosenberg, *The Causal Connection in Mass Exposure Cases: A "Public Law" vision of the Tort System*, 97 HARV. L. REV. 849 (1984); Bert Black & David E. Lilienfield, *Epidemiologic Proof in Toxic Tort Litigation*, 52 FORDHAM L. REV. 732 (1984).

³⁴⁵ For examples of cases with questionable causation concerning Swine Flu litigation, see Arnold W. Reitze, Jr., *Federal Compensation for Vaccination Induced Injuries*, 13 B.C. ENVTL. AF. L. REV. 169, 181 (1986).

³⁴⁶ This issue is covered in more detail in Klass & Wilson, *Liability*, *supra* note 52, at 145.

³⁴⁷ U.S. Dep't of Energy, Energy Information Administration, *U.S. Coal Production by Coal-Producing Region and State*, available at <http://www.eia.doe.gov/cneaf/coal/page/acr/tables2.html> (last visited Nov. 11, 2010) [hereinafter EIA Production by State]; *Coal Production and Number of Mines by State and Mine Type*, available at <http://www.eia.doe.gov/cneaf/coal/page/acr/table21.html> (last visited Nov. 11, 2010) [hereinafter EIA Mine Type].

³⁴⁸ EIA Production by State, *supra* note 375.

³⁴⁹ EIA Mine Type, *supra* note 375.

Idaho, Nebraska, and South Dakota produce no coal, although some of these states have coal-burning electric power plants.³⁵⁰

§ 4(a). Alaska's CCS Efforts

Alaska has only one coal mine, which produces 0.17% of the nation's coal.³⁵¹ The Usibelli mine is near Healy and supplies coal to six power plants in Alaska and exports coal to South Korea and other Pacific countries.³⁵² The amount of coal in Alaska is the subject of considerable interest and on-going research. There are vast reserves in the Arctic that are thought to hold as much as half the nation's coal. However, accessing these reserves is not currently economically feasible.³⁵³ There are ongoing efforts to expand coal production in Alaska, primarily for export, but such efforts are the focus of environmentalists' opposition. The six power plants using coal have a total capacity of 136 MW, and none are larger than 50 MW.³⁵⁴ Alaska does not currently have any legislation on geologic CCS.

There are several coal-to-liquids projects underway in Alaska funded by the Department of Defense in an effort to develop synthetic fuels from coal.³⁵⁵ In June of 2010, CIRI and Laurus Energy announced plans to produce syngas from deep underground coal in southcentral Alaska. The in-situ process produces synthetic gas from underground coal, separating CO₂ and other gases underground and storing them there. The proposed project would fuel a 100 MW power plant in Southcentral Alaska.³⁵⁶ If the proposed sequestration takes place, Alaska may soon be forced to deal with the legal issues of sequestration on a commercial scale.

§ 4(b). Arizona's CCS Efforts

Arizona has one surface coal mine that produced a little under 7.5 million tons of coal in 2009.³⁵⁷ There are six coal-fired power plants with 16 operating units in the state with a total capacity of 5,681 MWs.³⁵⁸ The Navajo Generating Station has

³⁵⁰ *Id.* While the Department of Energy lists these states as having no coal production, other data sources list small amounts of production from some of these states. This is discussed *infra* in material on specific states.

³⁵¹ EIA Mine Type, *supra* note 375.

³⁵² Source Watch, *Alaska and Coal* (2010), available at http://sourcewatch.org/index.php?title=Alaska_and_coal (last visited Nov. 17, 2010).

³⁵³ See David Coil, Erin McKittrick, Bretwood Higman, & Ground Truth Trekking, Quantifying Coal: How Much Is There? available at <http://www.groundtruthtrekking.org/Issues/AlaskaCoal/HowMuchCoal.html> (last visited Nov. 17, 2010).

³⁵⁴ Source Watch, *Alaska and Coal*, *supra* note 380.

³⁵⁵ *Id.*

³⁵⁶ CIRI Press Release, Laurus Energy and Ciri Form Joint Venture, June 8, 2010, available at <http://www.ciri.com/content/company/NewsDetails.aspx?ID=743>.

³⁵⁷ EIA Mine Type, *supra* note 375.

³⁵⁸ Source Watch, *Category: Existing Coal Plants in Arizona*, available at http://www.sourcewatch.org/index.php?title=Category:Existing_coal_plants_in_Arizona (last visited Nov. 22, 2010). The plants are Abitibi Snowflake Power Plant, Apache Generating Station, Cholla Generating

three 750 MW units totaling 2,250 MWs. At least twenty-one percent of this power is sent to California. In 2007 this station was ranked as the nation's eighth largest power plant emitter of CO₂.³⁵⁹

On March 25, 2009, the Arizona Department of Environmental Quality (ADEQ) and EPA announced the first permit in the Southwest for a CCS project in Joseph City, Arizona. The Cholla pilot project planned a twenty-day, or less, injection of 2,000 tons of CO₂ into an underground saline formation by the West Coast Regional Sequestration Partnership (WESTCARB), a regional partnership organized by DOE. The ADEQ permit is a temporary one-year aquifer protection permit that requires the holder to meet Arizona aquifer water quality standards and to use the best available technology. In addition, EPA issued a Safe Drinking Water Act Underground Injection Control permit, because it administers the program in Arizona. However, upon testing, WESTCARB determined that the saline aquifer was not sufficiently permeable and is now testing alternative sites for the CCS project.³⁶⁰ This test project is part of the second phase of an Arizona CCS program. The first phase characterized the opportunities for CCS. The second phase involves small-scale field tests. The third phase, to run from 2008 to 2017, is to conduct large-volume carbon storage tests.³⁶¹

Although three CCS pilot projects are currently underway in the state, Arizona does not yet appear to have any legislation specifically regulating CCS.³⁶² On April 26, 2010, Arizona's governor signed H.B. 2442 that forbids state agencies from regulating GHGs without legislative approval.³⁶³ This law may slow or stop efforts to implement CCS. In addition, Arizona has said the state will not participate in current efforts to implement the Western Climate Initiative's cap-and-trade program, which removes a major incentive for utilities to participate in a CCS program.³⁶⁴ However, on December 1, 2010, the EPA included Arizona as one of thirteen states that must adjust its State Implementation Plan to apply PSD

Station, Coronado Generating Station, H. Wilson Sundt Generating Station and the Navajo Generating Station.

³⁵⁹ See Source Watch, *Navajo Generating Station*, available at http://sourcewatch.org/index.php?title=Navajo_Generating_Station (last visited Nov. 22, 2010); Environment Arizona, *America's Biggest Polluters: Carbon Dioxide Emissions from Power Plants 2007*, at 29, available at <http://www.environmentarizona.org/reports/global-warming/global-warming-reports/americas-biggest-polluters-carbon-dioxide-emissions-from-power-plants-in-2007> (last visited Nov. 22, 2010).

³⁶⁰ WESTCARB, *Arizona Utilities CO₂ Storage Pilot—Cholla Site*, available at http://www.westcarb.org/AZ_pilot_cholla.html (last visited Nov. 22, 2010).

³⁶¹ William H. Carlile, *EPA, State Issue One-Year Permit For Pilot Carbon Sequestration Project*, 40 Env't Rep. (BNA) 719 (Mar. 27, 2009).

³⁶² See Lee Allison, *Carbon Capture & Storage Legislation*, ARIZONA GEOLOGY, BLOG OF THE STATE GEOLOGIST OF ARIZONA, (July 26, 2010) available at <http://arizonageology.blogspot.com/2010/07/carbon-capture-storage-legislation.html> (last visited Nov. 22, 2010).

³⁶³ *Arizona Strips Agencies of Greenhouse Gas Authority*, 41 Env't Rep. (BNA) 1026 (May 7, 2010).

³⁶⁴ William H. Carlile, *State Agency Issues Proposed Rule To Establish Cap-and-Trade Program*, 41 Env't Rep. (BNA) 1150 (May 21, 2010).

provisions to GHG emissions. By December 22, 2010, Arizona is ordered to include GHGs as one of the specific pollutants regulated by the PSD program.³⁶⁵

§ 4(c). California's CCS Efforts

There is no coal mined in California.³⁶⁶ California's coal-fired electric power comprises less than one percent of the state's generating capacity. There are eight plants with a total of ten units that have a combined capacity of 439 MWs; five plants have a capacity greater than 54 MWs.³⁶⁷ However California utilities own about 3,500 MW of capacity in five coal-burning plants located in Arizona, Nevada, New Mexico, and Utah.³⁶⁸ In 2007 the California Energy Commission banned the signing of new contracts with out-of-state power plants by municipal and investor-owned electric utilities.³⁶⁹ California limits new coal-fired power plants to 1,100 pounds of CO₂ per megawatt hour (MWh).³⁷⁰ However, by statute, geologically stored CO₂ does not count as a power plant emission in terms of meeting GHG emission performance standards.³⁷¹ The framework for California's response to climate change was established in 2006 with the enactment of A.B. 32, the California Global Warming Solutions Act of 2006.³⁷² The aim of the Act is to reduce GHG emissions, and some experts see CCS as a "critical technology pathway for the state of California in achieving steep GHG reductions."³⁷³ A.B. 32 is discussed *infra* in § 4(c)(1).

California law requires the California Energy Commission (Commission) to adopt a bi-annual integrated energy policy report (IEPR) containing an overview of the major energy trends and issues facing the state in three key areas: 1) electricity and natural gas markets; 2) transportation fuels, technologies, and infrastructure; and 3) public interest energy strategies.³⁷⁴ In 2006 the California legislature

³⁶⁵ Action to Ensure Authority to Issue Permits under the Prevention of Significant Deterioration Program to Sources of Greenhouse Gas Emissions: Finding of Substantial Inadequacy and SIP Call; Final Rule, 40 C.F.R. Part 52 (Docket No. EPA-HQ-OAR-2010-0107).

³⁶⁶ EIA Production by State, *supra* note 375.

³⁶⁷ Source Watch, *California and Coal*, at 5, available at http://www.sourcewatch.org/index.php?title=California_and_coal#Existing_coal_plants (last visited Nov. 22, 2010). The plants are: ACE Cogeneration (108 MW), Port of Stockton District Energy Facility (54 MW), Stockton Cogeneration (60 MW), Mt. Poso Cogeneration (62 MW), and Argus Cogeneration (55 MW).

³⁶⁸ *Id.*

³⁶⁹ *Id.* See California SB 1368; CAL. PUB. UTIL. CODE 8341(d)(5) (West 2010).

³⁷⁰ *Id.* Based on California's SB 1368. The limit is derived from the emissions level of a combined-cycle natural gas base-load generator.

³⁷¹ See CAL. PUB. UTIL. CODE 8341(d)(5) (West 2010).

³⁷² See California Air Resources Board, *AB 32 Fact Sheet—California Global Warming Solutions Act of 2006* (Sept. 25, 2006).

³⁷³ S. Julio Friedman, *Reducing Emissions in California Through Carbon Capture and Sequestration*, available at <http://www.arb.ca.gov/research/seminars/friedmann/friedmann.htm> (last visited Dec. 30, 2010).

³⁷⁴ CAL. PUB. RES. CODE § 25302(a) (West 2010).

unanimously passed Assembly Bill 1925, An Act Relating to Energy (AB 1925), which adds geologic carbon sequestration as a topic to be addressed in the Commission's bi-annual IEPR.³⁷⁵ AB 1925 requires that on or before November 1, 2007:

[T]he State Energy Resources Conservation and Development Commission, in coordination with the Division of Oil, Gas, and Geothermal Resources of the Department of Conservation and the California Geological Survey, shall submit a report to the Legislature containing recommendations for how the state can accelerate adoption of cost-effective geologic sequestration strategies for the long-term management of industrial carbon dioxide. In formulating recommendations, the commission shall meet with representatives from industry, environmental groups, academic experts, and other government officials, with expertise in indemnification, subsurface geology, fossil fuel electric generation facilities, advanced carbon separation and transport technologies, and greenhouse gas management.³⁷⁶

AB 1925 mandates carbon sequestration issues be included in the report, which is discussed *infra*.³⁷⁷ AB 1925 also requires the IEPR to support research and development in the following areas.

- 1) Identify and characterize state geological sites that potentially are appropriate for long-term storage of carbon dioxide.
- 2) Evaluate the comparative economics of various technologies for capture and sequestration of carbon dioxide.
- 3) Identify technical gaps in the science of sequestration of carbon dioxide to be prioritized for further analysis.
- 4) Evaluate the potential risks associated with geologic sequestration of carbon dioxide, including leakage resulting from carbonates and other dissolved minerals.
- 5) Evaluate the potential risks if geologically sequestered carbon dioxide leaks into aquifers.
- 6) Evaluate, and to the extent feasible quantify, the potential liability from the leakage of geologically sequestered carbon dioxide and potentially responsible parties.³⁷⁸

³⁷⁵ CAL. PUB. RES. CODE § 25302 (West 2010). Section 25302 was added in 1974 and has been amended by multiple session laws, including Section 1 of Stats. 2006, c. 471 (A.B.1925). The text of AB 1925 is found in historical and statutory notes for § 25302. Section 1 of Stats. 2006, c. 471(a)(3) (A.B.1925) requires the Commission to include carbon sequestration in its bi-annual report.

³⁷⁶ Section 1 of Stats. 2006, c. 471(a)(1) (A.B.1925).

³⁷⁷ Section 1 of Stats.2006, c. 471(a)(2)(A) - (C) (A.B.1925).

³⁷⁸ Section 1 of Stats.2006, c. 471(b) (A.B.1925).

As mandated by AB 1925, in February 2008 the Commission and California Department of Conservation released a 139-page joint report entitled *Geologic Carbon Sequestration Strategies for California: Report to the Legislature* (Joint Report).³⁷⁹ The ten chapters of the report address the following issues: 1) Role of Carbon Sequestration in Climate Change Mitigation in California; 2) Key Implementation Issues; 3) Potential for Capture and Geologic Sequestration; 4) Capture Technologies; 5) Site Characterization; 6) Monitoring and Verification; 7) Risks and Risk Management; 8) Remediation and Mitigation of CO₂ Leakage; 9) Economic Considerations; and 10) Regulatory and Statutory Issues.³⁸⁰

The executive summary of the report makes five recommendations and calls for a more comprehensive analysis to be completed in 2010. The five recommendations are:

1. Over the next three years, any state planning and other analyses involving energy or greenhouse gas emissions reduction strategies, as appropriate, should include consideration of carbon capture and sequestration options. Improved cost estimates should be developed, and policy makers at all levels of government should consider them an appropriate proxy for the long-term value of CO₂ reduction.
2. Further examination is needed of the scenarios for carbon capture and sequestration adoption identified in this report as early opportunities, based on potentially close-to-favorable business cases. These opportunities may have greater value than as niche applications and may facilitate creation of an in-state market for CO₂ by demonstrating enhanced oil and gas production.
3. Demonstration projects in the United States and around the world over the next three years will provide key data to set carbon capture and sequestration policy. They should be facilitated and carefully studied, and may provide early insight into public and property owner's concerns about risks.
4. California's power imports encourage consideration of carbon capture and sequestration in a regional context. Coordinated investigations of carbon capture and sequestration for power plants should take place involving other states in the Western Electricity Coordinating Council region. This should be done in the context of recognizing the connection between regional climate change and electricity generation objectives and involve

³⁷⁹ CALIFORNIA ENERGY COMMISSION & CALIFORNIA DEPARTMENT OF CONSERVATION, GEOLOGIC CARBON SEQUESTRATION STRATEGIES FOR CALIFORNIA: REPORT TO THE LEGISLATURE (February 2008) available at <http://www.energy.ca.gov/2007publications/CEC-500-2007-100/CEC-500-2007-100-CMF.PDF> (last visited Dec. 30, 2010).

³⁸⁰ *Id.* at v-viii.

consideration of how carbon responsibility should “flow” with electricity.

5. Regulatory and statutory ambiguities and barriers identified in this report must be addressed, potentially through efforts that cut across the agencies that will ultimately be involved in regulating carbon capture and sequestration, from surface facilities through injection to sequestration and verification of climate change mitigation. These efforts would include evaluating the need for protocols and, as applicable, drafting them. This would include protocols for site characterization, monitoring and verification, and contingency plans for remediating leakage.³⁸¹

§ 4(c)(1). California Assembly Bill 32, The California Global Warming Solutions Act and Scoping Plan.

In 2006 the California legislature passed Assembly Bill 32, the California Global Warming Solutions Act of 2006 (AB 32).³⁸² The goal of AB 32 is to reduce GHG emissions to 1990 levels by 2020 by having the California Air Resources Board (CARB) adopt concrete GHG reduction measures by 2011.³⁸³ In 2010, AB 32 was targeted by Valero Energy Corporation and other oil companies, who succeeded in putting a voter initiative on the November 2010 ballot. The initiative would have suspended implementation of AB 32 until the state’s unemployment rate remained at 5.5% for a year, which has occurred only once in the past 30 years.³⁸⁴ This effort was seen by many as an initiative on AB 32 as well as Californians’ commitment to seriously addressing climate change.³⁸⁵ The initiative failed, with 61% voting against it. However, there are now concerns that another initiative on the same ballot, which was approved (Proposition 26), may still act to curb the effectiveness of AB 32.³⁸⁶ Proposition 26 requires that certain state and local fees be approved by a two-thirds legislative vote. Fees include charges that address adverse impacts on society or the environment caused by the fee-payer’s business. This proposition

³⁸¹ *Id.* at 10.

³⁸² CAL. HEALTH & SAFETY CODE § 38500 *et seq.* (West 2010).

³⁸³ CAL. HEALTH & SAFETY CODE § 38550 (West 2010). *See also* California Environmental Protection Agency, Air Resources Board, Assembly Bill 32: Global Warming Solutions Act, <http://www.arb.ca.gov/cc/ab32/ab32.htm> (last visited Nov. 22, 2010) [hereinafter CEPA AB 32].

³⁸⁴ Carolyn Whetzel, *Economists Conclude Climate Policies Will Have Little Impact on State Economy*, 41 Env’t Rep. 959 (Apr. 30, 2010).

³⁸⁵ Margot Roosevelt, *Prop. 23: Why Did Valero Launch a Campaign Against California’s Climate Law?*, LOS ANGELES TIMES (Oct. 31, 2010), available at <http://latimesblogs.latimes.com/greenspace/2010/10/prop-23-valero-global-warming-oil-refineries.html> (last visited Dec. 30, 2010); *Prop. 23 Battle Marks New Era in Environmental Politics*, LOS ANGELES TIMES (Nov. 4, 2010), available at <http://www.latimes.com/news/local/la-me-global-warming-20101104,0,4277096.story>.

³⁸⁶ *See* Margot Roosevelt, *Lawyers, Lobbyists, Politicians Scramble to Determine Impact of Prop. 26*, LOS ANGELES TIMES (Nov. 14, 2010), available at <http://www.latimes.com/news/local/la-me-prop26-impact-20101115,0,2819277.full.story> (last visited Nov. 22, 2010).

passed with 52.5% of the vote and may apply to a cap-and-trade program.³⁸⁷ The measure will make it more difficult to impose regulatory fees, such as environmental clean-up fees, and it will increase the uncertainty concerning whether a measure is a tax or a fee, which can be expected to lead to litigation. This Proposition was supported by the tobacco, alcoholic beverage, and oil industries.³⁸⁸ However CARB has signaled it does not believe Proposition 26 will derail cap-and-trade,³⁸⁹ and on December 16, CARB approved the cap-and-trade and GHG emissions reduction program outlined by AB 32.³⁹⁰

Several of AB 32's specific mandates have also been completed by CARB. For example, CARB was required to develop a scoping plan to identify the maximum technologically feasible and cost-effective reductions for GHG sources.³⁹¹ "In developing its plan, the state board [CARB] shall identify opportunities for emission reductions measures from all verifiable and enforceable voluntary actions, including, but not limited to, carbon sequestration projects and best management practices"³⁹²

This plan, approved by CARB on December 12, 2008, identifies regulations, market mechanisms and other actions for achieving GHG reductions.³⁹³ CARB is to identify a numeric statewide emission reductions goal needed to reach 1990 GHG levels by 2020.³⁹⁴ In December 2007 CARB approved a 2020 emission limit of 427 million tons of CO₂e.³⁹⁵

AB 32 requires the adoption of a mandatory GHG reporting and verification regulation for GHG emissions.³⁹⁶ In 2007 CARB adopted a regulation requiring the

³⁸⁷ Ballotpedia, *California Proposition 26, Supermajority Vote to Pass New Taxes and Fees* (2010), available at [http://www.ballotpedia.org/wiki/index.php/California_Proposition_26,_Supermajority_Vote_to_Pass_New_Taxes_and_Fees_\(2010\)](http://www.ballotpedia.org/wiki/index.php/California_Proposition_26,_Supermajority_Vote_to_Pass_New_Taxes_and_Fees_(2010)) (last visited Nov. 24, 2010). See also Carolyn Whetzel, *Statew's Voters Reject Ballot Measure To Stall Implementation of Climate Policies*, 41 Env't Rep. (BNA) 2476 (Nov. 5, 2010).

³⁸⁸ Carolyn Whetzel, *Voters Approve Ballot Measure to Require Two-Thirds Vote on State Regulatory Fees*, 41 Env't Rep. (BNA) 2477 (Nov. 5, 2010).

³⁸⁹ See Margot Roosevelt, *Lawyers, Lobbyists, Politicians Scramble to Determine Impact of Prop. 26*, L.A. TIMES, Nov. 14, 2010, available at http://www.latimes.com/news/local/la-me-prop26-impact-20101115_0_2470740.story (last visited Dec. 13, 2010).

³⁹⁰ See CARB, Cap-and-Trade, <http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm> (last visited Dec. 29, 2010).

³⁹¹ CAL. HEALTH & SAFETY CODE § 38561 (West 2010). In addition to calling for a scoping plan, AB 32 also convened an Environmental Justice Advisory Committee (EJAC) to help the ARD develop the scoping plan and implementation of AB 32. CAL. HEALTH & SAFETY CODE § 38591 (West 2010).

³⁹² CAL. HEALTH & SAFETY CODE § 38561(f) (West 2010).

³⁹³ CARB, *Climate Change Scoping Plan: A Framework for Change*, (Dec. 2008), available at <http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm> (last visited Nov. 22, 2010) [hereinafter "CARB Scoping"].

³⁹⁴ CAL. HEALTH & SAFETY CODE § 38550 (West 2010).

³⁹⁵ See CARB Scoping, *supra* note 420, at 5.

³⁹⁶ CAL. HEALTH & SAFETY CODE § 38550 (West 2010).

largest GHG emitters to report and verify their emissions.³⁹⁷ AB 32 also requires CARB to identify and adopt regulations that will give credit for Discrete Early Actions by January 1, 2010.³⁹⁸ In 2007 CARB developed a list of nine discrete actions to be taken.³⁹⁹ CARB also recommended 44 actions for approval for Early Action credit (which, unlike the Discrete Early Actions, may or may not be regulatory).⁴⁰⁰ CARB estimates that these early actions have the potential to contribute up to 25% of the emissions reductions required to meet the 2020 goal.⁴⁰¹ In February 2008 CARB approved a policy statement encouraging early actions and establishing a procedure for project proponents to submit quantification methods to receive credit for voluntary actions.⁴⁰²

CARB's final approved Scoping Plan supports CCS technology.⁴⁰³ After addressing the carbon reduction benefits of power plants equipped with CCS technology, the Scoping Plan encourages California to support near-term advancement of the technology and ensure an adequate framework is in place to provide credit for CCS projects when appropriate (see the discussion of the CCS Panel *infra* at § 4(c)(2)).⁴⁰⁴ The Scoping Plan includes a brief paragraph regarding California's involvement with the West Coast Regional Carbon Sequestration Partnership, which is a public-private partnership "conducting technology validation field tests, identifying major sources of CO₂ in its territory, assessing the status and cost of technologies for separating CO₂ from process and exhaust gases, and determining the potential for storing captured CO₂ in secure geologic formations."⁴⁰⁵

AB 32 also called for the creation of an Economic and Technology Advancement Advisory Committee (ETAAC) to advise CARB "on activities that will facilitate investment and implementation of technological research and development

³⁹⁷ See CARB Scoping, *supra* note 420, at 5; see also California Environmental Protection Board: Air Resources Board, Mandatory Greenhouse Gas Emissions Reporting,

<http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm> (last visited Nov. 23, 2010).

³⁹⁸ CAL. HEALTH & SAFETY CODE § 38560.5 (West 2010).

³⁹⁹ See CARB, *Early Action Items: Discrete Early Actions*, available at <http://www.arb.ca.gov/cc/ccea/ccea.htm> (last visited Nov. 24, 2010). The nine actions are 1) a low carbon fuel standard; 2) landfill methane capture; 3) reductions from mobile AC; 4) semiconductor reduction; 5) SF6 Reductions; 6) high GWP consumer products; 7) heavy-duty measures; 8) tire pressure program; and 9) shore power.

⁴⁰⁰ CARB, Final Staff Report: Expanded List of Early Action Measures to Reduce Greenhouse Gas Emissions in California Recommended for Board Consideration, at 5 (Oct. 2007), available at <http://www.arb.ca.gov/cc/ccea/ccea.htm> (last visited Nov. 24, 2010).

⁴⁰¹ *Id.* at 2.

⁴⁰² CARB, Policy Statement on Voluntary Actions to Reduce Greenhouse Gas Emissions (February 28, 2008), available at <http://www.arb.ca.gov/cc/scopingplan/voluntary/voluntary.htm> (last visited Nov. 24, 2010).

⁴⁰³ CARB Scoping, *supra* note 420, at 64-65. The Scoping Plan also addresses in-depth potential efforts to reduce CO₂ through terrestrial sequestration (trees) and other natural carbon sinks.

⁴⁰⁴ *Id.*

⁴⁰⁵ *Id.*

opportunities.”⁴⁰⁶ In February 2008 ETAAC released its *Recommendations of the Economic and Technology Advancement Advisory Committee Final Report: Technologies and Policies to Consider for Reducing Greenhouse Gas Emissions in California* (2008 ETAAC Report).⁴⁰⁷ The Report exclusively addresses CCS technology in connection with natural gas and energy technology and promotes CCS as a significant opportunity for emissions reductions.⁴⁰⁸ “Demonstration of carbon capture and sequestration (CCS) in geological formations is a key opportunity for California to benefit from national and international partnerships. Broad commercial deployment of technology for CCS in geological formations faces significant challenges. Nevertheless, it offers a potential opportunity for achieving long term reductions in GHG emissions, especially on a national and global scale.”⁴⁰⁹

The report calls for implementing CCS demonstration projects by 2012 with full commercialization by 2020. It identifies California’s CCS potential as 5.2 gigatons of CO₂ storage in oil and natural gas fields, with potentially even greater capacity in deep saline formations and cites estimates that CCS could represent 15-55% of the cumulative international mitigation effort needed to reduce GHGs by 2100. There are additional benefits from reduction of criteria pollutants like NO_x and sulphur dioxide (SO₂). Implementation of CCS technology was identified as being difficult, with federal and state agencies as well as the private sector listed as the responsible parties for implementing CCS technology.⁴¹⁰

Problems associated with CCS technology include the small size and number of current demonstration projects compared with the scale necessary to mitigate CO₂ emissions. Commercialization of CCS technologies will involve the initial high cost and potential risks of first-generation systems and the need to develop the required infrastructure. Moreover, potential for leakage, both at the general technological level and at potential storage sites, must be identified and mitigation measures created. “Regulatory uncertainties and legal issues regarding property rights and liability are still significant barriers.”⁴¹¹ In addition, there is relatively little experience to date at the federal or state level in combining CO₂ capture, transport, and storage into a fully integrated CCS system.

The 2008 ETAAC Report proposes continuing partnerships like the DOE’s WESTCARB program and taking advantage of international opportunities if

⁴⁰⁶ CARB, *Economic and Technology Advancement Advisory Committee*, available at <http://www.arb.ca.gov/cc/etaac/etaac.htm> (last visited Nov. 24, 2010).

⁴⁰⁷ CALIFORNIA ECONOMIC AND TECHNOLOGY ADVANCEMENT ADVISORY COMMITTEE, RECOMMENDATIONS OF THE ECONOMIC AND TECHNOLOGY ADVANCEMENT ADVISORY COMMITTEE FINAL REPORT: TECHNOLOGIES AND POLICIES TO CONSIDER FOR REDUCING GREENHOUSE GAS EMISSIONS IN CALIFORNIA (2008), available at <http://www.arb.ca.gov/cc/etaac/etaac.htm> (last visited Nov. 24, 2010).

⁴⁰⁸ *Id.* at 5-21 through 5-24; see also Chapter 10, Appendix IV, at 10-51 through 10-56 for a further discussion of CSS technology.

⁴⁰⁹ *Id.* at 5-21.

⁴¹⁰ *Id.* at 5-21.

⁴¹¹ *Id.* at 5-21 through 5-22.

presented.⁴¹² Similarly, California should continue to work with the federal government to address legal, regulatory and safety barriers associated with CCS, especially long-term liability issues like insurance and the appropriate balance between taxpayer involvement and the private sector.⁴¹³ The Report also cites the low likelihood of CCS profitability without a price signal on carbon.⁴¹⁴

The ETAAC's subsequent December, 14, 2009 report, *Advanced Technology to Meet California's Climate Goals: Opportunities, Barriers, and Policy Solutions*, only mentions CCS technology once in reference to programs eligible for federal funding and then references the 2008 ETAAC Report for further information on CCS technology.⁴¹⁵

§ 4(c)(2). Integrated Energy Policy and CCS Panel Reports

In addition to the 2008 Report associated with AB 1925 and the Scoping Plan and various committee reports associated with AB 32, the California Energy Commission (Energy Commission) has produced or contracted for several other reports regarding geologic carbon sequestration in the state.

As required by statute,⁴¹⁶ on December 19, 2009 the Commission released its 2009 Integrated Energy Policy Report (2009 IEPR).⁴¹⁷ The 2009 IEPR claims significant changes in the carbon sequestration field have occurred since the release of the 2008 Report on Carbon Sequestration associated with the 2007 IEPR. For example, the 2009 IEPR claims California technology developers and policy makers have expanded their view of CCS applications from coal and petroleum to include natural gas and refinery gases, the main fossil fuels employed in the State's power plants and industrial facilities.⁴¹⁸ Similarly, new and improved energy reducing solvents for post-combustion closed loop absorption capture systems are being offered and tested, which will decrease the price of CO₂ capture.⁴¹⁹ Developers are also working on competing systems, which will aid the commercial and economic development of CCS technology.⁴²⁰ Since the release of the 2007 IEPR, oxy-combustion CO₂ capture has been tested "at ten times the size of previous pilot units," and pre-combustion CO₂ capture systems are being proposed

⁴¹² *Id.* at 5-22.

⁴¹³ *Id.*

⁴¹⁴ *Id.* at 5-23.

⁴¹⁵ CARB, CALIFORNIA ECONOMIC AND TECHNOLOGY ADVANCEMENT ADVISORY COMMITTEE, ADVANCED TECHNOLOGY TO MEET CALIFORNIA'S CLIMATE GOALS: OPPORTUNITIES, BARRIERS, & POLICY SOLUTIONS, 116 (2009) available at <http://www.arb.ca.gov/cc/etaac/meetings/etaacadvancedtechnologyfinalreport12-14-09.pdf> (last visited Nov. 24, 2010).

⁴¹⁶ CAL. PUB. RES. CODE §25302(a) (West 2010).

⁴¹⁷ CALIFORNIA ENERGY COMMISSION, 2009 INTEGRATED ENERGY POLICY REPORT (December 2009) available at <http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF>. (last visited Nov. 24, 2010).

⁴¹⁸ *Id.* at 108.

⁴¹⁹ *Id.*

⁴²⁰ *Id.*

in commercial plants based on solid fuel gasification.⁴²¹

The 2009 IEPR also includes recent Department of Energy (DOE) activities that may affect CCS in the state. The IEPR Report states:

The U.S. Department of Energy (DOE) recently solicited proposals for large-scale industrial CCS projects at facilities fueled chiefly by noncoal energy; it is poised to award more than \$1.3 billion in project co-funding authorized by the ARRA [American Recovery and Reinvestment Act] of 2009. Further, DOE has added funds to its cooperative agreement with the Energy Commission for the West Coast Regional Carbon Sequestration Partnership (WESTCARB; a public-private research collaborative involving more than 80 organizations) to work with PG&E to conduct an engineering-economic evaluation of CCS at natural gas combined cycle plants in California. WESTCARB also continues to work with the California Geological Survey and industry partners to characterize California deep saline formations suitable for commercial-scale CO₂ storage; two CO₂ storage field tests in the Central Valley are planned.⁴²²

In addition to physical projects and technologies, the 2009 IEPR stresses the need for California to clarify and solidify a legal/regulatory regime to accommodate and encourage CCS development. The 2009 IEPR identifies several key regulatory issues. First, the report calls for California to join other states in establishing rules regarding the ownership of and title to the “pore space” the captured CO₂ is to be stored in.⁴²³ These regulations should address ownership of the pore space, ability to transfer pore space rights and dominance of those right relative to surface and mineral rights, access procedures for adjoining pore properties, and potential long-term liability issues.⁴²⁴ Also needing attention are the procedure to determine which permitted EOR operations may become long-term CO₂ projects and the responsibilities and jurisdiction of the California Environmental Quality Act for: 1) siting power plants with CCS technology, pipelines, and offsite geologic storage of CO₂; 2) monitoring, reporting, and remediation of stored CO₂; and 3) rules for offshore (sub-seabed) CO₂ projects.⁴²⁵

In response to the 2009 IEPR, a Carbon Capture and Storage Review Panel (CCS Panel) was formed in April 2010. The CCS Panel is tasked to: 1) frame specific policies addressing the role of CCS in meeting the state's energy needs and greenhouse gas reduction goals; 2) review CCS policy frameworks used elsewhere, and identify gaps, alternatives, and applicability in California; and 3) develop

⁴²¹ *Id.* at 108-09.

⁴²² *Id.* at 109.

⁴²³ *Id.*

⁴²⁴ *Id.* at 109-10.

⁴²⁵ *Id.*

specific recommendations on CCS to be reported to the California Energy Commission, Public Utilities Commission, and CARB by November 30, 2010.⁴²⁶ On December 13, 2010, the CCS Panel released a report titled *Draft Recommendations by the California Carbon Capture and Storage Review Panel* (CCS Recommendations).⁴²⁷ The CCS Recommendations identify CCS as an important mitigation strategy to help California meet the AB 32 GHG reduction goals and suggest measures California should adopt to encourage CCS and make it a profitable venture in California.

If CCS is to play a role in achieving California's greenhouse gas reduction goals, a clear and consistent regulatory and policy framework must be established. The framework should clearly establish the roles and authorities of the involved state agencies, facilitate and streamline permitting processes, and serve the public's interest in assuring climate change mitigation goals are met while protecting the environment and human health and safety.

A statutory or regulatory framework for CCS must be clear, transparent, flexible and adaptable. There is a need for a clearly articulated state policy which recognizes the value of CCS technology as [sic.] marketable commodity and as a GHG reduction strategy. Lastly, there must be clear rules on permitting and regulating CCS projects. Consistent reporting protocols should be established for monitoring, measurement and verification of the volume of GHG emissions sequestered, and a GHG accounting method should be established that gives carbon credits to CCS development projects which help industry satisfy their AB 32 obligations.⁴²⁸

The CCS Recommendations conclude that CCS is beneficial to California and encourage measures to facilitate rapid yet safe development and deployment of CCS. Going a step further than the ETaac recommendation of CCS as a long-term possibility, the CCS Recommendations call on CARB to set a short-term goal to expedite the use of CCS, before 2020 if possible.⁴²⁹ The main recommendations of the report are:

1. The State should clearly identify CCS as a measure that can reduce carbon and that allows carbon credits under a state-administered cap-and-trade

⁴²⁶ CARB. *California Carbon Capture and Storage*, http://www.climatechange.ca.gov/carbon_capture_review_panel/index.html (last visited Nov. 24, 2010).

⁴²⁷ CARB CCS REVIEW PANEL, DRAFT RECOMMENDATIONS BY THE CALIFORNIA CARBON CAPTURE AND STORAGE REVIEW PANEL, December 2010, available at http://www.climatechange.ca.gov/carbon_capture_review_panel/meetings/2010-12-15/2010-12-13_Draft_Recommendations_by_the_California_Carbon_Capture_and_Storage_Review_Panel.pdf (last visited Dec. 20, 2010) [hereinafter CCS RECOMMENDATIONS].

⁴²⁸ CCS RECOMMENDATIONS, *supra* note 454, at 1.

⁴²⁹ *Id.* at 7.

program. To that end, the ARB should develop GHG reporting protocols for CCS projects.

2. The State should consider legislation authorizing the use of eminent domain for CO₂ pipelines that are not owned or operated by public utilities. The legislation should clarify the ownership of "pore space" and ensure that property owners are justly compensated for the use of their land for CCS development. Alternately, the State should establish a process by which the rights of property owners are fairly adjudicated.
3. The State should consider legislation that identifies either the CPUC [California Public Utilities Commission] or the State Fire Marshall as the lead agency for regulating CO₂ pipelines.
4. The State should identify a lead agency for administering post-closure operations, and for establishing monitoring, measurement and verification (MMV) requirements for permitting CCS projects.
5. The State should consider legislation establishing a fee-based fund structure to be used for long-term stewardship.
6. The [CCS] Panel endorses the need for a well thought-out and well-funded public outreach program to ensure that the risks and benefits of CCS technology are effectively communicated to the public.
7. The State should establish and administer a program to insure against the long-term risk of irregular CO₂ behavior in the reservoir, in concert with the federal government.
8. The State should consider legislation designating the Energy Commission as the lead [agency for] permitting projects *[sic.]* for all CCS projects (both stand-alone and retrofit projects).
9. The CEC should consult with the responsible permitting agencies in carrying out its responsibilities. Specifically, the CEC should consult with the Division of Oil, Gas and Geothermal Resources (DOGGR) for its technical expertise associated with oil and gas development and incorporate the DOGGR requirements into the CEC permit process.
10. The State of California should evaluate the pending EPA regulations and determine whether and who should seek "primacy" for permitting CCS wells.
11. The State should establish one set of performance and remediation standards for geologic storage projects that demonstrate, with a high degree of confidence, 99 percent retention over a thousand years. These standards should measure the quantity and permanence of CO₂ sequestered.
12. Methodology to stimulate early mover CCS projects should be considered.⁴³⁰

Specific recommendations for each of these measures are outlined in the full report, including recommendations to treat CO₂ as a commodity rather than a pollutant or

⁴³⁰ *Id.* at 3-4.

hazardous liquid,⁴³¹ conduct further studies on pore space ownership,⁴³² develop a trust fund for long-term monitoring,⁴³³ push for a federal system governing long-term liability,⁴³⁴ authorize eminent domain for CO₂ pipelines,⁴³⁵ and provide funding mechanisms and public education to promote CCS development in California.⁴³⁶

With the December 16, 2010, CARB vote approving a cap-and-trade program that will be the largest of any in the United States, California moves a step closer to placing a price on carbon emissions.⁴³⁷ The combination of the favorable CCS Recommendations and the financial incentives provided by the cap-and-trade program strengthen California's potential as a leader for CCS.

§ 4(c)(3). Geologic Carbon Sequestration Potential in California

Another pertinent publication released by the California Energy Commission in December 2006 is *An Overview of Geologic Carbon Sequestration Potential in California* (Overview).⁴³⁸ The Overview is a preliminary assessment by the California Geological Survey (CGS) of geologic carbon sequestration potential in California. This assessment was part of the West Coast Regional Carbon Sequestration Partnership and "involved identifying and characterizing porous and permeable rock formations and defining areas within the state's sedimentary basins that may be geologically suitable for carbon sequestration in saline aquifers or producing or abandoned oil and gas reservoirs."⁴³⁹

The Overview examines CCS technology and the WESTCARB project; experimental projects to complete CCS goals; and the results of California's various experiments. The Overview concludes:

A preliminary screening of California's sedimentary basins indicates that at least 27 basins possess varying potential for CO₂ sequestration. These basins comprise an aggregate area of more than 98,420 km² (38,000 sq. mi.)

....
Currently, the most promising basins for potential CO₂ sequestration include the San Joaquin, Sacramento, Ventura, Los Angeles, and Eel

⁴³¹ *Id.* at 9.

⁴³² *Id.* at 10-11.

⁴³³ *Id.* at 13-14.

⁴³⁴ *Id.*

⁴³⁵ *Id.* at 15.

⁴³⁶ *Id.* at 16-18.

⁴³⁷ See Margot Roosevelt, *California Air Regulators Approve Carbon-Trading Plan*, L.A. TIMES (Dec. 17, 2010), available at <http://www.latimes.com/news/local/la-me-1217-climate-cap-trade-20101217,0,562122.story> (last visited Dec. 20, 2010).

⁴³⁸ California Geological Survey, AN OVERVIEW OF GEOLOGIC CARBON SEQUESTRATION POTENTIAL IN CALIFORNIA (Dec. 2006), available at <http://www.consrv.ca.gov/CGS/News/CEC-500-2006-0882.pdf> (last visited Nov. 24, 2010).

⁴³⁹ *Id.* at 1.

River basins. Smaller marine basins such as the Salinas, La Honda, Cuyama, Livermore, Orinda, and Sonoma basins are also promising but more restricted in terms of size and available geological information. Several terrestrial basins, including the large Salton Trough, may present some opportunities for CO₂ sequestration and cannot be excluded from consideration given the limited currently available information.

....

Preliminary estimates of CO₂ storage capacity of the ten largest basins identified in this assessment have placed the storage capacity of saline aquifers between 146–840 gigatonnes of carbon dioxide (Gt CO₂) depending on the varying degrees of dissolved phase and separate-phase pore volume storage. Additional geological information and characterization of these basins, including detailed, formation-specific mapping will be required before their specific potential for CO₂ sequestration can be more accurately assessed.⁴⁴⁰

§ 4(d) Colorado's CCS Efforts

Colorado had eleven coal mines in 2009; three were surface mines and eight were underground mines. Production was a little over 28 million tons, which is a little under five percent of the coal produced in the western states.⁴⁴¹ Colorado coal production decreased by almost nine percent between 2006 and 2009.⁴⁴² Colorado has fourteen coal-fired power plants that have thirty-three units with a total capacity of 5,308 MWs.⁴⁴³ Colorado has encouraged CCS and clean coal technologies, and in 2009, a site near Craig, Colorado was awarded a demonstration CCS project by the federal government.⁴⁴⁴ However, recent actions by the Colorado legislature reduce incentives for CCS by essentially requiring coal plants to be replaced with natural gas plants.⁴⁴⁵ On April 19, 2010, H.B. 1365 was signed by the governor. It

⁴⁴⁰ *Id.* at 55.

⁴⁴¹ EIA Mine Type, *supra* note 375.

⁴⁴² Source Watch, *Colorado and Coal*, available at http://www.sourcewatch.org/index.php?title=Colorado_and_coal#Existing_coal_plants (last visited Nov. 30, 2010).

⁴⁴³ Source Watch, *Category: Existing Coal Plants in Colorado*, available at http://www.sourcewatch.org/index.php?title=Category:Existing_coal_plants_in_Colorado (last visited Nov. 29, 2010). The plants are: Arapahoe Station, Cameo Station (projected to be shut down by 2010), Cherokee Station, Clark Station, Comanche Generating Station, Craig Station, Hayden Station, Martin Drake Power Plant, Nucla Station, Pawnee Station, Rawhide Energy Station, Ray Nixon Power Plant, Trigen Colorado Steam Plant, Valmont Station (has proposed shutting down one unit), and Yampa Project. (Although this is fifteen plants, it is the list provided by Source Watch, which lists the number of plants in Colorado as fourteen.)

⁴⁴⁴ See Tri-State, *Tri-State to Participate in \$4.8 Million Carbon Sequestration Project*, available at <http://www.tristategt.org/NewsCenter/NewsItems/Carbon-sequestration-project.cfm> (last visited Nov. 30, 2010).

⁴⁴⁵ COLO. REV. STAT. ANN. § 40-3.2-204 (West 2010); *see also Colorado Gas Bill Touted as Model for States to Meet EPA Air Rules*, XXVII ENVTL. POL'Y ALERT (Inside EPA) 7:38 (Apr. 7, 2010).

requires utilities to submit an emissions reduction plan that requires Xcel, the state's largest utility to reduce nitrogen dioxide emissions up to eighty percent from 900 megawatts or 50 percent of the utility's generating capacity, whichever is less. This will necessitate converting coal-fired power plants to natural gas or other low-emission electricity sources.⁴⁴⁶ Colorado also enacted legislation on March 22, 2010, to increase the percentage of renewable energy from investor-owned and certain other utilities from twenty to thirty percent.⁴⁴⁷ These laws will reduce the need for CCS.

§ 4(d)(1). Research Support for Carbon Sequestration and IGCC Technology.

The Colorado legislature directed the Colorado Department of Public Health and Environment to administer the following research grants regarding CCS or IGCC technology.⁴⁴⁸ The Colorado School of Mines was to receive \$50,000 to conduct CCS research on geologic carbon sequestration.⁴⁴⁹ The University of Colorado was "to conduct research on the emerging international and domestic markets in greenhouse gas emissions and to conduct research on private firms in various economic sectors that are reducing emissions of greenhouse gases."⁴⁵⁰ As required by statute, the recipient institutions reported the results of their research to the Agriculture Committees of the Colorado House and Senate on March 15, 2007.⁴⁵¹ After synthesizing their findings, the report made numerous recommendations including the need to promote state policies to enable CCS in all potential sinks, including geological targets, and stimulate the growth of a new CCS industry in the state by providing incentives for companies with the appropriate skills to explore new business opportunities as well as research support.⁴⁵²

This report was accompanied by the Colorado Climate Action Plan (Action Plan), which outlined the Colorado global warming mitigation strategy.⁴⁵³ The Action Plan recognizes CCS technology as a potential means to balance the economic benefit of Colorado's coal production with the need for cleaner, low-carbon fuels.⁴⁵⁴ To ensure that geologic sequestration can begin along with the deployment of IGCC technologies, the Departments of Natural Resources and Public Health and the Environment will work to expeditiously resolve the hurdles to geologic

⁴⁴⁶ Tripp Baltz, *State Law Requires Utilities to Reduce Emissions from Coal-Fired Power Plants*, 41 Env't Rep. (BNA) 912 (Apr. 23, 2010).

⁴⁴⁷ COLO. REV. STAT. ANN. § 40-2-124(E) (2010 West); *see also* Colorado Bill Increases Renewables Standard, 41 Env't Rep. (BNA) 704 (Mar. 26, 2010).

⁴⁴⁸ COLO. REV. STAT. ANN. § 25-1-1303(1) (2006).

⁴⁴⁹ COLO. REV. STAT. ANN. § 25-1-1303(2)(b) (2006).

⁴⁵⁰ COLO. REV. STAT. ANN. § 25-1-1303(2)(c) (2009).

⁴⁵¹ COLO. REV. STAT. ANN. § 25-1-1303(3) (2009).

⁴⁵² Rich Conant *et al.*, *The Colorado Climate Change Markets Act: Report to the Colorado Legislature*, (March 15, 2007), available at ees.colorado.edu/CCMA.pdf (last visited Nov. 29, 2010).

⁴⁵³ *See generally*, OFFICE OF GOVERNOR BILL RITTER JR., COLORADO CLIMATE ACTION PLAN: A STRATEGY TO ADDRESS GLOBAL WARMING (2007), available at

<http://www.colorado.gov/cs/Satellite/GovRitter/GOVR/1251568200609> (last visited Nov. 29, 2010).

⁴⁵⁴ *Id.* at 18.

sequestration, including identifying potential sequestration sites in Colorado and developing an appropriate regulatory framework.⁴⁵⁵

§ 4(d)(2). Clean Energy Development Authority.

Colorado created a Clean Energy Development Authority (Authority) that is empowered to facilitate the production and consumption of clean energy; increase the transmission and use of clean energy by financing and refinancing projects located within or outside the state for the production, transportation, transmission, and storage of clean energy, including pipelines, and related supporting infrastructure and interests therein; and facilitate the efficient use of energy.⁴⁵⁶ One of the Authority's mandates is to "convene qualified task forces to develop . . . official recommendations for the general assembly regarding the types of clean energy projects that the authority should finance, refinance, or otherwise support."⁴⁵⁷ The Authority is mandated to convene a task force to assess whether IGCC facilities, or other clean coal technologies with the potential for substantial sequestration of carbon emissions, should be considered clean energy projects that the authority may finance, refinance, or otherwise support, and, if so, the nature and extent of any restrictions, including, but not limited to, specific CO₂ emissions sequestration requirements that such projects should satisfy as a prerequisite to authority support.⁴⁵⁸

In 2009, the Authority published a report on the infrastructure needed for renewable energy development—the REDI report. The goal of the report was to outline methods for Colorado to meet its goal of a twenty percent reduction in CO₂ emissions by 2020 (the 20/20 goal). (This goal has now been increased to thirty percent reductions as discussed above in § 4(d).) The REDI report explored ways to reach the 20/20 goal, but with the caveat that "proposed actions must not interfere with electric system reliability and should minimize financial impacts on customers and utilities."⁴⁵⁹ In modeling the most economically efficient pathways to meet the

⁴⁵⁵ *Id.* at 19. A cursory search of the Colorado Climate Action Plan suggests there have been no official press releases, updates, or other actions regarding the plan since its release in 2007. However, significant action has been taken towards meeting Colorado's goal of emission reductions.

⁴⁵⁶ COLO. REV. STAT. ANN. § 40-9.7-102(2)(a)-(c) (2008).

⁴⁵⁷ COLO. REV. STAT. ANN. § 40-9.7-106(1)(c)(I) (2008). The authority shall convene the task forces as soon as the authority determines that it has received sufficient moneys from gifts, grants, donations, or project fees to adequately fund the activities of the task forces.

⁴⁵⁸ COLO. REV. STAT. ANN. §40-9.7-106(1)(c)(I)(B) (2007). This provision excludes IGCC projects described in section 40-2-123 (2)(b) (I) that are specifically defined as clean energy pursuant to section 40-9.7-103(5) (g). These provisions speak to IGCC facilities under review for support from of the Colorado Utilities Commission as new energy alternatives (discussed below).

⁴⁵⁹ Clean Energy Development Authority, *Renewable Energy Development Infrastructure: Connecting Colorado's Renewable Resources to the Markets in a Carbon-Constrained Electricity Sector*, at 3 (2009) [hereinafter REDI Report], available at http://rechargecolorado.com/index.php/programs_overview/utilities_and_transmission/clean_energy_development_authority/ (last visited Nov. 30, 2010).

20/20 goal, the REDI report did not have the funds to include CCS in its models. The report pointed out that “[c]oal will likely will [sic.] have a continued, but perhaps diminishing, role as an important source of baseload power generation [in Colorado] Should Colorado decide to implement the 20x20 goal, it is unlikely that new coal-fired generation would be added to the energy mix unless the plants contain major advances in carbon capture and storage (CCS).”⁴⁶⁰ Although the report seemed to discount CCS as a methodology to reach Colorado’s 20/20 goal, it did identify CCS as a potential “game changer” if the technology advanced to enable commercial application of CCS within the 2020 timeframe.

A number of emerging technologies and policy developments could change whatever path is selected to reach the 20x20 goal. We highlighted the following potential “game-changers”: electrification of the transportation sector, the potential for Smart Grid, increasing emphasis on distributed generation, greater penetration of photovoltaics, *breakthroughs in carbon capture and storage technologies* [emphasis added], the potential impact of shale gas on the electricity sector, the potential for new transmission technologies, feed in tariffs, and a national renewable electricity standard. . . . More than \$3 billion of ARRA [American Recovery and Reinvestment Act] funds are dedicated to the advancement of CCS technology. Successful commercialization of CCS holds promise to reduce CO₂. However, the pathway to success with CCS may take many years.⁴⁶¹

Acting on a request from Governor Ritter, the Department of Natural Resources organized a CCS Task Force, which has been meeting monthly since March 2010.⁴⁶² The 13-member task force is made up of legislators, agency officials and stakeholders, and is tasked to come up with legal and regulatory recommendations for the 2011 legislative session to promote successful geologic carbon sequestration in Colorado.⁴⁶³ As of winter 2010, no report had yet been issued from the task force.

Thus, it appears that although Colorado has a significant interest in CCS, from both a development and application perspective, the most recent legislative actions and government focus are more supportive of renewable resources and phasing out coal. While Colorado would welcome a CCS breakthrough, it seems to be relying on the federal government to promote and fund such a breakthrough rather than

⁴⁶⁰ *Id.* at 21.

⁴⁶¹ *Id.* at 31, 34.

⁴⁶² See *State Task Force to Target Carbon Capture and Sequestration*, COLORADO ENERGY NEWS (March 11, 2010), available at <http://coloradoenergynews.com/2010/03/state-task-force-to-target-carbon-capture-sequestration/> (last visited Nov. 30, 2010).

⁴⁶³ Colo. Dep’t of Nat’l Res., *Homepage*, <http://www.dnr.state.co.us/> (last visited Nov. 30, 2010).

focusing its own funding sources and legislative initiatives on developing CCS.⁴⁶⁴ However, with the formation of the CCS task force, the potential for new IGCC facilities, and experimental CCS projects taking place in Colorado, significant technology advancements could give CCS a place in Colorado's energy future.

§ 4(d)(3). New Energy Technologies.

The Colorado legislature recently empowered Colorado's Utilities Commission to include CCS and related technology in their permitting of power producing facilities.⁴⁶⁵ Under Colorado law, the Colorado Utilities Commission (Commission), may "give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities."⁴⁶⁶ The Commission shall "consider proposals by Colorado electric utilities to propose, fund, and construct IGCC generation facilities to demonstrate the feasibility of this clean coal technology with the use of western coal and with carbon dioxide capture and sequestration."⁴⁶⁷ "An IGCC facility may also use natural gas, in addition to gasified coal, as a fuel in the combustion turbine."⁴⁶⁸

To be considered by the Commission, potential IGCC facilities must demonstrate electricity-generating IGCC technology using Colorado or western coal; not exceed 350 megawatts of nameplate capacity, unless a larger size is needed to take advantage of financial incentives or cost sharing opportunities; demonstrate the capture and sequestration of a portion of the project's CO₂ emissions; include methods and procedures to monitor the fate of the CO₂ captured and sequestered from the facility; and be located in Colorado.⁴⁶⁹

A utility may submit an application for a certificate of public convenience and necessity⁴⁷⁰ and cost recovery for one IGCC project.⁴⁷¹ This application must include the reasons why the utility should be exempt from the Commission's competitive resource acquisition rules.⁴⁷² A utility must also include information about the proposed facility's economic and technical feasibility; near term and future commercial development potential; projected efficiency; projected cost, incremental average rate impact, and form of rate recovery; and any other relevant

⁴⁶⁴ See, e.g., M.J. Clark, *Freudenthal, Fellow Govs ask Obama to Support Clean Coal*, WYOMING BUSINESS REPORT, (Feb. 23, 2009), available at <http://www.wyomingbusinessreport.com/article.asp?id=98784> (last visited Nov. 30, 2010).

⁴⁶⁵ COLO. REV. STAT. ANN. § 40-2-123(1)(b) (2009).

⁴⁶⁶ COLO. REV. STAT. ANN. § 40-2-123(1)(a) (2009).

⁴⁶⁷ COLO. REV. STAT. ANN. § 40-2-123(2)(a) (West 2010).

⁴⁶⁸ COLO. REV. STAT. ANN. § 40-2-123(2)(b)(II) (West 2010).

⁴⁶⁹ COLO. REV. STAT. ANN. §40-2-123(2)(b)(I)(A)-(E) (West 2010).

⁴⁷⁰ A certificate for public convenience and necessity is the exclusive agreement between the utility and Commission defining the rights and obligations of the parties. 64 Am. Jur. 2d Public Utilities § 158 (2009).

⁴⁷¹ COLO. REV. STAT. ANN. § 40-2-123(2)(c) (West 2010).

⁴⁷² *Id.* Colorado's competitive resource acquisitions are found at 4 C.C.R. § 723 -3610 *et seq.* (2008).

information.⁴⁷³ To address environmental concerns, an application must also provide information on the project's water savings, emission rates and other environmental benefits; environmental and public safety impacts; the portion of the project's emissions captured and sequestered; and an analysis of the economic implications and feasibility of different levels of CCS.⁴⁷⁴

The Commission shall provide the public an opportunity to comment and hold an evidentiary hearing on a utility's application.⁴⁷⁵ If the Commission determines the project is in the public's interest, it may grant a certificate for public convenience and necessity instead of requiring the project to follow its competitive resource acquisition rules.⁴⁷⁶ If approved, the IGCC plant shall constitute an appropriate component of a utility's resource plan. If the Commission approves a project, a declaratory order for cost recovery⁴⁷⁷ shall provide, *inter alia*, that utilities are entitled to fully recover from their retail customers through rate adjustments costs for planning, development, constructing, and operating the IGCC plant, net any federal or state funds the project receives.⁴⁷⁸ Similarly, if an IGCC plant's wholesale market is regulated by the Federal Energy Regulatory Commission (FERC), the Commission "shall determine whether to assign a portion of the IGCC project's cost of service to be recovered from the public utility's wholesale customers."⁴⁷⁹ "All revenues a public utility receives from its wholesale customers for the IGCC project's costs shall be credited as an offset to the IGCC project's costs charged to the public utility's retail customers."⁴⁸⁰ Approved facilities are entitled to recover the full life-cycle capital and operating costs, "unless the Commission finds such costs to be imprudent after fully taking into account the technical and financial challenges and uncertainties associated with the project."⁴⁸¹ Like other power generating facilities, IGCC plants may recover, through an adjustment clause, for power purchased during planned and unplanned power outages during⁴⁸² and after the initial start up and testing period.⁴⁸³ "In structuring the adjustment clause, the utility's return on investment in an IGCC project from time to time shall be limited to the utility's most recent commission-approved return on investment in other utility generation facilities."⁴⁸⁴

⁴⁷³ COLO. REV. STAT. ANN. § 40-2-123(2)(c)(I)-(IV) (West 2010).

⁴⁷⁴ COLO. REV. STAT. ANN. § 40-2-123(2)(d)(I)-(IV) (West 2010).

⁴⁷⁵ COLO. REV. STAT. ANN. § 40-2-123(2)(e)(I) (West 2010).

⁴⁷⁶ *Id.*

⁴⁷⁷ COLO. REV. STAT. ANN. § 40-2-123(2)(e)(I) (West 2010).

⁴⁷⁸ COLO. REV. STAT. ANN. § 40-2-123(2)(f)(I) (West 2010). Provision includes additional cost recovery options and limitations.

⁴⁷⁹ COLO. REV. STAT. ANN. § 40-2-123(2)(f)(II) (West 2010). *See also* COLO. REV. STAT. ANN. § 40-2-123(2)(f)(III), (IV) (West 2010) (additional cost recovery from FERC regulated entities).

⁴⁸⁰ COLO. REV. STAT. ANN. § 40-2-123(2)(f)(V) (West 2010).

⁴⁸¹ COLO. REV. STAT. ANN. § 40-2-123(2)(g) (West 2010).

⁴⁸² *Id.*

⁴⁸³ COLO. REV. STAT. ANN. § 40-2-123(2)(h) (West 2010).

⁴⁸⁴ COLO. REV. STAT. ANN. § 40-2-123(2)(g) (West 2010).

IGCC plants are required to report on the cost and performance of the project once it is commercially operating.⁴⁸⁵ The commission shall then conduct an investigation and public hearing to determine if shutting down, decommissioning or repowering the IGCC plant is in the public's best interest. The utility sponsoring the IGCC project is entitled to full recovery of costs incurred in a shutdown, repowering or decommissioning of the project.⁴⁸⁶

The Colorado legislature has included several provisions to make IGCC projects more attractive to public utilities. For example, to reduce costs to Colorado consumers "the department of public health and environment [sic], the governor's office of economic development [sic], and the governor's energy office [sic] may provide public utilities with reasonable assistance in seeking and obtaining financial and other support and sponsorship for a project" from the U.S. Congress, the Department of Energy, and other appropriate federal and state agencies and institutions.⁴⁸⁷ A utility must submit a copy of its IGCC proposal to the appropriate agencies, and the Governor's Energy Office will oversee and distribute any applicable funds for studying or developing IGCC projects.⁴⁸⁸ Utilities may also seek financial support from Colorado's Clean Energy Development Fund under section 24-22-118 of the Colorado Revised Statutes.⁴⁸⁹ Additionally, public utilities "may develop, construct, or own an IGCC facility through a special purpose entity or other affiliated partnership or corporation."⁴⁹⁰

In November 2007, the Public Service Company of Colorado (Xcel Energy) included plans for an IGCC facility in its Electric Resource Plan. Initial plans projected a start date in 2010, but Public Service Company of Colorado has not yet filed an application with the Public Utilities Commission, making the plant's projected completion in 2016 doubtful.⁴⁹¹ There is no mention of the Colorado IGCC plant in Xcel's annual reports since 2007. Nevertheless, the REDI Report bases its CO₂ emissions projections on the assumption that an IGCC plant will be operational in Colorado by 2020.⁴⁹²

§ 4(e). Idaho's CCS Efforts

⁴⁸⁵ COLO. REV. STAT. ANN. § 40-2-123(2)(h) (West 2010).

⁴⁸⁶ *Id.*

⁴⁸⁷ COLO. REV. STAT. ANN. § 40-2-123(2)(j) (West 2010).

⁴⁸⁸ *Id. See also* COLO. REV. STAT. ANN. § 24-38.5-102(n) (West 2010) (Governor's Energy Office shall "[p]rovide public utilities with reasonable assistance, if requested, in seeking and obtaining support and sponsorship for an IGCC project as defined in [40-2-123](#) (2) (b) (I), C.R.S., and manage and distribute to the utility some or all of any funds provided by the state or by the United States government to the state for purposes of study or development of an IGCC project as specified in section [40-2-123](#)(2)(j), C.R.S.).

⁴⁸⁹ COLO. REV. STAT. ANN. § 40-2-123(2)(k) (West 2010).

⁴⁹⁰ COLO. REV. STAT. ANN. § 40-2-123(2)(l) (West 2010).

⁴⁹¹ *See* REDI Report, *supra* note 487, at 21.

⁴⁹² *Id.* at 10, 21.

Idaho is not a coal producing state,⁴⁹³ and it has no coal-fired power plants,⁴⁹⁴ although it obtains forty-two percent of its base load power from coal-fired generators located in other states.⁴⁹⁵ Idaho has worked to prevent coal-burning power plants from being sited in the state. The state Department of Environmental Quality opted not to participate in EPA's cap-and-trade program for mercury emissions in order to prevent new coal-fired power plants from seeking to locate in Idaho.⁴⁹⁶ In 2002 the Idaho Legislature created a Carbon Sequestration Advisory Committee to work to develop a program to encourage biologic sequestration.⁴⁹⁷ However, the state does not appear to have enacted any legislation dealing with geologic sequestration.

In February 2009 Idaho's Department of Environmental Quality (IDEQ) issued an air permit for a project being developed by Southeast Idaho Energy, LLC that is designed to gasify 2,000 to 2,300 tons of coal and petcoke a day to produce synthesis gas in order to produce ammonia, which will be used to produce nitrogen-based fertilizer. The permit did not include any limit on CO₂ emissions. The Sierra Club and the Idaho Conservation League sued to force the company to control CO₂. A settlement was reached that requires the plant to capture and sequester fifty-eight percent of the plant's CO₂ emissions, which will reduce the emissions to levels found in natural gas-fired fertilizer plants. IDEQ modified the air permit to incorporate the negotiated CO₂ limits while denying its applicability to other facilities, because CO₂ is not considered to be an air pollutant under Idaho law. The project is projected to require four years for completion, and, if successful, the requirements imposed by the settlement could become best available control technology (BACT) for other new or modified facilities.⁴⁹⁸ Recent EPA guidance has indicated that CCS could be considered BACT on a case-by-case basis, if it can pass the necessary analysis to show it is a feasible option.⁴⁹⁹ Idaho Representative Mike Simpson has vowed to curtail EPA's reach, singling out EPA regulation of GHGs as an agency overreach. Rep. Simpson is projected to head the Interior and Environment subcommittee of the House Appropriations Committee.⁵⁰⁰

⁴⁹³ EIA Mine Type, *supra* note 375.

⁴⁹⁴ U.S. Dept. of Energy, *Electric Power and Renewable Energy in Idaho*, available at <http://appsl.eere.energy.gov/states/electricity.cfm/state=ID> (last visited Dec. 1, 2010).

⁴⁹⁵ Idaho Office of Energy Resources, *Baseload Power*, available at <http://www.energy.idaho.gov/baseload.htm> (last visited Dec. 1, 2010)).

⁴⁹⁶ See Leslie Bradshaw, *Keep Idaho Out of Mercury Cap and Trade Plan*, IDAHO MOUNTAIN EXPRESS, Jan. 19, 2007.

⁴⁹⁷ I.C. §§ 22-5201 to 22-5206.

⁴⁹⁸ Svend Brandt-Erichsen, *First State Air Permit with Enforceable CO₂ Limits Issued for Idaho Coal-Fueled Fertilizer Plant 2*, Marten Law Group, available at <http://www.martenlaw.com/news/?20091214-permit-with-enforceable-co2-limits> (last visited Aug. 6, 2010); see also Refined Energy Holdings, *Power County Advanced Energy Center*, available at <http://www.rehinc.com/PCAEC.aspx> (last visited Dec. 3, 2010).

⁴⁹⁹ See EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases* (Nov. 2010), available at <http://www.epa.gov/nsr/ghgpermitting.html> (last visited Dec. 3, 2010).

⁵⁰⁰ See Erika Bolstad, *Rep. Simpson Gears Up to Take On EPA*, IDAHO STATESMAN (Dec. 1, 2010), available at <http://www.idahostatesman.com/2010/12/01/1438364/simpson-gears-up-to-take-on-epa.html> (last visited Dec. 3, 2010).

§ 4(f). Kansas's CCS Efforts

In 2009, Kansas had one surface mine that produced 0.017% of the nation's coal. This was down from two surface mines in 2008.⁵⁰¹ However, according to available estimates, Kansas uses coal to produce about 71% of the electricity generated in the state. Kansas has sixteen coal-fired power plants with a total capacity of 5,473 MW and is 23rd in the nation in coal-fired electric power production.⁵⁰²

The expansion of coal-burning power plant capacity has been very controversial in Kansas, spawning lawsuits, affecting political elections, and costing the state's top environmental protection employee his job.⁵⁰³ The ramifications of the political and legal struggle are still playing out, as Sunflower Electric Power awaits approval of a permit to expand its operations with a new coal-fired power plant. If the permit is approved before January 2, 2011, Sunflower will not be subject to EPA's new monitoring requirements for GHGs. In order for this to occur, the public comment period has been limited to thirty days. However, the EPA has warned the process must be fair:

If [the department of] Kansas Health and Environment recommends that Sunflower be permitted before Jan. 2, EPA will review this initial decision by asking three important questions:

First, does the Kansas permit include public-health protection standards required by sound science and federal law?

Second, did Kansas operate all parts of its permitting process as required by the Clean Air Act?

And finally, does a Sunflower permit satisfy public confidence in the impartiality and transparency of Kansas' system of safeguarding air quality?

Kansas' air permitting law gives all three branches of state government important work, and also invites the people of the state to participate. That's why EPA must scrutinize not just the language of

⁵⁰¹ EIA Mine Type, *supra* note 375.

⁵⁰² Source Watch, *Kansas and Coal*, http://www.sourcewatch.org/index.php?title=Kansas_and_coal (last visited Dec. 3, 2010).

⁵⁰³ *Id.*

any Sunflower permit, but the whole state decision-making process that produced a permit.⁵⁰⁴

Sunflower claims it will capture and use some CO₂ emissions in an Integrated Bioenergy Center that grows algae, but it has no current geologic storage proposals.⁵⁰⁵

In 2007, Kansas enacted H.B. 2419 that directs the Kansas Corporate Commission to issue regulations for carbon sequestration and to create tax incentives to encourage carbon sequestration projects. This legislation, known as the Carbon Dioxide Reduction Act, was amended in 2010 by H.B. 2418.⁵⁰⁶ The Act instructs the state Corporation Commission to develop rules governing the injection of CO₂ for either EOR or CCS.⁵⁰⁷ In February of 2010, the rules were approved and adopted into the Kansas Administrative Regulations.⁵⁰⁸

The Commission also has power to collect fees and impose any necessary requirements for monitoring, permitting, and inspection. The fees will go to a fund specifically for CO₂ injection and storage.⁵⁰⁹ Companies who receive permits must provide annual proof to the Commission of sufficient finances to cover closure costs.⁵¹⁰ The Act disclaims liability for CO₂ storage and maintenance except through legitimate claims under the Kansas Tort Claims Act. Finally, the Act preserves emergency remediation powers for the Commission.⁵¹¹ The Commission is also granted powers to enforce violations with fines of up to \$10,000 per incident, provide hearings and administer orders subject to judicial review, and conduct inspections.⁵¹²

In conjunction with the Carbon Dioxide Reduction Act, the Kansas legislature also passed statutes to give property and income tax breaks for CCS. Kansas Statute 79-233 provides a five-year property tax exemption for “[a]ny carbon dioxide capture, sequestration or utilization property; and any electric generation unit which captures and sequesters all carbon dioxide and other emissions.”⁵¹³ In order to qualify for the exemption, the property should include any of the following:

⁵⁰⁴ Karl Brooks, EPA Administrator, Region 7, *EPA Leader Pledges Fair Decision on Power Plant*, LJWORLD.COM, Nov. 27, 2010, available at <http://www2.ljworld.com/news/2010/nov/27/epa-leader-pledges-fair-decision-power-plant/> (last visited Dec. 30, 2010).

⁵⁰⁵ See Sunflower Integrated Bioenergy, LLC, <http://www.sunflowerbioenergy.com/> (last visited Dec. 3, 2010).

⁵⁰⁶ K.S.A. 55-1637 (West 2010).

⁵⁰⁷ *Id.* at (b), (f), (g).

⁵⁰⁸ See K.A.R. 82-3-311a, 1100, 1101, 1102, 1103, 1104, 1105, 1106, 1107, 1108, 1109, 1110, 1111, 1112, 1113, 1114, 1115, 1116, 1117, 1118, 1119, 1120.

⁵⁰⁹ *Id.* at (c)-(d).

⁵¹⁰ *Id.* at (e).

⁵¹¹ *Id.* at (h)-(i).

⁵¹² K.S.A. 55-1639 through 1640 (West 2010).

⁵¹³ K.S.A. 79-233(a) (West 2010).

- 1) any machinery and equipment used to capture carbon dioxide from industrial and other anthropogenic sources or to convert such carbon dioxide into one or more products;
- 2) any carbon dioxide injection well, as defined in K.S.A. 55-1637, and amendments thereto; and
- 3) any machinery and equipment used to recover carbon dioxide from sequestration.⁵¹⁴

Kansas Statute 79-32,256 provides a deduction of the amortizable costs of CCS equipment over ten years, with CCS equipment defined similarly to the property definitions above.

Kansas has begun experimental CCS projects with funding from the Department of Energy through the Recovery Act. In 2010, the University of Kansas in Lawrence was awarded \$5 million to study CCS and EOR site characterization in south-central Kansas. The University of Utah has also been awarded \$2.6 million to capture, compress and transport one million tons of CO₂ per year for deep saline sequestration research in Coffeyville, Kansas.⁵¹⁵

§ 4(g). Montana's CCS Efforts

Montana has five surface mines and one small underground coal mine.⁵¹⁶ Although Montana has the largest coal reserves in the U.S., the coal is of poorer quality than nearby Wyoming, and no surface mine permits have been issued in Montana since 1988.⁵¹⁷ Four of the surface mines produced 98.3 percent of Montana's coal in 2006.⁵¹⁸ In 2009 Montana produced 39.49 million tons, which was a little less than seven percent of western coal production.⁵¹⁹ About three fourths of the coal mined is shipped to customers in other States and, increasingly, internationally.⁵²⁰ In 2006 Montana was the sixth biggest producer of coal in the United States; however production has expanded only modestly since the mid-1980s and is expected to remain stable.⁵²¹ Expansion is limited due to the low quality of Montana coal, the distance from markets, the need for expensive transportation infrastructure expansion, and political opposition from agricultural interests.⁵²² The state had seven coal-fired generating stations in 2005 with 2,536 MW of capacity, which made up 47.3 percent of the state's electric generating

⁵¹⁴ K.S.A. 79-233(d) (West 2010).

⁵¹⁵ D.O.E., *Kansas Recovery Act Snapshot*, <http://energy.gov/recovery/ks.htm> (last visited Dec. 5, 2010).

⁵¹⁶ EIA Mine Type, *supra*, note 375.

⁵¹⁷ Energy Watch Group, *Coal: Resources and Future Production*, 37 (March 2007), available at <http://www.energywatchgroup.org/Startseite.14+M5d637b1e38d.0.html>.

⁵¹⁸ Source Watch, *Montana and Coal*,

http://www.sourcewatch.org/index.php?title=Montana_and_coal#Active (last visited Dec. 6, 2010).

⁵¹⁹ EIA Mine Type, *supra* note 375.

⁵²⁰ Source Watch, *Montana and Coal*, *supra* note 546.

⁵²¹ *Id.*

⁵²² *Id.*

capacity.⁵²³ However, the vast majority—89.6 percent of Montana's coal-fired electric generating capacity—is found at the four units that comprise the Colstrip Steam Plant (capacity 2,272 MW), and that facility is responsible for more than half the state's CO₂ emissions.⁵²⁴ Because of political opposition, expansion of coal-fired electric generating capacity in Montana will be difficult. However, the state's current governor, Brian Schweitzer, is an ardent advocate for clean coal and CCS and has been called the "Coal Cowboy."⁵²⁵ In 2007, Montana joined the WCI, but it has not passed the legislation needed to participate in the first phase of the Cap and Trade program that will begin in January 2012.⁵²⁶

In Montana regulatory authority for well permits, including injection for EOR or storage, is exercised by the Montana Board of Oil and Gas.⁵²⁷ Montana has a state NEPA-equivalent process administered by the Department of Environmental Quality.⁵²⁸ The environmental requirements place special emphasis on protection of private property rights.⁵²⁹ The state NEPA process is applicable to development on state and private lands. In 2009, Montana passed legislation encouraging and regulating CCS.⁵³⁰

The Act Regulating Carbon Sequestration (Montana CCS Act) maintains the dominance of mineral rights, and allows mineral owners or lessees to drill and/or inject substances through or around sequestration sites as long as the storage site's integrity is preserved. However, unless otherwise established by deed, pore space is presumed to belong to the surface owner.⁵³¹ A sequestration operator must pay the Board of Oil and Gas a fee for each ton of CO₂ injected. If the operator chooses to accept indefinite liability for the site, the fees may be refunded. However, if the Board determines that the operator *must* accept permanent liability, the fees are retained by the Board. The fees will be placed in an account for the Board to use for long-term site monitoring and liability.⁵³²

During the injection phase, operators must post a bond sufficient to cover projected liability. The site operator is liable for the operation and management of the injection well, the storage reservoir, and the actual liquids injected until a

⁵²³ *Id.*

⁵²⁴ *Id.*

⁵²⁵ See Lesley Stahl, *Montana's Coal Cowboy*, 60 MINUTES, (Feb. 26, 2006), available at <http://www.cbsnews.com/stories/2006/02/24/60minutes/main1343604.shtml> (last visited Dec. 6, 2010).

⁵²⁶ See Dustin Till, *Picking Up the Pieces – Western Climate Initiative Releases Cap-and-Trade Program Design*, MARTIN LAW (Aug. 20, 2010), available at <http://www.martenlaw.com/newsletter/20100820-cap-and-trade-design-released> (last visited Dec. 6, 2010).

⁵²⁷ MONT. CODE ANN. § 75-11-101 (West 2010).

⁵²⁸ Montana Environmental Policy Act (MEPA), MONT. CODE ANN. §§ 75-1-101 through 75-1-1112 (West 2010).

⁵²⁹ MONT. CODE ANN. § 75-11-106 (West 2010).

⁵³⁰ An Act Regulating Carbon Sequestration, S.B. 498, 61st Leg., (Mont. 2009) [hereinafter Mont. S.B. 498].

⁵³¹ Mont. S.B. 498 § 1.

⁵³² Mont. S.B. 498 § 2.

Certificate of Completion is issued.⁵³³ The Certificate of Completion may be issued no earlier than fifteen years after injection activities have been completed. The certificate may be issued only if the operator:

- A) is in full compliance with regulations governing the geologic storage reservoir;
- B) can show that the geologic storage reservoir will retain the CO₂ stored in it;
- C) shows that all wells, equipment, and facilities to be used in the postclosure period are in good condition and retain mechanical integrity;
- D) shows that it has plugged wells, removed equipment and facilities, and completed reclamation work as required by the board;
- E) shows that the CO₂ in the geologic storage reservoir has become stable, which means that it is essentially stationary or chemically combined or, if it is migrating or may migrate, that any migration will not cross the geologic storage reservoir boundary; and
- F) shows that the geologic storage operator will continue to provide adequate bond or other surety after receiving the certificate of completion for at least 15 years following issuance of the certificate of completion and that the operator continues to accept liability for the geologic storage reservoir and the stored CO₂.⁵³⁴

Before issuing the Certificate, the Oil and Gas Board must consult with the Department of Environmental Quality; however, the Oil and Gas Board has the final decision of whether to issue the Certificate. If the site complies with the above requirements for fifteen years, the operator may transfer title to the storage reservoir and the CO₂ to the state if the operator can show that the reservoir and wells are in full compliance with the above requirements and that the reservoir will "maintain its structural integrity and will not allow carbon dioxide to move out of one stratum into another or pollute drinking water supplies."⁵³⁵ The Board of Land Commissioners will make the final decision as to whether the state will take ownership of the title.

The Act provides a path for EOR wells to be converted to storage sites.⁵³⁶ It also establishes that contamination of the water in a storage reservoir by CO₂ does not constitute pollution.⁵³⁷ The Act also includes regulations for well-spacing and unitization, discharge, permitting, and other administrative matters.

⁵³³ Mont. S.B. 498 § 3.

⁵³⁴ Mont. S.B. 498 § 4.

⁵³⁵ Mont. S.B. 498 § 4(7)(B)(I & II).

⁵³⁶ Mont. S.B. 498 § 5.

⁵³⁷ Mont. S.B. 498 § 8(25)(c).

In addition to the Montana CCS Act, Montana has passed legislation giving tax breaks for CCS equipment used for capture, transportation, and sequestration; and granting common carrier status for CO₂ pipelines.⁵³⁸ In 2007, Montana passed a statute that prohibits approval of new electrical generation facilities that are primarily fueled by coal unless the facility captures and sequesters at least fifty percent of the CO₂.⁵³⁹ The prohibition is in place “[u]ntil the state or federal government has adopted uniformly applicable statewide standards for the capture and sequestration of carbon dioxide.”⁵⁴⁰

As part of the Department of Energy’s Big Sky Regional Carbon Sequestration Partnership, Montana State University has been studying the viability of a deep saline formation called the Kevin Dome in northern Montana. “Mapping suggests a viable reservoir for CO₂ sequestration at Kevin Dome in the Duperow Formation that has additional capacity not currently occupied by naturally occurring CO₂.”⁵⁴¹

§ 4(h). Nebraska’s CCS Efforts

There are no coal mines in Nebraska, but the state has 15 coal-fired electric power plants with a capacity of 3,204 MW, which is 42.8% of the state’s total capacity.⁵⁴² Three of the power plants, Gerald Gentleman, Nebraska City, and North Omaha, account for 83.0% of the state’s coal-fired power capacity and produce 45.6% of the state’s CO₂.⁵⁴³ Nebraska formed a State Carbon Sequestration Committee in 2000; however, this committee has focused almost exclusively on biological sequestration.⁵⁴⁴ As of this time, Nebraska does not appear to have any legislation centered around geologic CCS.

§ 4(i). Nevada’s CCS Efforts

Nevada has no coal production.⁵⁴⁵ It has two coal-fired power plants. The North Vlamy Station has two units with a total of 522 MWs capacity.⁵⁴⁶ The Reid

⁵³⁸ See MCA §§ 15-6-158; 15-24-3102, 3111; 82-11-180 (West 2010)

⁵³⁹ MONT. CODE ANN. § 69-8-421(8) (West 2010).

⁵⁴⁰ *Id.*

⁵⁴¹ NETL, *Big Sky Regional Carbon Sequestration Partnership—Validation Phase: Fact Sheet*, 5 (July 2010), available at

http://www.netl.doe.gov/technologies/carbon_seq/core_rd/RegionalPartnership/BIGSKY-VP.html (last visited Dec. 6, 2010).

⁵⁴² Source Watch, *Nebraska and Coal*, http://www.sourcewatch.org/index.php?title=Nebraska_and_coal (last visited Dec. 7, 2010).

⁵⁴³ *Id.*

⁵⁴⁴ Neb. Dep’t of Nat’l Res., *Carbon Sequestration, Greenhouse Gas Emissions, and Nebraska Agriculture – Background and Potential: A Report Relating to the Requirements of LB 957 of the 2000 Session of the Nebraska Unicameral and Containing the Recommendations of the Carbon Sequestration Advisory Committee* (Dec. 1, 2001).

⁵⁴⁵ EIA Mine Type, *supra* note 375.

Gardner Station has four units with a total of 612 MWs capacity.⁵⁴⁷ The Mohave Generating Station (1580 MW) ceased operations on Dec. 31, 2005.⁵⁴⁸ There do not appear to be any statutes in Nevada dealing with geologic carbon sequestration. Nevada is only an observer in the Western Climate Initiative, and thus has no plans to participate in the cap-and-trade program. However, Nevada has passed legislation for a renewable portfolio standard for electricity providers, requiring providers to generate, acquire, or save electricity from renewable sources as an increasing percentage of their total output—from six percent in 2005 to at least twenty-five percent in 2025, with at least five percent from solar energy.⁵⁴⁹ Regulations implementing these standards make no mention of CCS or geologic sequestration.⁵⁵⁰

§ 4(j). New Mexico's CCS Efforts

New Mexico has one underground coal mine and five surface mines that produced a total of 25.124 million tons of coal in 2009. This is about four percent of western coal output.⁵⁵¹ New Mexico has eleven coal-fired electric generating units with a total capacity of 4,382 MW.⁵⁵² Ten units at three locations exceed 50 MW.⁵⁵³ The Four Corners Steam generating plant is one of the largest in the country and has been the focus of considerable controversy and legal action over the past few decades. California Edison, a forty-eight percent owner, recently announced that it would sell its shares of the plant to Arizona Public Service. If the purchase is approved, Arizona Public Service plans to shut down units 1, 2, and 3 and install emissions control technology as required by the EPA on units 4 and 5.⁵⁵⁴

On December 1, 2007, the New Mexico Oil Conservation Division published a report pursuant to a 2006 executive order dealing with geologic sequestration.⁵⁵⁵ It

⁵⁴⁶ Source Watch, *Existing Coal Plants in Nevada*, http://www.sourcewatch.org/index.php?title=Category:Existing_coal_plants_in_Nevada (last visited Dec. 7, 2010).

⁵⁴⁷ Nev. Div. Envt'l Protection, *BART Determination Review of NV Energy's Reid Gardner Generating Station Units 1, 2 and 3*, 1 (Oct. 22, 2009).

⁵⁴⁸ Southern Cal. Edison, *Power Generation: Mohave Generation Station*, <http://www.sce.com/powerandenvironment/powergeneration/mohavegenerationstation/> (last visited Dec. 7, 2010).

⁵⁴⁹ NEV. REV. STAT. 704.7821 (West 2010).

⁵⁵⁰ See NEV. ADMIN. CODE 704.8831 - 704.8893 (West 2010).

⁵⁵¹ EIA Mine Type, *supra* note 375.

⁵⁵² Source Watch, *New Mexico and Coal*,

http://www.sourcewatch.org/index.php?title=New_Mexico_and_coal#Existing_coal_plants (last visited Dec. 7, 2010).

⁵⁵³ *Id.* The plants are: Four Corners (2,269 MW), San Juan (1,848 MW), and Escalante (257 MW).

⁵⁵⁴ See Marjorie Childress, *Four Corners Power Plant to Reduce Emissions*, NEW MEXICO INDEPENDENT (Nov. 9, 2010).

⁵⁵⁵ N.M. Energy, Minerals, Nat'l Res. Dep't, Oil Conservation Div., *A Blueprint for the Regulation of Geologic Sequestration of Carbon Dioxide in New Mexico* (Dec. 1, 2007), available at <http://www.emnrd.state.nm.us/ocd/documents/CarbonSequestrationFINALREPORT1212007.pdf> (last

was titled *A Blueprint for the Regulation of Geologic Sequestration of Carbon Dioxide in New Mexico*. The report identified numerous legal issues that needed to be addressed if New Mexico were to embrace carbon sequestration, including the most basic issue that New Mexico has no clear authority to regulate CO₂ injection for sequestration purposes. In the following year, Governor Richardson worked to reduce New Mexico's GHG emissions, but no specific requirements relating to carbon sequestration were imposed.⁵⁵⁶

The legislature did pass SB 994, which recognizes CCS as an "Eligible Generation Plant Cost" and provides tax incentives for CCS.⁵⁵⁷ Tax credits are available to individuals, corporations, and service providers involved with a CCS project that:

captures and sequesters or controls carbon dioxide emissions such that by the later of January 1, 2017, or eighteen months after the commercial operation date, no more than one thousand one hundred pounds per megawatt-hour of carbon dioxide is emitted into the atmosphere.⁵⁵⁸

A public utility that incurs costs in adopting CCS technology may also recover those costs.⁵⁵⁹

On November 2, 2010, regulations for the New Mexico cap-and-trade program under the WCI were finalized.⁵⁶⁰ Although CCS is not an official policy of the New Mexico cap-and-trade program, like the regional programs discussed in Section 2, CCS may be recognized for offset credit if an operation meets certain criteria.⁵⁶¹ New Mexico was the only state besides California that planned to participate in the first phase of the WCI cap-and-trade program that begins in January 2011. However, New Mexico voters elected a republican governor in the November 2010 election who is opposed to cap-and-trade, and who removed all eight members of the Environmental Improvement Board for their "anti-business" stance.⁵⁶² Thus the status of New Mexico's participation is uncertain.

visited Dec. 7, 2010); *see also* N.M. Exec. Order No. 2006-69 (2006), *available at* <http://www.governor.state.nm.us/2006orders.php> (last visited Dec. 7, 2010).

⁵⁵⁶ *See* N.M. Env't Dep't, *Science of Climate Change and New Mexico Projections*, http://www.nmenv.state.nm.us/aqb/GHG/Science_Projections.html (last visited Dec. 7, 2010).

⁵⁵⁷ N.M. STAT. ANN. §§ 7-2-18.25; 7-2A-25; 7-9-114; 7-9G-2; 62-6-288 (West 2010).

⁵⁵⁸ N.M. STAT. ANN. § 7-2-18.25 (L)(2)(C) (West 2010).

⁵⁵⁹ N.M. STAT. ANN. § 62-6-28(B) (West 2010).

⁵⁶⁰ N.M. ADMIN. CODE §§ 20.2.350.1 – 20.2.350.399 (N.M. Reg. Dec. 1 2010), *available at* <http://www.nmepcr.state.nm.us/nmregister/xxi/xxi22/xxi22.pdf> (last visited Dec. 20, 2010).

⁵⁶¹ *See* N.M. ADMIN. CODE § 20.2.350.208(A)(1) (N.M. Reg. Dec. 1, 2010), *available at* <http://www.nmepcr.state.nm.us/nmregister/xxi/xxi22/xxi22.pdf> (last visited Dec. 20, 2010).

⁵⁶² *Governors' Turnover Could Spur Mixed Results For Environmental Policy*, XXI CLEAN AIR REP. (Inside EPA) 23:16 (Nov. 11, 2010); William H. Carlile, *Governor Removes All Eight Members of Board That Approved Carbon Regulation*, 42 Env't Rep. (BNA) 35 (Jan. 7, 2011).

The DOE Southwest Partnership has been experimenting with CCS in the San Juan basin of northwestern New Mexico. A pilot test recently concluded injecting 18,400 tons of CO₂ into a coal bed with high methane production, testing the viability of “enhanced coalbed methane” production. Although this basin is relatively isolated and thus CCS would have to take place locally, there are several power plants with significant CO₂ output in this region, making future CCS efforts there possible.⁵⁶³

§ 4(k). North Dakota’s CCS Efforts

North Dakota produces 2.79% of the nation’s coal from four surface mines.⁵⁶⁴ The state has 15 coal-fired electric power plants with a total capacity of 4,246 MW; seven plants have units larger than 50 MW.⁵⁶⁵ Basin Electric is partnering with Powerspan Corporation and Burns & McDonnell to demonstrate CO₂ removal from the emissions of a lignite-based boiler in Antelope Valley. The U.S. Department of Energy provided \$100 million and the Department of Agriculture announced it was loaning up to \$300 million for the project in January 2009. Basin Electric’s subsidiary also runs the nearby Great Plains Synfuels Plant, which is powered by the Antelope Valley plant and captures about 3 million tons per year of CO₂ and transports it by pipeline to oil fields in Canada for EOR injection and potential permanent storage, making it part of the largest CCS operation in the world.⁵⁶⁶

Perhaps because it is home to successful CCS operations, North Dakota has enacted comprehensive legislation to promote and regulate CCS. In 2009, SB 2095 was passed, setting forth priorities and regulations for geologic storage of CO₂.⁵⁶⁷ The Act declares that North Dakota will promote CCS as in the public interest for both environmental and economic reasons. The Industrial Commission is given authority over all CCS activities, including permitting, enforcement, financial oversight, and field boundaries.⁵⁶⁸ The Commission also has authority to require pore space to be used for storage, even if owners of the pore space have refused their permission.⁵⁶⁹ Stored CO₂ will not be considered a pollutant or a nuisance.⁵⁷⁰ Other property interests will not be harmed by CO₂ storage, and mineral owners may drill through or around the storage space if they comply with Commission

⁵⁶³ New Mexico Bureau of Geology and Mineral Resources, *Carbon Sequestration in the Context of Climate Change*, NEW MEXICO EARTH MATTERS (Summer 2010), available at <http://www.southwestcarbonpartnership.org/> (last visited Dec. 7, 2010).

⁵⁶⁴ EIA Mine Type, *supra* note 375.

⁵⁶⁵ Source Watch, *North Dakota and Coal*,

http://www.sourcewatch.org/index.php?title=North_Dakota_and_coal (last visited Dec. 7, 2010).

⁵⁶⁶ *Id.*; see also Basin Electric Power Coop., *Electricity*,

<http://www.basinelectric.com/Electricity/index.html> (last visited Dec. 7, 2010); Section 1(c), *infra*.

⁵⁶⁷ N.D. SB 2095 (2009); codified at N.D. CENT. CODE §§ 38-20-01 *et seq.* (West 2010).

⁵⁶⁸ N.D. CENT. CODE §§ 38-20-03 (West 2010).

⁵⁶⁹ N.D. CENT. CODE § 38-20-14 (West 2010).

⁵⁷⁰ N.D. CENT. CODE § 38-20-12(1) (West 2010).

guidelines.⁵⁷¹ A trust fund is developed with fees from storage permits. This fund will allow the Commission to assume long-term liability and responsibility for storage reservoirs.⁵⁷² Similar to Montana, North Dakota assigns liability to the operator while injection is underway and until a Certificate of Completion is issued by the Commission.⁵⁷³ The Certificate can be issued ten years after injections have ceased and after the Commission has held public hearings and consulted with the state Department of Health.⁵⁷⁴ Once the Certificate has issued, the CCS operator may transfer liability and ownership of the reservoir to the state of North Dakota.⁵⁷⁵ The legislation also distinguishes CO₂ injection for EOR from geologic storage. EOR injection is regulated under oil and gas regulations unless it is later decided to convert an EOR injection site to a storage site.⁵⁷⁶

North Dakota also provides tax relief for EOR injection projects for the first five years.⁵⁷⁷ CO₂ pipelines can be granted Common Carrier status, which includes eminent domain powers.⁵⁷⁸ Finally, pore space is vested in the surface estate owner and may not be severed from the surface estate. Pore space may, however, be leased without a severance occurring. Mineral ownership remains the dominant interest as under the common law.⁵⁷⁹

North Dakota chose not to join the Midwest Regional Greenhouse Gas Reduction Accord. It did, however, adopt the Midwestern Energy Security and Climate Stewardship Platform, which includes promotion of advanced coal technologies and CCS.⁵⁸⁰

§ 4(I). Oklahoma's CCS Efforts

Oklahoma has one underground coal mine and nine surface coal mines, which are the source of 0.09% of U.S. coal production (down from 0.2% in 2006).⁵⁸¹ The state has 15 coal-fired electric power plants, with 5,720 MW of capacity, which

⁵⁷¹ N.D. CENT. CODE § 38-20-13 (West 2010).

⁵⁷² N.D. CENT. CODE § 38-20-14, 15 (West 2010).

⁵⁷³ N.D. CENT. CODE § 38-20-16 (West 2010).

⁵⁷⁴ N.D. CENT. CODE § 38-20-17 (West 2010).

⁵⁷⁵ *Id.*

⁵⁷⁶ See N.D. CENT. CODE §§ 38-20-19; 38-08-01 *et seq.* (West 2010).

⁵⁷⁷ N.D. CENT. CODE § 7-51.1-03(5) (West 2010).

⁵⁷⁸ N.D. CENT. CODE § 49-19-01 *et seq.* (West 2010).

⁵⁷⁹ N.D. SB 2139 (2009); codified at N.D. CENT. CODE § 47-31-01 through 08 (West 2010).

⁵⁸⁰ See Press Release by Governor Jim Doyle, *Ten Midwestern Leaders Sign Greenhouse Gas Reduction Accord; Also Establish Regional Goals and Initiatives to Achieve Energy Security and Promote Renewable Energy* (Nov. 15, 2007), available at

http://www.wisgov.state.wi.us/journal_media_detail.asp?locid=19&prid=3023 (last visited Dec. 7, 2010).

⁵⁸¹ EIA Mine Type, *supra* note 375.

is 26.6% of the state's total generating capacity.⁵⁸² These plants release 35.0% of the state's CO₂ emissions.⁵⁸³

In 2008, the Oklahoma legislature created the Oklahoma Geologic Storage of Carbon Dioxide task force to prepare recommendations for the legislature on CCS by December 2008.⁵⁸⁴ In 2009, the Oklahoma legislature approved S. 610, which established a new section of law codified at Oklahoma Statutes, Title 27A, § 3-5-101 *et seq.*, known as the Oklahoma Carbon Capture and Geologic Sequestration Act.⁵⁸⁵ The Act gives the Corporation Commission and the Department of Environmental Quality responsibility for implementing the Act with the division of responsibilities determined by the type of reservoir used for sequestration. The Corporation Commission is responsible for oil and gas reservoirs as well as coal-bed methane and mineral brine reservoirs. The Department of Environmental Quality is responsible for all other reservoirs, which would include deep saline formations, unmineable coal seams where methane is not produced, basalt reservoirs, salt domes, and non-mineral bearing shales.⁵⁸⁶ The appropriate state regulatory agency will promulgate rules to administer and enforce the Act. The law provides for the agency to make a determination that a storage facility is suitable and feasible and that it will not contaminate "fresh water or oil, gas, coal, or other commercial mineral deposits" and will not "unduly endanger human health and the environment."⁵⁸⁷ The overseeing agency is also empowered to carry out all duties connected with the EPA's rules for the UIC Program under the SDWA.⁵⁸⁸ The law extends the power of eminent domain to operators of storage facilities.⁵⁸⁹ It creates a Carbon Dioxide Storage Facility Trust Fund to hold the proceeds of fees imposed on each ton of CO₂ injected for storage that will be used to fund the costs of long-term care of the facility.⁵⁹⁰ The long-term monitoring and care of the facility will be the responsibility of the relevant state regulatory authority.⁵⁹¹ The Oklahoma Geologic Storage of Carbon Dioxide task force has been renewed and ordered to continue study of geological storage issues to facilitate CCS development in Oklahoma.⁵⁹²

In 2001, the Oklahoma Conservation Commission was ordered to prepare a report assessing past and future opportunities for carbon sequestration in Oklahoma, both biological and geological.⁵⁹³ As a consequence of this study, the

⁵⁸² Source Watch, *Oklahoma and Coal*, available at http://www.sourcewatch.org/index.php?title=Oklahoma_and_coal (last visited Dec. 8, 2010).

⁵⁸³ *Id.*

⁵⁸⁴ Okla. S.B. 1765 (2008).

⁵⁸⁵ OKLA. STAT. ANN., tit. 27A, §§ 3-5-101 through 106 (West 2010)

⁵⁸⁶ OKLA. STAT. ANN., tit. § 3-5-103 (West 2010).

⁵⁸⁷ OKLA. STAT. ANN., tit. 27A, §§ 3-5-101 through 106 (West 2010).

⁵⁸⁸ OKLA. STAT. ANN., tit. 27A, § 3-5-104 (West 2010).

⁵⁸⁹ *Id.*

⁵⁹⁰ OKLA. STAT. ANN., tit. 27A, § 3-5-106 (West 2010).

⁵⁹¹ *Id.* at §§ 3-5-107 & 108

⁵⁹² Okla. S.B. 1326 (2010).

⁵⁹³ OKLA. STAT. ANN., tit. 27A, § 3-4-103 (West 2010).

Conservation Commission now offers one of the only state-operated certification programs for validating CCS as an offset in connection with EOR operations.⁵⁹⁴ Permanent rules for this program went into effect in 2009.⁵⁹⁵

In 2007, American Electric Power announced a commercial scale CCS project using CO₂ captured from the Northeastern coal-fired plant in Oklahoma. The capture project at Northeastern would be one of the first commercial-scale captures of CO₂ at an existing coal-fired plant and would use a chilled ammonium process.⁵⁹⁶ Commercial operations were projected to begin in 2011, but it now appears the date has been pushed back.⁵⁹⁷

§ 4(m). Oregon's CCS Efforts

Oregon has no coal production.⁵⁹⁸ The state has only two coal-fired power plants. The Portland General Electric Company (PGE) has asked Oregon regulators to approve a plan where it would discontinue the use of coal at its 601 MW Boardman plant, in eastern Oregon, by 2020 in exchange for some leeway on required technology upgrades.⁵⁹⁹ To continue operating until 2020, PGE would spend an estimated \$190 million on nitrogen oxide controls; under the compromise, PGE would still be required to spend \$41 million to control sulfur dioxide and mercury emissions in 2011 and 2012.⁶⁰⁰ Oregon does not appear to have any governmental activity concerning geologic carbon sequestration, although it has passed statutes encouraging biological sequestration.⁶⁰¹

Although Oregon appears to be moving away from coal-based energy generation, recent proposals to expand U.S. coal exports to Asia are based on using northwestern ports in Oregon and Washington as coal-exporting hubs. Environmentalists have vowed to oppose expansion of the ports to export coal.⁶⁰²

⁵⁹⁴ Oklahoma Conservation Commission, *Carbon Sequestration Certification Program*, http://www.ok.gov/conservation/Agency_Divisions/Water_Quality_Division/WQ_Carbon_Sequestration/Geologic_Sequestration/ (last visited Dec. 8, 2010); *see also* OKLA. STAT. ANN., tit. 27A, § 3-4-103(B) (West 2010).

⁵⁹⁵ *See* OKLA. ADMIN. CODE § 155:30-1-1 through 30-13-2 (2009).

⁵⁹⁶ *See* American Electric Power, *Press Release* (Oct. 16, 2007), *available at* <http://www.aep.com/newsroom/newsreleases/?id=1412> (last visited Dec. 8, 2010).

⁵⁹⁷ PowerGen, *Carbon Capture R&D Gets \$8 Billion Boost* (April 1, 2009), *available at* <http://www.powergenworldwide.com/index/display/articledisplay/358958/articles/power-engineering/volume-113/issue-4/departments/startup/carbon-capture-rampd-gets-8-billion-boost.html> (last visited Dec. 8, 2010).

⁵⁹⁸ EIA Mine Type, *supra* note 375.

⁵⁹⁹ Tom Alkire, *Northwest's Only Coal-Fired Power Plants May Halt Use of Coal by 2025*, *Switch Fuels*, 41 Env't Rep. (BNA) 992 (May 7, 2010).

⁶⁰⁰ *Id.*

⁶⁰¹ *See, e.g.*, OREG. REV. STAT. ANN. §§ 468A.250.1(h) & (i); 468A.290.2(a); 568.550.r(H).

⁶⁰² *See, e.g.*, Scott Learn, *Mining Companies Aim to Export Coal to China through Northwest Ports*, THE OREGONIAN (Sept. 8, 2010), *available at*

§ 4(n). South Dakota's CCS Efforts

South Dakota has no coal production.⁶⁰³ It has two coal-fired electric generating plants with 481 MW of capacity. One facility, the "Big Stone" plant, is responsible for 30.7% of the state's CO₂ emissions.⁶⁰⁴ South Dakota has enacted legislation defining CO₂ as one of the fluids that subjects a pipeline to regulation as a transmission facility by the South Dakota Public Utilities Commission.⁶⁰⁵ The CO₂ must be at least ninety percent CO₂ molecules compressed into a super critical state.⁶⁰⁶ A pipeline must obtain a permit from the Public Utilities Commission, and needs legislative approval for a trans-state line.⁶⁰⁷ Approval from the legislature includes the power of eminent domain.⁶⁰⁸ Other than this legislation, South Dakota does not appear to have legislation dealing with CCS or the related issues of pore space ownership, liability, etc.⁶⁰⁹ South Dakota has observer status in the Midwestern Greenhouse Gas Reduction Accord.

§ 4(o). Texas's CCS Efforts

Texas has twelve surface mines that produce 3.26% of U.S. coal.⁶¹⁰ Texas is the third ranked state for electricity produced from coal, which helps make the state the nation's highest emitter of CO₂. Coal is used to produce 36.5% of the electricity generated in Texas.⁶¹¹ There are 40 coal-fired generators at 20 locations in Texas. They have a combined capacity of 21,240 MW; 39 of the units exceed 50 MW.⁶¹²

Texas is a state where environmental groups have actively worked to prevent expansion of coal-fired electric power facilities.⁶¹³ Luminant (formerly TXU), for example, in 2007 agreed to cancel 8 of its 11 planned coal-fired power

http://www.oregonlive.com/environment/index.ssf/2010/09/global_mining_companies_are_fo.html (last visited Dec. 8, 2010).

⁶⁰³ EIA Mine Type, *supra* note 375.

⁶⁰⁴ Source Watch, *South Dakota and Coal*, available at

http://www.sourcewatch.org/index.php?title=South_Dakota_and_coal (last visited Dec. 8, 2010).

⁶⁰⁵ S.D. CODIFIED LAWS §§ 49-41B-2 and 49-41B-2.1(2) (West 2010).

⁶⁰⁶ S.D. CODIFIED LAWS § 49-41B-2(3) (West 2010)

⁶⁰⁷ S.D. CODIFIED LAWS §§ 49-41B-4; 49-41B-4.1 & 2 (West 2010).

⁶⁰⁸ S.D. CODIFIED LAWS § 21-35-1.1 (West 2010).

⁶⁰⁹ *But see* Blayne N. Grave, Student Article, *Carbon Capture and Storage in South Dakota: The Need for a Clear Designation of Pore Space Ownership*, 55 S.D. L. REV. 72 (2010) (calling for legislation to regulate pore space ownership).

⁶¹⁰ EIA Mine Type, *supra* note 375.

⁶¹¹ Source Watch, *Texas and Coal*, http://www.sourcewatch.org/index.php?title=Texas_and_coal (last visited Dec. 9, 2010).

⁶¹² *Id.*

⁶¹³ *See The Debate Over Coal Plants in Texas*, THE DALLAS MORNING NEWS, April 2, 2007, available at <http://www.dallasnews.com/sharedcontent/dws/news/longterm/stories/buscoalresources.162b5ce1.html> (last visited Dec. 9, 2010).

plants in return for environmental organizations agreeing not to oppose three new coal-fired power plants.⁶¹⁴ The company also agreed to expand wind generation and invest \$400 million in energy efficiency measures.⁶¹⁵ In another challenge, environmentalists agreed to drop challenges to a new 303 MW facility in return for numerous concessions by NuCoastal Power, including an agreement to invest in CCS if the technology becomes available.⁶¹⁶

The Summit Power Group is developing a CCS facility called the Texas Clean Energy Project (TCEP). It will use CCS pre-combustion technology to capture 90% of the CO₂ emissions from a 400 MW IGCC coal-fired plant in west Texas. It will use the same CCS technology as planned for the FutureGen project in Mattoon, Illinois. The captured CO₂ will be injected into an oil field.⁶¹⁷ On December 4, 2009, DOE awarded TCEP \$350 million to help develop the facility. It will begin construction in the fall of 2011 and begin sequestering carbon in 2014.⁶¹⁸ DOE has also awarded \$154 million to NRG Energy, Inc. of New Jersey to build a 60 MW post-combustion CCS project in Thompsons, Texas. The project is meant to demonstrate the possibility of CCS for existing coal-powered units. The CO₂ will be used for EOR in nearby oil fields.⁶¹⁹

Texas promotes a diverse energy portfolio and claims to have the most experience implementing and regulating EOR. In recent years, the legislature has enacted legislation regulating and encouraging CCS while the Texas governor publicly denounces federal regulation of the energy sector and state regulators have battled EPA regulation of CO₂ injection for EOR.⁶²⁰ A full coverage of the Texas legislation is beyond the scope of this paper. Instead, highlights from some of the major bills are summarized.

§ 4(o)(1). Texas SB 1387

Texas SB 1387 became law in September of 2009. SB 1387 defines anthropogenic CO₂ and assigns the Texas Railroad Commission as the regulatory

⁶¹⁴ See *How Environmentalists Shaped TXU Deal*, NPR, Feb. 27, 2007, available at <http://www.npr.org/templates/story/story.php?storyId=7615616> (last visited Dec. 9, 2010).

⁶¹⁵ *Kansas Pact May Set New Floor For Resolving Coal Plant Disputes*, XVIII Clean Air Rep. (Inside EPA) 7 (Apr. 7, 2007).

⁶¹⁶ Source Watch, *Texas and Coal*, *supra* note 639.

⁶¹⁷ *Id.*

⁶¹⁸ Texas Clean Energy Project, *The Texas Clean Energy Project: A “NowGen” Carbon Capture Facility*, <http://texascleanenergyproject.com/> (last visited Dec. 9, 2010); DOE, *Recovery Act: Clean Coal Power Initiative Round III*, available at <http://fossil.energy.gov/recovery/projects/cepi.html> (last visited Dec. 9, 2010) [hereinafter DOE, *Recovery Act*].

⁶¹⁹ DOE Recovery Act, *supra* note 646.

⁶²⁰ See, e.g., Ramit Plushnick-Masti, *Driller Denies That It Contaminated Texas Aquifer*, CHRON, Dec. 8, 2010, available at <http://www.chron.com/disp/story.mpl/ap/tx/7328990.html> (last visited Dec. 9, 2010); Governor Rick Perry Press Release, *Gov. Perry: The Biggest Challenge to the Energy Industry is Federal Overregulation*, (July 28, 2010), available at <http://governor.state.tx.us/news/press-release/14940/> (last visited Dec. 9, 2010).

agency for CO₂ storage or injection. Anthropogenic CO₂ includes any incidental substances that might be added to the CO₂ during extraction or injection processes.⁶²¹ Injection of CO₂ for storage purposes is also distinguished from injection for EOR.⁶²²

The Railroad Commission will issue permits for CO₂ storage sites and may impose fees that will be placed in an Anthropogenic CO₂ Trust fund, which can be used to cover permitting, monitoring, inspecting, and enforcing costs.⁶²³ The executive director of the storage operation must provide a letter assuring that the operation "will not injure any freshwater strata in that area and that the formation or stratum to be used for the geologic storage facility is not freshwater sand."⁶²⁴ The Railroad Commission must also assure that specific safety and financial conditions are met before issuing a CO₂ storage permit, including that the well may not impair existing rights, including mineral rights.⁶²⁵

The Texas legislation differs from some other states by making the use of CO₂ for storage or for EOR equivalent. "A conversion of an anthropogenic carbon dioxide injection well from use for enhanced recovery operations to use for geologic storage is not considered to be a change in the purpose of the well."⁶²⁶ Although a potential storage site that has received CO₂ injection for EOR must be converted to an official and permitted storage site in order to qualify for title transfer to the state, this section blurs the line between injecting CO₂ for EOR, which has been regulated by the Railroad Commission and does not require a specific permit, and injecting CO₂ for permanent storage, which subjects the operations to the requirements described in this legislation. The rules outlining CO₂ ownership also specifically exempt CO₂ used in EOR.⁶²⁷ Stored CO₂ is the property of the storage operator or the storage operator's heirs, successors, or assigns.

SB 1386 creates a trust fund for CCS, and it also provides for extraction of stored CO₂ for commercial or industrial uses.⁶²⁸ The legislation also requires a report on site identification and state land leasing issues from the Commissioner of the General Land Office in coordination with the Bureau of Economic Geology of The University of Texas at Austin, the Railroad Commission of Texas, the Texas Commission on Environmental Quality, the heads of other appropriate agencies by December 1, 2010.⁶²⁹ A separate report is also required from the Texas Commission on Environmental Quality and the Railroad Commission of Texas, in consultation with the Bureau of Economic Geology of The University of Texas at Austin. This

⁶²¹ TEX. WATER CODE ANN. § 27.002(19) (Vernon 2009).

⁶²² TEX. WATER CODE ANN. § 27.042 (Vernon 2009).

⁶²³ TEX. WATER CODE ANN. § 27.043 through 045 (Vernon 2009).

⁶²⁴ TEX. WATER CODE ANN. § 27.046 (Vernon 2009).

⁶²⁵ TEX. WATER CODE ANN. § 27.051(a) (Vernon 2009).

⁶²⁶ TEX. NAT. RES. CODE ANN. § 91.802(c) (Vernon 2009).

⁶²⁷ TEX. NAT. RES. CODE ANN. § 120.002(a) (Vernon 2009).

⁶²⁸ TEX. NAT. RES. CODE ANN. §§ 120.003 & .004 (Vernon 2009).

⁶²⁹ Tex. SB 1387, § 9 (2009).

report is also due December 1, 2010 and should cover issues related to both EOR and non-EOR injection of CO₂ as well as agency jurisdictional issues, including federal jurisdiction, for CO₂ injection.⁶³⁰ On December 2, 2010, the Texas Railroad Commission (the agency responsible for regulating resource extraction in Texas) approved new rules regulating CCS, as required by section 11 of SB 1387.⁶³¹

§ 4(o)(2). Texas HB 1796: Offshore Geologic Storage of CO₂.

Texas HB 1796, effective September 1, 2009, empowers the Texas Natural Resource Conservation Commission (TNRC) to establish an offshore CO₂ repository to be located on offshore state lands.⁶³² The repository will be managed by the School Land Board, which may charge fees and establish carbon credits. The School Land Board will also acquire title to any CO₂ stored in the repository.⁶³³ When the Board acquires title, it shall also assume liability; however, the producer of the CO₂ remains liable for any act or omission regarding the CO₂ before it was stored.⁶³⁴

HB 1796 also establishes Advanced Clean Energy Projects, which include coal-powered electrical generating plants that capture and store at least fifty percent of emissions. Such generation plant could qualify for the Advanced Clean Energy Project grant and loan program.⁶³⁵ Section 30 of HB 1796 emphasizes Texas' commitment to developing CCS:

The purpose of the changes in law made by this Act is to encourage the development of onshore and offshore geologic storage of carbon dioxide including by encouraging the development of advanced clean energy projects that capture carbon dioxide and sequester not less than 50 percent of the captured carbon dioxide in onshore or offshore geologic repositories. Securing the necessary capacity for geologic sequestration is essential to the success of carbon capture strategies, such as the advanced clean energy projects facilitated by the changes in law made by this Act. The success of the offshore repositories facilitated by this Act depends on an adequate supply of anthropogenic carbon dioxide, which is not currently being captured at industrial facilities in this state. The advanced clean energy grants established in this Act are intended to create the supply of

⁶³⁰ Tex. SB 1387, § 10 (2009).

⁶³¹ See 35 TEX. REG. 9177 (Oct. 15, 2010); 16 TEX. ADMIN. CODE §§ 5.101, 5.102, 5.201, 5.202, 5.203, 5.204, 5.205, 5.206, 5.207, 5.208 (Vernon 2010).

⁶³² TEX. HEALTH & SAFETY CODE ANN. § 382.503 (Vernon 2009).

⁶³³ TEX. HEALTH & SAFETY CODE ANN. §§ 382.505 & 507 (Vernon 2009).

⁶³⁴ TEX. HEALTH & SAFETY CODE ANN. § 382.508 (Vernon 2009).

⁶³⁵ TEX. GOV'T CODE ANN. § 447.013 (Vernon 2009); TEX. HEALTH & SAFETY CODE ANN. § 391.002 (Vernon 2009).

anthropogenic carbon dioxide necessary to the success of the offshore repositories facilitated by this Act.⁶³⁶

§ 4(o)(3). Texas HB 469:

House Bill 469 offers tax incentives for CCS activities. A franchise tax credit of \$100 million or 10 percent of the total cost of a project is available to entities that qualify as Clean Energy Projects. To qualify for the credit, a CCS project would have to involve construction of a new facility and sequester at least 70 percent of emissions from electricity generation. The credit is only available in 2013.⁶³⁷ The Clean Energy Project definition is modified with the following additional text:

. . . whether the project is implemented in connection with the construction of a new facility or in connection with the modification of an existing facility and whether the project involves the entire emissions stream from the facility or only a portion of the emissions stream from the facility.⁶³⁸

A Clean Energy Project is further modified to require a pre-combustion facility to capture at least 70 percent of emitted CO₂. It also requires that captured CO₂ is capable of being both permanently sequestered for 1,000 years with 99 percent retention and supplied for EOR purposes.⁶³⁹ The Railroad Commission is given authority to certify Clean Energy Projects, but only three projects may be certified. A Clean Energy Project applicant must contract with the Bureau of Economic Geology of The University of Texas at Austin for monitoring, measuring, and verification of the project.⁶⁴⁰

Section 4 of the legislation provides a sales tax exemption for personal property used in connection with a Clean Energy Project to capture, transport, inject or prepare CO₂ for injection within the state.⁶⁴¹ A fifty percent reduction in the recovered oil tax rate is also provided for EOR operations that use CO₂ captured in Texas.⁶⁴²

In 2009, Senate Bill 126 and its companion House Bill 4384 would have placed a two-year moratorium on coal-fired power plants that are proposed without

⁶³⁶ Texas HB 1796, § 30 (Sep. 1, 2009).

⁶³⁷ TEX. GOV'T CODE ANN. § 490.352 (Vernon 2009).

⁶³⁸ TEX. HEALTH & SAFETY CODE ANN. § 382.003(1-a)(A) (Vernon 2009).

⁶³⁹ TEX. NAT. RES. CODE ANN. § 120.001(2)(C), (D), & (E); .001(4) (Vernon 2009).

⁶⁴⁰ TEX. NAT. RES. CODE ANN. §§ 120.001 through 120.004 (Vernon 2009).

⁶⁴¹ TEX. TAX CODE ANN. § 151.334 (Vernon 2009).

⁶⁴² TEX. TAX CODE ANN. § 202.0545(a) and (d) (Vernon 2009).

CCS capabilities. The bills were referred to committee but did not pass during the 2009 session.⁶⁴³

Texas has developed significant legislation on CCS over the past several years, and although it is not a state that has promoted either federal or regional regulation of GHGs or action to prevent climate change, it has declared itself a leader in carbon regulation and storage because of its decades of experience with EOR and global leadership in energy development.⁶⁴⁴ At least one private industry group is monitoring and promoting Texas' efforts to support market-based CCS.⁶⁴⁵ Texas is the last state that claims it is not ready or willing to implement EPA GHG permitting requirements.⁶⁴⁶ Texas has indicated that it cannot or will not impose GHG permits in 2011 as required because they are prohibited by law from doing so.⁶⁴⁷

§ 4(p). Utah's CCS Efforts

Utah's is the nation's 13th largest coal producer, slipping a notch from 2006.⁶⁴⁸ The state has eight underground coal mines.⁶⁴⁹ There are six coal-burning electric utility plants in the state with eleven generating units, producing over 9,350 MW.⁶⁵⁰

§ 4(p)(1). Utah's Procurement Act Carbon Sequestration Framework (SB 202).

Section 701 of the Utah Energy Resources Procurement Act (Procurement Act), provides a framework for carbon sequestration in the state.⁶⁵¹ Section 701 provides, "by January 1, 2011, the Division of Water Quality and the Division of Air Quality, on behalf of the Board of Water Quality and the Board of Air Quality,

⁶⁴³ See HB 4384 and SB 126 legislative history, available at <http://www.capitol.state.tx.us/BillLookup/BillNumber.aspx> (last visited Dec. 10, 2010).

⁶⁴⁴ See Governor Rick Perry Press Release, *Gov. Perry Speaks at Clean Carbon Policy Summit* (Oct. 5, 2010), available at <http://www.governor.state.tx.us/news/press-release/15240/> (last visited Dec. 10, 2010).

⁶⁴⁵ See Texas Carbon Capture and Storage Association, <http://txccsa.org/> (last visited Dec. 10, 2010);

⁶⁴⁶ Steven D. Cook, *All States but Texas Ready to Implement Greenhouse Gas Permitting Requirements*, 41 Env't Rep. (BNA) 2450 (Nov. 5, 2010).

⁶⁴⁷ See *Wyoming Becomes Latest State to Rebuff EPA on Climate Regulations*, XXI CLEAN AIR REP. (Inside EPA) 21:11 (Oct. 14, 2010); *EPA Eyes Texas Permit Audit Revision Amid State Fear of Facility Closures*, XXI CLEAN AIR REP. (Inside EPA) 21:17 (Aug. 19, 2010).

⁶⁴⁸ Source Watch, *Utah and Coal*, http://www.sourcewatch.org/index.php?title=Utah_and_coal (last visited Dec. 10, 2010); EIA Mine Type, *supra* note 375.

⁶⁴⁹ EIA Mine Type, *supra* note 375.

⁶⁵⁰ Utah Geological Survey, *Electricity*, <http://geology.utah.gov/emp/energydata/electricitydata.htm> (last visited Dec. 10, 2010). The plants are Bonanza (499.5 MW), Intermountain 1 (820 MW) & 2 (820 MW), Carbon 1 (75 MW) & 2 (113.6 MW), Hunter 1 (488.3 MW) & 2 (488.3 MW) & 3 (495.6 MW), Huntington 1 (498 MW) & 2 (498 MW) and Sunnyside Cogeneration (58.1 MW). Kennecott Utah Copper Company has a non-utility plant with four units rated at a total of 182 MW.

⁶⁵¹ UTAH CODE ANN. § 54-17 101 et seq. (2005).

respectively, in collaboration with the commission and the Division of Oil, Gas, and Mining and the Utah Geological Survey, shall present recommended rules to the Legislature's Administrative Rules Review Committee for the following in connection with carbon capture and accompanying geological sequestration of captured carbon.”⁶⁵² These rules are to: 1) ensure adequate health and safety standards are met; 2) minimize risk of unacceptable leakage from the injection well and injection zone; and 3) provide adequate regulatory oversight and public information concerning carbon capture and geologic sequestration.⁶⁵³

The statute enumerates aspects of carbon sequestration that are to be included in the administrative rules: site characterization approval; geomechanical, geochemical, and hydrogeological simulation; risk assessment; mitigation and remediation protocols; issuance of permits for test, injection, and monitoring wells; specifications for the drilling, construction, and maintenance of wells; issues concerning ownership of subsurface rights and pore space; allowed composition of injected matter; testing, monitoring, measurement, and verification for the entirety of the carbon capture and geologic sequestration chain of operations, from the point of capture of the carbon dioxide to the sequestration site; closure and decommissioning procedure; short- and long-term liability and indemnification for sequestration sites; conversion of enhanced oil recovery operations to carbon dioxide geological sequestration sites; and other issues as identified.⁶⁵⁴

Once the listed Departments and Divisions have drafted rules to effectuate the mandates of section 701, the entities shall report any needed statutory changes to the Legislature's Administrative Rules Review Committee.⁶⁵⁵ The statute requires these entities to submit a progress report on rule development to the Public Utilities and Technology and Natural Resources, Agriculture, and Environment Interim Committees by July 1, 2009.⁶⁵⁶

Like other states, Utah distinguishes carbon storage from other uses, such as EOR. The carbon sequestration rules only apply to “the injection of carbon dioxide and other associated injectants in approved types of geological formations for the purpose of reducing emissions to the atmosphere through long-term geological sequestration as required by law or undertaken voluntarily or for subsequent beneficial reuse.”⁶⁵⁷ Carbon sequestration rules do not apply to the injection of fluids for Class II injection wells as defined in 40 C.F.R. 144.6(b) for the purpose of EOR.⁶⁵⁸

⁶⁵² UTAH CODE ANN. § 54-17-701(1) (2009).

⁶⁵³ UTAH CODE ANN. § 54-17-701(6) (2009).

⁶⁵⁴ UTAH CODE ANN. § 54-17-701(1)(a)-(m)(2009).

⁶⁵⁵ UTAH CODE ANN. § 54-17-701(2) (2009).

⁶⁵⁶ UTAH CODE ANN. § 54-17-701(3) (2009). As of December 10, 2010 the State of Utah's climate change website has not yet posted or provided information on this progress report.

⁶⁵⁷ UTAH CODE ANN. § 54-17-701(4) (2009).

⁶⁵⁸ UTAH CODE ANN. § 54-17-701(5) (2009).

In addition to establishing an administrative rule framework, the Procurement Act includes carbon sequestration in its general energy procurement provisions. For example, subsection 602 *et seq.* seek to have 20 percent of Utah's adjusted electric utility sales come from "qualifying electric" or "renewable sources" by 2025.⁶⁵⁹ This percentage is "computed based upon *adjusted* retail electric sales, which is the total annual number of kilowatt-hours of retail electric sales by an electrical corporation, reduced by "the amount of . . . kilowatt-hours attributable to electricity generated or purchased in that calendar year from qualifying . . . carbon sequestration generation."⁶⁶⁰ In calculating the required percentage of non-carbon electric sales, a Utah electric entity may include the number of tons of sequestered carbon either sequestered or purchased by the entity.

Under the Procurement Act qualifying carbon sequestration must come from a fossil-fueled facility within the Western Electricity Coordinating Council⁶⁶¹ that becomes operational or retrofitted after January 1, 2008 and "reduces carbon dioxide emissions into the atmosphere through permanent geological sequestration or through another verifiably permanent reduction in carbon dioxide emissions through the use of technology."⁶⁶² Kilowatt-hours eligible to be included in the adjusted electric retail sales equation are "kilowatt-hours supplied by a facility during the calendar year multiplied by the ratio of the amount of carbon dioxide captured from the facility and sequestered to the sum of the amount of carbon dioxide captured from the facility and sequestered plus the amount of carbon dioxide emitted from the facility during the same calendar year."⁶⁶³

Utah also enacted the Utah Municipal Utility Carbon Emission Reduction Act (Municipal Act), which is similar to the Procurement Act but focuses on municipal reductions in CO₂ emissions instead of reductions from electrical corporations. The Municipal Act mirrors the Procurement Act in its central provisions and inclusions of carbon sequestration.⁶⁶⁴

⁶⁵⁹ UTAH CODE ANN. § 54-17-602(1)(a) (West 2010).

⁶⁶⁰ UTAH CODE ANN. § 54-17-601(1)(a) (2008).

⁶⁶¹ The Western Electricity Coordinating Council (WECC) is the regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection. In addition, WECC assures open and non-discriminatory transmission access among members, provides a forum for resolving transmission access disputes, and provides an environment for coordinating the operating and planning activities of its members as set forth in the WECC Bylaws.

WECC is geographically the largest and most diverse of the eight Regional Entities that have Delegation Agreements with the North American Electric Reliability Corporation (NERC). WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between. Due to the vastness and diverse characteristics of the region, WECC and its members face unique challenges in coordinating the day-to-day interconnected system operation and the long-range planning needed to provide reliable electric service across nearly 1.8 million square miles. Western Electricity Coordinating Council, *About WECC* <http://www.wecc.biz/About/Pages/default.aspx> (last visited Dec. 10, 2010).

⁶⁶² UTAH CODE ANN. § 54-17-601(6) (West 2010).

⁶⁶³ UTAH CODE ANN. § 54-17-601(2) (West 2010).

⁶⁶⁴ See UTAH CODE ANN. § 10-19-201(West 2010) (setting a 20 percent goal for qualifying or renewable energy in municipal utility retail electric sales); UTAH CODE ANN. § 10-19-102(1)(a) (West

§ 4(p)(2). The Utah Carbon Capture and Geologic Sequestration Working Group.

In addition to passing laws regarding carbon sequestration, Utah has also created a Carbon Capture and Geologic Sequestration Working Group (CCGS Workgroup) under the Utah Department of Environmental Quality.⁶⁶⁵

The CCGS Workgroup has two primary goals. First, the group is to aid the appropriate state departments and divisions with implementing the Procurement and Municipality Acts by helping draft relevant administrative rules. Additionally, the CCGS Workgroup must assure these rules comply with existing state statutes and administrative rules as well as existing and proposed federal statutes and regulations.⁶⁶⁶ When asked about the progress of CCGS Workgroup's mandate to create a progress report on the draft administrative rules by July, 2009, the Department of Environmental Quality provided a May 20, 2009 "Progress Report"⁶⁶⁷ as a power-point presentation given to the Utah legislature.⁶⁶⁸ However, this Progress Report does not contain any substantive information regarding rules not included in the Procurement Act. The report makes the legislature aware of the CCGS Workgroup website and synthesizes some of the general carbon sequestration information available on the website.⁶⁶⁹

The second task of the CCGS Workgroup is to prepare comments for the federal "Proposed Rule for Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO₂) Geologic Sequestration (GS) Wells."⁶⁷⁰ The period for general comment closed on December 24, 2008, and in August 2009 the EPA released its Notice of Data Available for the rule and requested more public comment.⁶⁷¹ In December 2010, the EPA published the final UIC rule in the Federal Register.⁶⁷² The CCGS Workgroup website provides substantial background information and documents

2010)(including carbon sequestration in the adjusted retail sales rate); UTAH CODE ANN. § 10-19-102(2) (defining how to calculate deductible kilowatt-hours from carbon sequestration); UTAH CODE ANN. § 10-19-102(7) (defining qualifying carbon sequestration facilities).

⁶⁶⁵ See generally, State of Utah, Climate Change, Carbon Capture and Geologic Sequestration Workgroup, http://www.climatechange.utah.gov/CCGS_WG.htm (last visited Dec. 10, 2010) [hereinafter CCGSW].

⁶⁶⁶ *Id.*

⁶⁶⁷ UTAH DEPT. OF ENVTL. QUALITY, CARBON CAPTURE AND GEOLOGIC SEQUESTRATION ADMINISTRATIVE RULE DEVELOPMENT: PROGRESS REPORT, presented to the Natural Resources, Agriculture, And Environment Interim Committee, (May 20, 2009) (on file with the author) [hereinafter "PROGRESS REPORT"].

⁶⁶⁸ E-mail from Rusty Lundberg, Manager, Energy and Sustainability Group, Utah Department of Environmental Quality (October 2, 2009, 02:54 MST) (on file with author).

⁶⁶⁹ See UTAH DEQ, PROGRESS REPORT, *supra* note 695.

⁶⁷⁰ See CCGSW, *supra* note 693.

⁶⁷¹ Environmental Protection Agency, Underground Injection Control Program, http://www.epa.gov/ogwdw000/uic/wells_sequestration.html (last visited Dec. 30, 2010)

⁶⁷² Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO₂), 75 FR 77230 (Dec. 10, 2010) (to be codified at 40 CFR 124).

relating to climate change and carbon sequestration.⁶⁷³

The CCGS Workgroup “consists of an over-arching Steering Committee; three Subcommittees (CO₂ Capture and Separation, CO₂ Compression and Transport, and CO₂ Injection Well) that will focus on developing rules for the three major aspects of CCGS; an Advisory Committee that provides technical support to the Steering Committee and the Subcommittees; and a Stakeholder Group that provides for public and stakeholder input during the rules development process.”⁶⁷⁴

§ 4(p)(3). Other Carbon Sequestration Activities in Utah

Utah has joined the U.S. DOE’s Southwest Partnership on Carbon Sequestration (SWP)⁶⁷⁵ to conduct research on CCS.⁶⁷⁶ The SWP has begun work on the Farnham Dome Project near Price, Utah to experiment with deep saline CO₂ injection.⁶⁷⁷ The project is designed to:

validate the information and technology developed under the Characterization and Validation Phases relative to research and field activities, public outreach efforts, and regional characterization. Specific objectives include:

- Develop an overall methodology that optimizes engineering and planning for future commercial-scale sequestration projects.
- Conduct successful large-scale CO₂ injection projects targeting deep saline formations present throughout the western U.S.
- Achieve a more thorough understanding of the science, technology, regulatory framework, risk factors, and public opinion issues associated with large-scale injection operations.
- Validate MMV activities; modeling, and equipment operations.
- Refine capacity estimates of the target formation in the region, using results of the test.⁶⁷⁸

In general, the test project will follow an injection schedule for 4 years, 2008-2011, eventually injecting 900,000 metric tons (1 million U.S. tons) of CO₂ per

⁶⁷³ See CCGSW, *supra* note 693.

⁶⁷⁴ *Id.*

⁶⁷⁵ See generally, Southwest Partnership on Carbon Sequestration, <http://www.southwestcarbonpartnership.org> (last visited Dec. 10, 2010).

⁶⁷⁶ State of Utah, Climate Change, Carbon Capture and Geologic Sequestration in Utah, http://www.climatechange.utah.gov/CCGS_in_Utah.htm (last visited Dec. 10, 2010).

⁶⁷⁷ *Id.*

⁶⁷⁸ Southwest Partnership on Carbon Sequestration, Deep Saline Deployment Project: Farnham Dome Deep Saline CO₂ Sequestration Project: Fact Sheet, 3, available at http://www.netl.doe.gov/publications/proceedings/08/rsp/factsheets/24-SWP_Deep%20Saline%20Sequestration_PhIII.pdf (last visited Dec. 10, 2010) [hereinafter “Farnham Dome Fact Sheet”].

year.⁶⁷⁹ The project targets deep Jurassic-, Triassic-, and Permian-aged sandstones formations for injection because these “formations are also targets of potential commercial sequestration throughout the western United States.”⁶⁸⁰ The project will include a “dual completion” consisting of injection in two different formations at the same time within the same stratigraphy so “portability of science and engineering results can begin to be evaluated.”⁶⁸¹

The Farnham Dome site will be extensively monitored to understand CO₂ movement and stability.⁶⁸² CO₂ for the project includes natural CO₂ and, potentially, CO₂ from a coalbed methane (CBM) production field northwest of Price, Utah; the CBM operation currently emits more than 100,000 tons of CO₂ per year. A short pipeline would need to be added to facilitate injection of the captured CO₂ into the deep saline reservoirs.⁶⁸³

The DOE also contributed funding to a three-year project that studied the geologic storage potential of saline aquifers beneath the Colorado Plateau in Utah, including the Paradox Basin in southeastern Utah.⁶⁸⁴

§ 4(q). Washington’s CCS Efforts

There is almost no coal produced in Washington.⁶⁸⁵ Washington has one coal-fired power plant. The Centralia plant, owned by TransAlta Centralia Generation LLC, is a 1,376 MW plant located near Olympia. It is the largest source of GHG emissions in the state. On April 26, 2010, the company agreed to reduce its GHG emissions and is expected to eliminate coal as a fuel for the power plant by 2025.⁶⁸⁶ It has a nameplate capacity of 1,460 MW and was placed in-service in 1972 and 1973. It has 5.2 percent of the state’s generating capacity.⁶⁸⁷

Washington has set an GHG emissions reduction target to return to 1990 levels by 2020, 25 percent below 1990 levels by 2035, and 50 percent below by

⁶⁷⁹ *Id.*

⁶⁸⁰ *Id.* at 2.

⁶⁸¹ *Id.*

⁶⁸² *Id.* at 3-4.

⁶⁸³ *Id.* at 3.

⁶⁸⁴ See Utah Geological Survey, CO₂ Sequestration Project Overview: Reactive, Multi-phase Behavior of CO₂ in Saline Aquifers beneath the Colorado Plateau, *available at* <http://geology.utah.gov/emp/co2sequest/overview.htm> (last visited Dec. 10, 2010).

⁶⁸⁵ EIA Mine Type, *supra* note 375 shows no coal produced. But Source Watch says 2.6 million tons was produced in 2006, which is 0.2 % of the U.S. production. Source Watch, *Washington (State) and Coal*, [http://www.sourcewatch.org/index.php?title=Washington_\(State\)_and_coal](http://www.sourcewatch.org/index.php?title=Washington_(State)_and_coal) (last visited Dec. 10, 2010).

EPA supports the lack of coal production in Washington state since 2000. EPA, *The Pacific and Central Coal Regions*, Attachment 11, EPA 816-R-04-003, at A11-1 (June 2004), *available at* http://www.epa.gov/ogwdw/uic/pdfs/cbmstudy_attach_uic_attach11_washington.pdf (last visited Dec. 10, 2010).

⁶⁸⁶ Source Watch, *Washington and Coal*, *supra* note 713.

⁶⁸⁷ *Id.*

2050.⁶⁸⁸ In 2007, the state of Washington passed the Climate Change Mitigation Act that set emissions standards for electric power generation.⁶⁸⁹ All electric utilities that commence operations after June 30, 2008, must meet a performance standard for emissions that is equal to the lesser of 1,100 pounds of GHGs per MW-hour of electricity generated or the average emissions of a new combined-cycle natural gas thermal electric generation turbine as determined by the Washington Department of Community, Trade, and Economic Development.⁶⁹⁰ Plants powered by renewable resources and existing cogeneration facilities powered by natural gas or waste fuel are considered in compliance with the emission standards.⁶⁹¹ Carbon that is captured and stored is also exempted from emissions calculations.

The following greenhouse gas emissions produced by baseload electric generation owned or contracted through a long-term financial commitment shall not be counted as emissions of the power plant in determining compliance with the greenhouse gas emissions performance standard:

- (a) Those emissions that are injected permanently in geological formations;
- (b) Those emissions that are permanently sequestered by other means approved by the department; and
- (c) Those emissions sequestered or mitigated as approved under subsection (16) of this section [outlining criteria for approval of a CCS plan].⁶⁹²

The legislation also requires that any long-term financial commitments to purchase energy by electric companies or consumer-owned utilities may only be entered into with facilities that meet the emissions limits.⁶⁹³

As required by the Climate Change Mitigation Act, the Department of Ecology adopted rules in 2008 that include criteria for evaluating the carbon sequestration plan for any CCS used to avoid emissions limits.⁶⁹⁴ The first rule includes a performance standard for sequestration, and another amends the state rules on underground injection to cover CO₂.⁶⁹⁵ Carbon sequestration requires a permit issued under Washington's Waste Discharge Permit Program.⁶⁹⁶ Washington State's underground injection rules for geologic sequestration of CO₂ are comprehensive and similar, but not identical, to the federal UIC rules. They aim to assure GHGs

⁶⁸⁸ WASH. REV. CODE ANN. § 70.235.020 (West 2010).

⁶⁸⁹ Washington ESSB 6001 (2007); codified at WASH. REV. CODE ANN. §§ 80.80.005 *et seq.* (West 2010).

⁶⁹⁰ WASH. REV. CODE ANN. §§ 80.80.40(1) & 80.80.50 (West 2010).

⁶⁹¹ WASH. REV. CODE ANN. §§ 80.80.40(4) & (5) (West 2010).

⁶⁹² WASH. REV. CODE ANN. § 80.80.40(10) (West 2010).

⁶⁹³ WASH. REV. CODE ANN. § 80.80.60 & 70 (West 2010).

⁶⁹⁴ See WASH. ADMIN. CODE §§ 173-218-010 through 173-218-130 (West 2010).

⁶⁹⁵ WASH. ADMIN. CODE §§ 173-218-115 & 173-407-110 (West 2010).

⁶⁹⁶ WASH. ADMIN. CODE § 173-218-115-2 (West 2010).

remain sequestered for at least one-thousand years.⁶⁹⁷ The rules place the responsibility for the sequestration site on the operator until the post-closure requirements are completed and the Department of Ecology confirms, in writing, that the requirements have been met.⁶⁹⁸ There also are air quality rules covering CO₂ emissions.⁶⁹⁹

On May 21, 2009, Governor Chris Gregoire issued Executive Order 09-05, which directs state agencies to continue work with the WCI, work with companies emitting more than 25,000 metric tons on emissions reduction strategies, work with industry to develop emissions benchmarks, work with the Centralia coal-fired generation plant to reduce emissions by half, and take other measures to combat climate change.⁷⁰⁰

§ 4(r). Wyoming's CCS Efforts

Wyoming has one underground and nineteen surface coal mines. Its 2009 production was 431,107 million tons. This is 73.70 percent of western U.S. production and 40.11 percent of the nation's production, which makes Wyoming the number one coal producing state in the nation.⁷⁰¹ Coal-fired power plants generate 95 percent of the electric power in the state.⁷⁰² There are twenty-three coal-fired power plants with a capacity of 6,168 MW in Wyoming; four of the plants are larger than 500 MW.⁷⁰³ On a per capita basis, Wyoming is in first place among states for CO₂ emissions.⁷⁰⁴

DOE awarded \$66.9 million to the Big Sky Regional Carbon Sequestration Partnership in November 2008 to demonstrate the suitability of the Nugget Sandstone formation in Wyoming for storage of over two million tons of CO₂. The CO₂ will come from Cimarex Energy's proposed helium and natural gas processing plant at Riley Ridge and be injected 11,000 feet below ground.⁷⁰⁵

Although Wyoming is only an observer in the WCI, and its congressional representatives have actively opposed federal cap-and-trade legislation,⁷⁰⁶ Wyoming has been very proactive in creating a legal framework for carbon

⁶⁹⁷ WASH. ADMIN. CODE § 173-407-110 (West 2010).

⁶⁹⁸ WASH. ADMIN. CODE § 173-218-115 (West 2010).

⁶⁹⁹ See WASH. REV. CODE ANN. § 70.94.151 (West 2010).

⁷⁰⁰ Wash. Exec. Order 09-05 (May 21, 2009).

⁷⁰¹ EIA Mine Type, *supra* note 375.

⁷⁰² Source Watch, *Wyoming and Coal*, http://www.sourcewatch.org/index.php?title=Wyoming_and_coal (last visited Dec. 10, 2010).

⁷⁰³ *Id.*

⁷⁰⁴ *Id.*

⁷⁰⁵ *Id.*

⁷⁰⁶ See Dustin Bleizeffer, *Senators Say They'll Fight Cap-and-Trade Legislation*, BILLINGS GAZETTE, Aug. 20, 2009, available at http://billingsgazette.com/news/state-and-regional/wyoming/article_6d5b0f10-8d3c-11de-9c38-001cc4c03286.html (last visited Dec. 10, 2010).

sequestration. Recently, Wyoming enacted several laws to regulate carbon sequestration. Some of the major legislation is detailed below.

§ 4(r)(1). House Bill 89: Pore Space Rights.

Effective July 1, 2008, Wyoming House Bill 89 establishes the ownership of pore spaces under the surface for means of carbon sequestration.⁷⁰⁷ Wyoming defines pore space as the “subsurface space which can be used as storage space for carbon dioxide or other substances.”⁷⁰⁸ Ownership of all pore spaces below the land and waters of Wyoming are to be vested in the owners of the surface rights above the pore space.⁷⁰⁹

When surface rights are conveyed pore space below the strata is also conveyed unless pore space has previously been severed or is explicitly excluded in the conveyance.⁷¹⁰ Ownership of pore space shall be conveyed under the law of conveyance regarding mineral interests, but no mineral or other sub-surface agreement shall automatically convey pore space unless agreements explicitly state so.⁷¹¹ “All instruments which transfer the rights to pore space under this section shall describe the scope of any right to use the surface estate. The owner of any pore space right shall have no right to use the surface estate beyond that set out in a properly recorded instrument.”⁷¹²

Transfers of pore space after July 1, 2008, may be deemed by the surface estate owner as null and void if the agreement does not include specific descriptions of the location of the pore space being transferred.⁷¹³ “The validity of pore space rights under this subsection shall not affect the respective liabilities of any party and such liabilities shall operate in the same manner as if the pore space transfer were valid”⁷¹⁴.

Notice laws regarding notice to surface and mineral owners shall not be construed to require sending notice to pore space owners unless law explicitly includes pore space owners.⁷¹⁵ Similarly, nothing in the bill is to change or alter the common law relating to rights or dominance of the mineral estate.⁷¹⁶ In determining priority of subsurface uses, mineral estates dominate regardless of “whether ownership of the pore space is vested in the several owners of the surface or is owned separately from the surface.”⁷¹⁷ The law

⁷⁰⁷ WYO. STAT. ANN. § 34-1-152 (2009).

⁷⁰⁸ WYO. STAT. ANN. § 34-1-152(d) (2009).

⁷⁰⁹ WYO. STAT. ANN. § 34-1-152(a) (2009).

⁷¹⁰ WYO. STAT. ANN. § 34-1-152(b) (2009).

⁷¹¹ *Id.*

⁷¹² WYO. STAT. ANN. § 34-1-152(f) (2009).

⁷¹³ WYO. STAT. ANN. § 34-1-152(g) (2009). The description may include but is not limited to a subsurface geologic or seismic survey or a metes and bounds description of the surface lying over the transferred pore space. *Id.* In the event a description of the surface is used, the transfer shall be deemed to include pore space at all depths underlying the described surface area unless specifically excluded. *Id.*

⁷¹⁴ *Id.*

⁷¹⁵ WYO. STAT. ANN. § 34-1-152(c) (2009).

⁷¹⁶ WYO. STAT. ANN. § 34-1-152(e) (2009).

⁷¹⁷ *Id.*

also does not “alter, amend, diminish or invalidate rights to the use of subsurface pore space that were acquired by contract or lease prior to July 1, 2008.”⁷¹⁸ The Act also provides that parties with geologic sequestration rights must be parties to a conservation easement that would deny them reasonable surface use.⁷¹⁹

§ 4(r)(2). House Bill 58: CO₂ Ownership and Liability.

Effective July 1, 2009, Wyoming House Bill 58, now codified as WYO. STAT. ANN. § 34-1-153 (2009), establishes ownership of material injected into geologic sequestration sites and liability related to sequestration sites. All CO₂ and incidental substances injected into a geologic sequestration site for the purpose of geologic sequestration are presumed to be owned by the injector of such material.⁷²⁰ Consequently, all rights, benefits, burdens and liabilities regarding the material shall also belong to the injector.⁷²¹ “This presumption may be rebutted by a person claiming contrary ownership by a preponderance of the evidence in an action to establish ownership.”⁷²²

Owners of pore space or other persons holding rights to control the pore space, surface, or other subsurface rights, shall not be liable for the effects of injecting CO₂ or incidental substances for the purpose of geologic sequestration solely because they consented to the injection.⁷²³

§ 4(r)(3). House Bill 90: Rules for Geologic Sequestration.

Effective July 1, 2008, House Bill 90, now codified as in Wyoming’s Statutes as sections 35-11-313 and 3-5-501 (2008), regulates the permitting of carbon sequestration within the state of Wyoming. Under Wyoming law, carbon sequestration⁷²⁴ is prohibited unless permitted by the Wyoming Department of Environmental Quality’s Division of Water Quality.⁷²⁵

For temporary permits or pilot programs, Wyoming law directs the Administrator of the Division of Water Quality to issue permits under current administrative rules.⁷²⁶ For requests for permanent sequestration, the Administrator shall recommend rules, regulations, and standards after receiving public comment on the issue and consulting with the Wyoming State Geologist, Wyoming Oil and Gas Conservation Commission, and the Carbon Sequestration Advisory Board (created by this act).⁷²⁷ These rules and

⁷¹⁸ WYO. STAT. ANN. § 34-1-152(h) (2009).

⁷¹⁹ WYO. STAT. ANN. § 34-1-202(e) (West 2010).

⁷²⁰ WYO. STAT. ANN. § 34-1-153(a) (2009).

⁷²¹ *Id.*

⁷²² *Id.*

⁷²³ WYO. STAT. ANN. § 34-1-153(b) (2009).

⁷²⁴ Using CO₂ for enhanced oil and gas recovery approved by the Wyoming Commission on Oil and Gas is not included under these carbon sequestration provisions unless the operator converts the injection site to a sequestration site at the end of operations. WYO. STAT ANN. § 35-11-313(b) and (c) (2008).

⁷²⁵ WYO. STAT. ANN. § 35-11-313(b) (2008).

⁷²⁶ WYO. STAT. ANN. § 35-11-313(d) (2008).

⁷²⁷ WYO. STAT. ANN. § 35-11-313(f) (2008).

regulations shall include the following required information. First, to regulate and permit carbon sequestration, the Administrator shall create a subclass of wells able to protect human health, safety, and environment within the EPA's Safe Drinking Water Act Underground Injection Control program.⁷²⁸ Second, the administrator must create a permit application⁷²⁹ for geologic sequestration. Applications for sequestration permits shall include the following:

- 1) relevant geologic description of injection site;
- 2) characterization of aquifers within injection zone that may be affected by injection and data describing projected effects;
- 3) identification of all other drill holes and operating wells that exist within and adjacent to the proposed sequestration site;
- 4) expected impact of injection on fluid resources, subsurface structures, and surface and necessary mitigation measures;
- 5) plans and procedures for environmental surveillance, detection, prevention, and control for CO₂ migrating at or beyond boundary of the site;
- 6) description of site and proposed sequestration facilities and documentation of all legal rights necessary to sequester CO₂ at the site.⁷³⁰
- 7) proof that the proposed injection wells are designed, at a minimum, to the construction standards set forth by the Department of Environmental Quality and the Wyoming Oil and Gas Conservation Commission;
- 8) a plan for periodic mechanical integrity testing of all wells;
- 9) a monitoring plan to assess the migration of the injected CO₂ and to insure the retention of the CO₂ in the geologic sequestration site;
- 10) proof of bonding or financial assures to ensure sequestration sites and facilities will be lawfully constructed, operated and closed;
- 11) a detailed plan for post-closure monitoring, verification, maintenance and mitigation;
- 12) proof of notice, including at a minimum publishing notice in a newspaper of general circulation in each county of proposed operation for four consecutive weeks and sending a copy of that notice to each surface owner, mineral claimant, mineral owner, lessee and any other owners of record of subsurface interests within one mile of the proposed boundary of the sequestration site.⁷³¹

⁷²⁸ WYO. STAT. ANN. § 35-11-313(f)(i) (2008).

⁷²⁹ At the time a permit application is filed, an applicant shall pay a fee to be determined by the director based upon the estimated costs of reviewing, evaluating, processing, serving notice of an application and holding any hearings. The fee shall be credited to a separate account and shall be used by the division as required to complete the tasks necessary to process, publish and reach a decision on the permit application. Unused fees shall be returned to the applicant. WYO. STAT. ANN. § 35-11-313(h) (2008).

⁷³⁰ The department may issue a draft permit contingent on obtaining a unitization order pursuant to WYO. STAT. ANN. §§ 35-11-314 through 35-11-317 (enacted through Wyo. H.B. 80 in 2009).

⁷³¹ WYO. STAT. ANN. § 35-11-313(f)(ii)(A) - (N) (2008).

Third, in addition to these application requirements, the Administrator of the Division of Water Quality must require operators of sequestration sites to provide immediate verbal notification to the Department of Environmental Quality if any migrating CO₂ is discovered. The operator must then provide, within 30 days of detection, written notice to all surface owners, mineral claimants, mineral owners, lessees and other owners of record of subsurface interests of the discovery.⁷³²

Fourth, the Administrator must promulgate “procedures for the termination or modification of any applicable UIC permit issued under Part C of the SDWA if an excursion cannot be controlled or mitigated.”⁷³³ The Administrator may also set other needed conditions and requirements to manage CCS.⁷³⁴

House Bill 90 directs the State Oil and Gas Supervisor, the Director of the Department of Environmental Quality, and the State Geologist to convene a working group for the “purpose of developing an appropriate bonding procedure and other financial assurance methods to assure that adequate financial resources are provided to pay for any mitigation or reclamation costs.”⁷³⁵ At minimum this bond or other financial assurance “shall provide assurance for closure and reclamation costs, post-closure inspection and maintenance costs and environmental monitoring, verification and control costs.” As required by the law, the group reported the findings and recommendations to the joint Minerals, Business and Economic Development and joint Judiciary Interim committees in September, 2009.⁷³⁶

House Bill 90 also provides that the Director of the Department of Environmental Quality “shall recommend to the [Environmental Quality] Council any changes that may be required to provide consistency and equivalency between the rules or regulations promulgated under this section and any promulgated for the regulation of [CO₂] sequestration by the United States Environmental Protection Agency.”⁷³⁷ In addition, “the Wyoming [Oil and Gas] Conservation [Commission] shall have jurisdiction over any subsequent extraction of sequestered carbon dioxide that is intended for commercial or industrial purposes.”⁷³⁸

§ 4(r)(4). House Bill 17: Financial Assurance and Long-term Stewardship.

In 2010, the Wyoming legislature passed laws establishing a Geologic Sequestration Special Revenue Account and requiring certain financial assurances from CCS operators, including insurance. The Special Revenue Account is made up

⁷³² WYO. STAT. ANN. § 35 -11-313(f)(iii) (2008).

⁷³³ WYO. STAT. ANN. § 35 -11-313(f)(iv) (2008).

⁷³⁴ WYO. STAT. ANN. § 35 -11-313(f)(v) (2008).

⁷³⁵ WYO. STAT. ANN. § 35 -11-313(g) (2008).

⁷³⁶ *Id.* See also Wyoming Department of Environmental Quality, Carbon Sequestration Working Group, <http://deq.state.wy.us/carbonsequestration.htm> (last visited Dec. 13, 2010) for additional information on the working group and their publications.

⁷³⁷ WYO. STAT. ANN. § 35 -11-313(j) (2008).

⁷³⁸ WYO. STAT. ANN. § 35 -11-313(k) (2008).

fees collected by the Department of Environmental Quality to cover the costs of measuring, monitoring, and verifying a sequestration site after it receives a closure certificate.⁷³⁹ It does not appear that Wyoming will assume liability for the site or the injected CO₂, even after issuing a closure certificate:

The existence, management and expenditure of funds from this account shall not constitute a waiver by the state of Wyoming of its immunity from suit, nor does it constitute an assumption of any liability by the state for geologic sequestration sites or the carbon dioxide and associated constituents injected into those sites.⁷⁴⁰

The Act also adds financial assurance requirements to obtain a permit for CO₂ sequestration. The Administrator of the Water Quality Division must recommend further rules for CCS regulation. A CCS operator must now provide proof of a public liability insurance policy,⁷⁴¹ bonding and financial assurance, periodic reports substantiating the adequacy of financial assurances, and proof of compliance with financial requirements. The Administrator is also required to establish procedures for replacement of required financial instruments, procedures for terminating bonds and financial assurances no sooner than 10 years after completion of operations, recording requirements so that permitted CCS sites can be located during a title search, and the fees that will be required to fund the Special Revenue Account, which may include a per-ton fee on injections or a closure fee.⁷⁴² The Department of Environmental Quality is also authorized to hire a full-time accountant to manage the financial assurances required by this act.⁷⁴³

§ 4(r)(5). Other Wyoming Legislation: HB 57 and SB 1.

H.B. 57 of 2009 affirms that the mineral estate remains the dominant estate and has priority over pore space ownership.⁷⁴⁴ S.B. 1 of 2008 provides funding for CCS technologies and activities. \$1,223,866 is made available for the evaluation of potential CO₂ sequestration sites and activities related to the advancement of clean coal and carbon management activities.⁷⁴⁵ The spending bill also provides \$1,822,481 for Clean Coal technology, directed at specified projects, including capture from coal combustion flue gas.⁷⁴⁶

⁷³⁹ WYO. STAT. ANN. § 35-11-318(b) (2010).

⁷⁴⁰ WYO. STAT. ANN. § 35-11-318(d) (2010).

⁷⁴¹ WYO. STAT. ANN. § 35-11-313(f)(ii)(O) (2010).

⁷⁴² WYO. STAT. ANN. § 35-11-318(f)(iv) (2010).

⁷⁴³ Wyo. H.B. 17, § 4(a)(ii) (2010).

⁷⁴⁴ WYO. STAT. ANN. § 34-1-152 (2009).

⁷⁴⁵ Wyo. S.B. 1, § 320(iii) (2008).

⁷⁴⁶ Wyo. S.B. 1, § 325(a) (2008).

§ 5. Conclusion

With the federal government's failure to enact legislation regulating CO₂ or establishing a national cap-and-trade program, regional and state actions are becoming increasingly important.⁷⁴⁷ While the fate of national and global actions to combat climate change are uncertain, much time, money, and planning has been invested by state and regional bodies to define, regulate, and promote CCS. The review of western states' initiatives shows that even states with such different stances on climate change and government regulation as California and Texas have indicated governmental support for CCS and enacted extensive and often similar legislation to regulate it. Funding for CCS has increased dramatically over the past decade, and although it still faces substantial technological and financial hurdles, some of the political and legal hurdles are being addressed in several states.

The adoption of a cap-and-trade program for GHGs will give states such as California and New Mexico at least one advantage in implementing CCS and clean coal technologies. By making carbon emissions a major cost item for electricity generators, cap-and-trade will make CCS more attractive and economically practical. If the choice is between investing in yearly allowances to continue the status quo or investing in new technology, large coal-fired plants may finally have the needed incentives and cost analyses to upgrade. However, such analyses will also likely take into account the regulatory burdens and the uncertainty generated by the social/political atmosphere surrounding the continued use of coal and hydrocarbons.

Coal is still a major energy source for many states and regions that cannot easily or immediately be replaced. Increasing global demand may also counter several states' efforts to eliminate coal from their energy portfolios. One commentator's conclusion may be unavoidable: "For now, the only way to meet the world's energy needs, and to arrest climate change before it produces irreversible cataclysm, is to use coal—dirty, sooty, toxic coal—in more-sustainable ways."⁷⁴⁸ Whether California and New Mexico's self-imposed cap-and-trade program or Texas and Wyoming's industry-friendly regulations will be more conducive to advancing CCS remains to be seen.

⁷⁴⁷ See, e.g., *Plan B - Going It Alone: Regional Programs in North America*, POINT CARBON (Feb. 25, 2010), available at <http://www.pointcarbon.com/research/cmana/1.1416963> (last visited Dec. 30, 2010); Sean Pool. *The Proof Is in the Pudding: Regional Greenhouse Gas Initiative Shows Pollution Pricing Works*. CENTER FOR AMERICAN PROGRESS (March 22, 2010), available at http://www.americanprogress.org/issues/2010/03/rggi_roadmap.html (last visited Dec. 30, 2010); Bruce Usher, *On Global Warming, Start Small*, NEW YORK TIMES, (Nov. 27, 2010).

⁷⁴⁸ James Fallows, *Dirty Coal, Clean Future*, THE ATLANTIC (Dec. 2010), available at <http://www.theatlantic.com/magazine/archive/2010/12/dirty-coal-clean-future/8307/> (last visited Dec. 13, 2010).